THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this Document or the action you should take, you are recommended to seek your own financial advice immediately from an appropriately authorised stockbroker, bank manager, solicitor, accountant or other independent financial adviser who, if you are taking advice in the United Kingdom, is duly authorised under the Financial Services and Markets Act 2000 ("FSMA").

This Document comprises a prospectus relating to Predator Oil & Gas Holdings Plc (the "**Company**") prepared in accordance with the prospectus regulation rules of the United Kingdom Financial Conduct Authority (the "**FCA**") made under section 73A of FSMA (the "**Prospectus Regulation Rules**") and approved by the FCA as competent authority under Regulation (EU) 2017/1129 (the "**Prospectus Regulation**") under section 87A of FSMA. This Document has been filed with the FCA and made available to the public in accordance with Rule 3.2 of the Prospectus Regulation Rules. The FCA only approves this Document as meeting the standards of completeness, comprehensibility and consistency imposed by the Prospectus Regulation. Such approval should not be considered as an endorsement of the Company that is, or the securities that are, the subject of this Document. Investors should make their own assessment as to the suitability of investing in the Ordinary Shares of Predator Oil & Gas Holdings Plc.

Application(s) will be made to the FCA for the New Ordinary Shares to be admitted to the Official List of the FCA (the "**Official List**") (by way of a standard listing under Chapter 14 of the listing rules published by the FCA under section 73A of FSMA as amended from time to time (the "**Listing Rules**")) and to London Stock Exchange plc (the "**London Stock Exchange**") for such New Ordinary Shares to be admitted to trading on the London Stock Exchange's main market for listed securities (together, "**Admission**"). It is expected that Admission will become effective, and that unconditional dealings in the New Ordinary Shares will commence, at 8.00 a.m. on 28 February 2020.

THE WHOLE OF THE TEXT OF THIS DOCUMENT SHOULD BE READ BY PROSPECTIVE INVESTORS. YOUR ATTENTION IS SPECIFICALLY DRAWN TO THE DISCUSSION OF CERTAIN RISKS AND OTHER FACTORS THAT SHOULD BE CONSIDERED IN CONNECTION WITH AN INVESTMENT IN THE ORDINARY SHARES, AS SET OUT IN THE SECTION ENTITLED "RISK FACTORS" BEGINNING ON PAGE 13 OF THIS DOCUMENT.

The Directors, whose names appear on page 6, and the Company accept responsibility for the information contained in this Document. To the best of the knowledge of the Directors and the Company, the information contained in this Document is in accordance with the facts and this Document contains no omission likely to affect its import.

PREDATOR OIL & GAS HOLDINGS PLC

(incorporated and registered in Jersey under the Companies (Jersey) Law 1991 (as amended) with registered number 125419)

Placing of 89,000,000 New Ordinary Shares at 4 pence per New Ordinary Share

Joint Brokers and Placing Agents

OPTIVA SECURITIES LIMITED

and

NOVUM SECURITIES LIMITED

The Placing comprises an offer by the Company of 89,000,000 New Ordinary Shares. This Document does not constitute an offer to sell or an invitation to subscribe for, or the solicitation of an offer or invitation to buy or subscribe for, Ordinary Shares in any jurisdiction where such an offer or solicitation is unlawful or would impose any unfulfilled registration, publication or approval requirements on the Company.

The New Ordinary Shares have not been and will not be registered under the US Securities Act of 1933, as amended (the "**Securities Act**"), or the securities laws of any state or other jurisdiction of the United States or under applicable securities laws of Australia, Canada, Japan or the Republic of South Africa. Subject to certain exceptions, the New Ordinary Shares may not be, offered, sold, resold, transferred or distributed, directly or indirectly, within, into or in the United States or to or for the account or benefit of persons in the United States, Australia, Canada, Japan, the Republic of South Africa or any other jurisdiction where such offer or sale would violate the relevant securities laws of such jurisdiction.

The distribution of this Document in or into jurisdictions other than the United Kingdom may be restricted by law and therefore persons into whose possession this Document comes should inform themselves about and observe any such restrictions. Any failure to comply with these **restrictions** may constitute a violation of the securities laws of any such jurisdiction.

The New Ordinary Shares have not been approved or disapproved by the US Securities Exchange Commission, any State securities commission in the United States or any other US regulatory authority, nor have any of the foregoing authorities passed comment upon or endorsed the merits of the Placing or adequacy of this Document. Any representation to the contrary is a criminal offence in the United States.

Application will be made for the New Ordinary Shares to be admitted to a Standard Listing on the Official List. A Standard Listing will afford investors in the Company a lower level of regulatory protection than that afforded to investors in companies with Premium Listings on the Official List, which are subject to additional obligations under the Listing Rules. It should be noted that the FCA will not have the authority to (and will not) monitor the Company's compliance with any of the Listing Rules, nor to impose sanctions in respect of any failure by the Company to so comply.

A copy of this Document has been delivered to the registrar of companies in Jersey in accordance with Article 5 of the Companies (General Provisions) (Jersey) Order 2002, and he has given, and has not withdrawn, his consent to its circulation.

The Jersey Financial Services Commission has given, and has not withdrawn, its consent under Article 2 of the Control of Borrowing (Jersey) Order 1958 to the issue of securities in the Company.

It must be distinctly understood that, in giving these consents, neither the registrar of companies in Jersey nor the Jersey Financial Services Commission takes any responsibility for the financial soundness of the Company or for the correctness of any statements made, or opinions expressed, with regard to it.

If you are in any doubt about the contents of this Document you should consult your stockbroker, bank manager, solicitor, accountant or other financial adviser. It should be remembered that the price of securities and the income from them can go down as well as up.

The Directors have taken all reasonable care to ensure that the facts stated in this Document are true and accurate in all material respects, and that there are no other facts the omission of which would make misleading any statement in the document, whether of fact or of opinion. All the Directors accept responsibility accordingly.

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PART I
SUMMARY

INTRODUCTION

This summary is made up of four sections and contains all the sections required to be included in a summary for this type of securities and issuer. Even though a sub-section may be required to be inserted in the summary because of the type of securities and issuer, it is possible that no relevant information can be given regarding the subsection. In this case, a short description of the sub-section is included in the summary with the mention of ‘‘not applicable”.

INTRODUCTIONS AND WARNINGS		
	Name and ISIN of the securities	The securities subject to admission are Ordinary Shares of no par value which will be registered with ISIN JE00BFZ1D698 and SEDOL number BFZ1D69.
	Identity and contact details of the issuer	The issuer is Predator Oil & Gas Holdings Plc, and its registered address is 3rd Floor, Standard Bank House, 47 – 49 La Motte Street, Jersey JE2 4SZ and its telephone number is +44 (0) 1534 834 600. The Company’s LEI is 213800L7QXFURBFLDS54.
	Identity and contact details of the competent authority approving the prospectus	The competent authority approving the prospectus is the FCA. The FCA’s registered address is at 12 Endeavour Square, London E20 1JN, United Kingdom and telephone number is +44 (0)20 7066 1000.
	Date of approval of the prospectus	The prospectus was approved on 19 February 2020.
	Warnings	This summary should be read as an introduction to this Document. Any decision to invest in the New Ordinary Shares should be based on consideration of this Document as a whole by the Investor. An Investor could lose all or part of any invested capital in Predator Oil & Gas Holdings Plc. Where a claim relating to the information contained in this Document is brought before a court the plaintiff Investor might, under the national law, have to bear the costs of translating this Document before legal proceedings are initiated. Civil liability attaches only to those persons who have tabled this summary including any translation thereof but only where this summary is misleading, inaccurate or inconsistent when read together with the other parts of this Document or it does not provide, when read together with the other parts of this Document, key information in order to aid investors when considering whether to invest in such securities.

<table>
<tr><th colspan="3">KEY INFORMATION ON THE ISSUER</th></tr>
<tr><td colspan="3">Who is the issuer of the securities?</td></tr>
<tr><td>6(A) i-v</td><td>Domicile and legal form</td><td>The Company is a public company incorporated in Jersey on 19 December 2017 and listed on the London Stock Exchange (Standard List) on 24 May 2018. The Company operates in accordance with the Companies (Jersey) Law 1991. Predator's LEI is 213800L7QXFURBFLDS54.</td></tr>
<tr><td></td><td>Principal activities</td><td>The Company is involved in the exploration, appraisal and further development of oil and gas assets.

The Company operates in Morocco and Ireland. The Company is a non-operator in the Republic of Trinidad and Tobago.

The principal near-term activities of the Company are exploration drilling for gas onshore Morocco and injecting carbon dioxide into existing wells in Trinidad for enhanced oil recovery and carbon dioxide sequestration.</td></tr>
<tr><td></td><td>Group strategy</td><td>The Group's strategy is to adopt an ethical and proactive response to the issue of climate change and its implications for the oil and gas sector.

The Group is focussed on developing a more environment-friendly fossil fuel business, where its business approach can be demonstrated as contributing to a potential reduction in CO2 emissions.

To achieve this the Group is concentrating on gas, a cleaner fuel compared to oil, and injecting CO2, that is currently vented to the atmosphere, into oil reservoirs.

The Group only has activities in countries where there is a commitment to reducing CO2 emissions by replacing coal- and oil-fired power stations with gas as the energy source, and where CO2 emissions from ammonia plants can be utilised for subsurface sequestration in producing oil fields.

The Group's gas assets are close to infrastructure with under-utilised capacity. This strategy can reduce the lead time to development and production to bring forward potential monetisation, whilst facilitating an earlier impact on reducing CO2 emissions.

Early monetisation of its assets for the benefit of its shareholders is a key objective of the Company. This is potentially achievable through establishing and enhancing production in Trinidad and through the partial or complete sale of its gas assets at a stage where the development potential has been de-risked and where environmental regulatory compliance has been demonstrated and the CO2 emissions strategy clearly defined.</td></tr>
<tr><td></td><td>Major shareholders</td><td>The Company's major shareholders as at the date of this Document are:
<table>
<tr><th>Shareholder</th><th>No. of Ordinary Shares</th><th>Percentage of issued ordinary share capital</th></tr>
<tr><td>Paul Griffiths</td><td>44,773,294</td><td>41.39%</td></tr>
<tr><td>Ronald Pilbeam</td><td>7,273,294</td><td>6.72%</td></tr>
<tr><td>The Bank Of New York (Nominees) Limited</td><td>5,587,400</td><td>5.17%</td></tr>
</table>
</td></tr>
</table>

		Pershing Nominees Limited (a/c BICLT)	5,349,415	4.95%
		Hargreaves Lansdown (Nominees) Limited (a/c 15942)	5,077,438	4.69%
		Hargreaves Lansdown (Nominees) Limited (a/c VRA)	4,864,252	4.50%
		Interactive Investor Services Nominees Limited (a/c SMKTNOMS)	3,663,537	3.39%
		Wealth Nominees Limited	3,291,996	3.04%
		Hargreaves Lansdown (Nominees) Limited (a/c HLNOM)	3,229,822	2.99%

	Directors	The Company's board of directors as at the date of the Document are Carl Kindinger, Paul Stanard Griffiths, Ronald Pilbeam and Dr Stephen Staley.
	Statutory auditors	The Company's statutory auditors are PKF Littlejohn LLP.

What is the key financial information regarding the issuer?

	Selection of historical key financial information	The Company was incorporated on 19 December 2017 and the following tables set out the summary unaudited historical financial information of the Company as derived from the financial information of the Company which was drawn up as at 30 June 2019 and is not extracted from any statutory financial statements. Any figures quoted in relation to the years to 31 December 2017 and to 31 December 2018 are taken from the audited financial statements of the Company.
	Pro-forma financial information	***Table 1: income statement for non-financial entities (equity securities)***

	Year to 31 December 2018	Year to 31 December 2017	Six month period to 30 June 2019	Six month period to 30 June 2018
Operating loss	(793,473)	(448,646)	(472,273)	(305,865)
Net profit or loss	(792,461)	(448,646)	(512,263)	(305,865)
Earnings per share	(1.0)	-	(0.5)	(0.8)

Table 2: Balance sheet for non-financial entities (equity securities)

	Year to 31 December 2018	Year to 31 December 2017	Six month period to 30 June 2019
Total assets	989,472	589,743	1,926,513

		Total equity	919,202	582,384	838,323	
		Net financial debt (long-term debt plus short term debt minus cash)	-	-	627,162	

Table 3: Cash flow statement for non-financial entities (equity securities)

	Year to 31 December 2018	Year to 31 December 2017	Six month period to 30 June 2019	Six month period to 30 June 2018
Relevant net cash flows from operating activities	(619,097)	(147,425)	(1,650,260)	(267,526)

6(B)	**Brief description of any qualification in the audit report**	A clean audit opinion was given over the summary financial information presented within this section.

What are the key risks that are specific to the issuer?

6(C)	**Brief description of the most material risk factors specific to the issuer contained in the prospectus**	The Directors believe that the 15 most material risk factors are as follows: If the exploration well in Guercif Morocco is unsuccessful it may have an immediate impact on share performance. The ability to drill Guercif depends on: (a) securing a rig for drilling on acceptable commercial terms, (b) the approval of an Environmental Impact Assessment and (c) receiving regulatory and partner consents to drill. The extension of the term of the IPSC until 31 December 2021 is dependent upon CO2 injection commencing on or before 28 January 2020. Under the WPA terms, the Company has, from injection of CO2, until 30 September 2020 an exclusive right to acquire FRAM for an agreed cash consideration. There is a risk that the Company fails to proceed to acquire FRAM due to technical reasons, if the CO2 EOR Pilot Project fails to deliver enhanced oil production, lack of access to financial resources to complete an acquisition, and/or failure to receive MEEI regulatory approvals and consents. The profitability of the CO2 EOR Project is substantially dependent upon negotiating favourable commercial terms with Massy Gas Products Trinidad Ltd ("Massy") for the initial volumes of carbon dioxide required to enhance existing oil production. The ability to further develop the Guercif drilling opportunity in Morocco will depend upon the Company securing additional funding for drilling within the initial exploration period of the Licence which commenced on 19th March 2019. Failure to drill the commitment well within the Guercif Licence within the initial exploration period will result in the loss of the Company's bank guarantee in favour of ONHYM. Failure to find a drilling rig for Guercif on acceptable commercial terms, particularly if one has to be mobilised to Morocco, may impact the Company's ability to drill its gas prospect.

			Further development of the Licensing Options offshore Ireland is dependent upon the Company obtaining successor authorisations, which were applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018, the grant of which are conditional on the Company demonstrating, either by itself or with the addition of potential farm-in partners, a financial and technical operating capability to perform its exploration work obligations to be negotiated under the terms of any successor authorisations. No work programme has been committed to for the next 12 months and therefore the award of any successor authorisations will be dependent on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations. In Ireland the Group is particularly exposed to the issue of CO2 emissions in the context of the fossil fuel industry. The Climate Emergency Measures Bill (the "Bill") was proposed to limit the scope of the Petroleum and Other Minerals Development Act in respect of the issue of new licences for exploration and extraction of fossil fuels in Ireland. The precise details of the changing government policy with respect to fossil fuel exploration remain to be announced. As a consequence the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and the finance necessary to commit to a work programme for any successor authorisation. Under these circumstances, Ireland would not be progressed by the Company. However, the aforesaid opinion is predicated on the key forward looking assumptions inherent in this Prospectus. Nevertheless, the Directors believe the working capital forecast reflects a worst case scenario of possible outcomes. For the avoidance of doubt, the Company is of the opinion that the working capital available to the Group, taking into account the Net Placing Proceeds, is sufficient for the present requirements of the Group, that is, at least the 12 months from the date of this Document. The Directors believe the working capital forecast reflects a worst case scenario of possible outcomes and will ensure the availability of adequate financial resources over a 12 month period, but it is difficult to forecast the amount of additional capital required from time to time. The Company has a CLN with Arato Global Opportunities (the "Lender") for which the outstanding balance is £1.015 million. The CLN, if not converted, is repayable in cash after 24 months to an amount of 105% of the amount outstanding plus a fee of 10% of the principal amount being repaid. There is no impact to the Company in the 12-month working capital forecast period. Under the terms of the CLN the Lender is entitled to 25% of any Placing funds to be made available for a cash repayment of the outstanding balance of the loan. The Company has agreed to issue to the Lender 2,500,000 Ordinary Shares at the Placing Price in consideration for the Lender waiving the requirement pursuant to the CLN that the Company pay to the Lender up to 25 per cent. of the Placing funds in cash. These Ordinary Shares will be issued following Admission, conditional on the Company

		obtaining new Shareholder approval for such issue, and do not form part of the New Ordinary Shares.
KEY INFORMATION ON THE SECURITIES		
	Type, class and ISIN	The securities being admitted to trading on the Main Market of the London Stock Exchange with a Standard Listing are New Ordinary Shares of no par value each. The Ordinary Shares will be registered with ISIN JE00BFZ1D698 and SEDOL number BFZ1D69.
	Currency, denomination, par value, number of securities issued and the term of the securities	The Ordinary Shares are denominated in UK Sterling ("**GBP**") and the subscription price will be paid in GBP. The issued share capital of the Company on Admission will consist of 197,172,169 Ordinary Shares (comprising the Existing Ordinary Shares and New Ordinary Shares).
7(A)	**Rights attached to the securities**	The New Ordinary Shares rank equally with the Existing Ordinary Shares for voting purposes. On a show of hands, each Shareholder has one vote and on a poll each Shareholder has one vote per Ordinary Share held. The Ordinary Shares rank equally for dividends declared and for any distributions on a winding-up. The Ordinary Shares rank equally in the right to receive a relative proportion of shares in the case of a capitalisation of reserves. There are no other securities issued by the Company and so no class of securities ranks ahead of, or alongside, the Ordinary Shares in the event of an insolvency.
	Relative seniority of the securities in the issuer's capital structure in the event of insolvency	Not applicable. The Company does not have any other securities in issue or liens over its assets and so the Ordinary Shares are not subordinated in the Company's capital structure as at the date of this Prospectus, and will not be immediately following Admission.
	Restrictions on the free transferability of the securities	The Ordinary Shares are freely transferable save as specified in the Articles or as provided by the Companies (Jersey) Law 1991 (as amended).
	Dividend or pay-out policy	The Company's current intention is to distribute free cash from its operational activities in Trinidad to Shareholders subject to the ongoing capex and working capital constraints necessary in relation to prudent financial management of its business operations and business development. The Company will only pay dividends to the extent that to do so is in accordance with the Jersey Companies Law and all other applicable laws. The Directors do not anticipate declaring any dividends in the short to medium term.
Where will the securities be traded?		
7(B)	**Application for admission to trading**	Application will be made for the New Ordinary Shares to be listed on the Official List and to be traded on the Main Market of the London Stock Exchange with a Standard Listing. It is expected that Admission will become effective and that unconditional dealings will commence at 8.00 a.m. on 28 February 2020.

	Identity of other markets where the securities are or are to be traded	Not applicable. There is currently no other market for the Ordinary Shares and the Company does not intend to seek admission to trading of the Ordinary Shares on any market other than the Main Market.
What are the key risks that are specific to the securities?		
7(D)	**Brief description of the most material risk factors specific to the securities contained in the prospectus**	• A Standard Listing affords Shareholders less regulatory protection than a Premium Listing, which may have an adverse effect on the valuation of the Ordinary Shares. • If the warrants in issue on Admission are exercised, Shareholders may be diluted. Assuming no change to the Enlarged Share Capital, the maximum total dilution which would result from the exercised Warrants is 2.26 per cent. • The Company's share price will fluctuate and may decline as a result of a number of factors, some of which are outside of the Company's control.
KEY INFORMATION ON THE ADMISSION TO TRADING ON A REGULATED MARKET		
Under which conditions and timetable can I invest in this security?		
8(a)	**General terms and conditions**	The Placing is conditional, inter alia, on Admission having become effective at or before 8.00 a.m. on 28 February 2020 (or such later time and date as the Company may decide, being not later than 8.00 a.m. on 31 March 2020). The estimated Net Placing Proceeds are approximately £3,305,000. The total expenses incurred by the Company in connection with Admission and Placing are approximately £255,000 in cash and a further £95,000 to be satisfied by the issue of 2,375,000 Ordinary Shares at the Placing Price to be issued conditional on Shareholder approval. These Ordinary Shares will be issued following Admission and do not form part of the New Ordinary Shares.
	Expected timetable of the offer	Publication of this Document: 19 February 2020 Admission and commencement of unconditional dealings in the New Ordinary Shares: 8:00 a.m. on 28 February 2020 (and not later than 8:00 a.m. on 31 March 2020) CREST members' accounts credited in respect of New Ordinary Shares: 28 February 2020. All of the New Ordinary Shares are to be issued in uncertificated form.
	Details of admission to trading on a regulated market	Application will be made for the New Ordinary Shares to be admitted to a Standard Listing on the Official List and to trading on the Main Market of the London Stock Exchange. It is expected that Admission will become effective and that dealings in the New Ordinary Shares will commence at 8:00 a.m. on 28 February 2020.
	Plan for distribution	The New Ordinary Shares which are the subject of this Document will be offered by Optiva and Novum.

	Amount and percentage of immediate dilution resulting from the offer	The issue of New Ordinary Shares in the Placing will result in existing Shareholders being diluted (to the extent they do not participate in the Placing) by 82.28 per cent.
	Estimate of total expenses of the issue and/or offer	The transaction costs will be borne by the Company in full and no expenses will be charged to the Investors. Conditional only on the Placing, the Company has raised gross proceeds of £3,560,000 through the Placing, and Net Placing Proceeds of approximately £3,305,000. The total expenses incurred (or to be incurred) by the Company in connection with the Placing are approximately £255,000 in cash and a further £95,000 to be satisfied by the issue of 2,375,000 Ordinary Shares at the Placing Price to be issued conditional on Shareholder approval. These Ordinary Shares will be issued following Admission and do not form part of the New Ordinary Shares.
	Why is this prospectus being produced?	
8(C)	**Reasons for the offer or for the admission to trading on a regulated market**	This Document, which constitutes a prospectus pursuant to the Prospectus Regulation Rules, is being produced in connection with the application to be made by the Company for the New Ordinary Shares to be admitted to trading on the Main Market of the London Stock Exchange with a standard listing. The Placing is not being underwritten and there are no material conflicts of interest relating to the proposed admission to trading.
	Use and estimated net amount	The estimated Net Placing Proceeds are approximately £3,305,000, which the Company intends to apply in the following order of priority:

Morocco – Guercif	**£**
Well planning, design and environmental	121,465
Drill site civil works	38,750
Rig mobilisation/demobilisation	116,248
Drilling well to 2,000 meters inclusive casing, mud, wireline logging, MDT tool, directional survey, camp and well clean-up (20 day well)	1,550,338
Well supervision	52,500
Incorporating and running Moroccan branch company with in-country manager	46,510
Trinidad – CO2 EOR Inniss-Trinity (Company receives only a share of profits from production)	
FRAM HSE, well operations and management of downhole completions	21,648

		Civil works and road maintenance for CO2 truck deliveries	51,801
		New well heads and additional downhole equipment	64,448
		Additional well workovers	31,679
		Generator and installation	12,654
		Expansion of CO2 injection to include up to 3 additional reservoirs and up to 3 additional wells; new well workovers and completions for CO2 EOR for new wells and reservoirs in AT-4 Block; additional CO2 delivery system and increased CO2 supply requirement for CO2 EOR expansion	339,711
		CO2 injection Massy operator costs, security and standby C02 supply	77,052
		Telecommunications	9,302
		Real-time reservoir engineering and HSE monitoring	11,628
		Safety Equipment	13,976
		Well insurance	9,302
		Corporate running costs 12 months	413,772
		FCA prospectus costs	17,000
		Costs of professional advice in relation to prospectus	146,983
		Sub-Total	**3,146,767**
		Contingency 5%	158,233
		NET PROCEEDS TOTAL	**3,305,000**
	Indication of whether the offer is subject to an underwriting agreement	The Placing is not being underwritten. Optiva and Novum, as the Company's agents, have procured irrevocable commitments to subscribe for the full amount of the New Ordinary Shares from subscribers in the Placing, and there are no conditions attached to such irrevocable commitments other than Admission.	
	Indication of the most material conflicts of interests relating to the offer or admission to trading	Not applicable.	

PART II
RISK FACTORS

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.

Prospective Investors should note that the risks relating to the Company, its industry and the Ordinary Shares summarised in the section of this Document headed "Summary" are the risks that the Directors believe to be the most essential to an assessment by a prospective Investor of whether to consider an investment in the Shares. However, as the risks which the Company faces relate to events and depend on circumstances that may or may not occur in the future, prospective Investors should consider not only the information on the key risks summarised in the section of this Document headed "Summary" but also, among other things, the risks and uncertainties described below.

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.

The risks are set out below in separate categories. Each risk factor has been set out only once and although some risk factors may cross over multiple categories, they have only been presented once in what the Company considers to be the most appropriate category. Within each category, the most material risk factors have been presented first.

These are risks specific to the Company that are attributable to the Company's business development strategy, subsurface objectives, commercial models and regulatory and environmental matters applicable to the licence interests within the different jurisdictions within which the Company operates.

RISKS RELATED TO THE ISSUER'S BUSINESS DEVELOPMENT STRATEGY

Financial risks

1) Arato Global Opportunities Convertible Loan Note ("**CLN**")

The Company has a CLN with Arato Global Opportunities (the "**Lender**") for which the outstanding balance is £1.015 million. The CLN, if not converted, is repayable in cash after 24 months to an amount of 105% of the amount outstanding plus a fee of 10% of the principal amount being repaid.

The CLN is convertible at the election of the Lender at 105% of the principal amount being converted at a conversion price calculated at 90% of the volume-weighted average share price of an Ordinary Share as shown on the London Stock Exchange for the two trading days immediately preceding the notice of conversion from the Lender.

In the event that the CLN does not convert into shares before the 24-month loan repayment date expires, the Company does not anticipate any difficulties making the outstanding cash repayment to the Lender.

The risk for the Company attached to the CLN is the lack of sufficient existing headroom shares for conversion should the volume-weighted average share price of an Ordinary Share as shown on the London Stock Exchange for the two trading days immediately preceding the notice of conversion

from the Lender be low. This in turn creates a market-perceived share overhang which may materially impact the ability of the Company to raise additional equity funds to develop its business development growth strategy.

There is no impact to the Company in the 12-month working capital forecast period but the longer-term impact could be material if the risk identified above materialised.

In the event the Company undertakes a placing, then the Lender is entitled to a CLN repayment of 25% of the placing proceeds in cash which may reduce the amount of working capital available to the Company for its current and future work programmes.

The Lender will waive this requirement in the case of the Placing to ensure that the Net Placing Proceeds satisfy the Company's intended current work programme and working capital forecast. In consideration for the Lender waiving this requirement, the Company has agreed to issue to the Lender 2,500,000 Ordinary Shares at the Placing Price. These Ordinary Shares will be issued following Admission, conditional on the Company obtaining new Shareholder approval for such issue, and do not form part of the New Ordinary Shares.

Commercial risks

Morocco

1) The ability to develop the gas potential of the area covered by the Guercif Petroleum Agreement depends on: (a) securing a rig for drilling on acceptable commercial terms, (b) the approval of an Environmental Impact Assessment and (c) receiving regulatory and partner consents to drill; and securing funds for drilling. Failure to achieve any one of these objectives could materially limit the commercial opportunity for the business development growth potential.

2) Commercial success in Guercif may also be dependent upon securing a market for any discovered gas either within Morocco or exported through the Maghreb gas pipeline to Europe. There is a risk that the Company may not be able to access pipeline infrastructure to transport gas to markets due either to technical considerations, capacity constraints or a failure to agree acceptable tariff terms for use of the third-party infrastructure. In such circumstances, the business growth strategy of the Company could be constrained by lack of a gas market and inability to access gas infrastructure.

Trinidad

3) Receipt of the Company's share of potential profits under the Well Participation Agreement ("**WPA**") from the 2019 CO2 EOR Project is dependent upon FRAM Exploration (Trinidad) Ltd. ("**FRAM**"), a wholly-owned subsidiary of Columbus Energy Resources Plc ("**Columbus**"), paying to the Company its agreed share of the CO2 EOR operating profits, after deduction of taxes, in a timely manner and in accordance with the commercial terms of the WPA.

4) Potential future production from the CO2 EOR Pilot Project operations (from which the Company derives its share of operating profits) is attributable under the IPSC to enhanced oil production relative to a base line profile established by FRAM and Heritage Petroleum Trinidad Ltd. ("**Heritage**") for only the wells currently producing that form part of the CO2 EOR Pilot Project. The Company will only receive profits from enhanced oil production attributable to the CO2 EOR Pilot Project operations. As such, the Company is dependent upon verifying the production rates and base line profile with the operator FRAM to determine its share of profits from the production. There is a risk that enhanced oil production from the CO2 EOR Pilot Project will not be achieved for technical and geological reasons and therefore under those circumstances the Company will not generate profits under the WPA from the production.

5) Under the WPA terms, the Company has until 30 September 2020 an exclusive right to acquire FRAM for an agreed cash consideration, subject to all regulatory approvals and consents. There is a risk that the Company fails to proceed to acquire FRAM due to technical reasons, if the CO2 EOR Pilot Project fails to deliver enhanced oil production and the Company's share of profits; CO2 cannot be injected as currently envisaged; lack of access to financial resources to complete an acquisition; and/or failure to receive regulatory approvals and consents for the acquisition which may take into account in-country sensitivities regarding ownership of natural resources. In such circumstances the Company will only continue to receive its share of profits from the CO2 EOR production under the WPA but will not have any rights to actual production or attributable resources to the remainder of the Inniss-Trinity oil field not covered by the CO2 EOR Pilot Project, as would be the case if an acquisition of FRAM were to proceed.

6) Profits potentially received by the Company from CO2 EOR production are calculated in accordance with the commercial terms of the WPA between FRAM and Predator Oil & Gas Trinidad Ltd. ("**POGT**"). Under FRAM's Incremental Production Services Contract ("**IPSC**") for the Inniss-Trinity oil field with Heritage, the licence holder, FRAM is the operator of the field. Revenues from enhanced oil production operations are paid directly to FRAM by Heritage in Trinidad and Tobago dollars ("**TT$**"). Operating and capital costs are also expended in TT$. The TT$ is tied to the USD and therefore there is an additional currency exchange rate risk related to depreciation of the value of the USD.

7) There is a risk that repatriation of the Company's net share of profits in USD from CO2 EOR operations in Trinidad under the WPA may be irregular and delayed if there is a shortage of available USD in the Trinidad and Tobago banking system for conversion of TT$.

8) The profitability of the CO2 EOR Project is substantially dependent upon negotiating favourable commercial terms with Massy for the initial volumes of carbon dioxide required to enhance existing oil production in the well or wells selected to test the potential for the application of this different technology in Inniss-Trinity.

9) The ability to upscale profits from CO2 EOR production in accordance with its business development strategy, in the event of a successful CO2 EOR Pilot Project, is dependent on: (a) the Company being able to finance an acquisition of FRAM and (b) Heritage receiving MEEI consent to proceed with the CO2 EOR Pilot Project. Failure to achieve any one of these objectives could materially limit the commercial opportunity for the business development growth potential.

10) Unconventional methods of recovery and production enhancement (often of particular importance in the context of fields in the later stages of their productive life and particularly significant in the context of the Group's CO2 EOR Pilot Project in Trinidad) can be more expensive than conventional methods of production from fields in the initial stages of their productive lives. This could materially and adversely affect the Group's commercial viability and long-term growth prospects. If the global economic environment experiences a substantial downturn or remains relatively weak for the medium to long term, the ability of the Company to grow or maintain revenues in future years may be adversely affected, and at certain long-term price levels for oil, production operations requiring large volumes of injected CO2 may become too expensive and may not be economically viable. The Trinidad fiscal regime imposes an 18% Supplemental Petroleum Tax on all oil production profits when the price of West Texas crude is between US$50.01/brl and US$90.00/brl, except that investment in CO2 EOR can be offset against profits. Under these circumstances a sustained oil price at just above US$50/brl materially reduces post-tax net operating revenues.

Ireland

11) Further development of the Licensing Options offshore Ireland is dependent upon the Company obtaining successor authorisations, which were applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018. The grant of successor authorisations is conditional on the Company demonstrating, either by itself or with the addition of potential farm-in partners, a financial and technical operating capability to perform its exploration work obligations to be negotiated under the terms of any successor authorisations. No work programme has been committed to for the next 12 months and therefore the award of any successor authorisations will be dependent on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

    The precise details of the changing Government policy with respect to fossil fuel exploration remain to be announced. As a consequence, the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and finance necessary to commit to a work programme for any successor authorisation. Under these circumstances Ireland would not be progressed by the Company.

    In such circumstances it would be impossible to execute the Company's business development strategy, focussed on gas, for Ireland.

12) The Company's business development strategy for Ireland is based on the Company having an exclusive right to a successor authorisation in the case of its licensing options offshore Ireland, but the Company's commercial model has determined that the future funding of the development of these assets is undertaken by a third party or farm-in partner through a merger and consolidation of the assets in combination to create synergies with an acquisition of an interest in the producing Corrib gas field. There is a risk that an agreement with a third party or farm-in partner capable of executing the Company's business funding strategy for its Irish assets cannot be concluded within the period during which the Company's applications for successor authorisations, which have been applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018, are being processed by the Irish government. Under this scenario, no successor authorisations would be awarded and the Company's commercial model for funding would not therefore apply. This risk is heightened by the fact that Ireland now presents an extremely challenging investment case for the Company and for any potential partners given the level of uncertainty regarding the government's changing policy on fossil fuel exploration.

Regulatory and environmental risks

1) Existing and proposed legislation and regulation affecting greenhouse gas emissions may adversely affect the Company's business development strategy and the Company's operations.

    Failure to comply with existing legislation or any future legislation could adversely affect the Company's profitability if its business has material greenhouse gas intensive assets. 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.

Ireland

2) In Ireland, the Group is particularly exposed to the issue of CO2 emissions in the context of the fossil fuel industry. The Bill was proposed to limit the scope of the Petroleum and Other Minerals Development Act in respect of the issue of new licences for exploration and extraction of fossil fuels in Ireland. The precise details of the changing government policy with respect to fossil fuel exploration remain to be announced. As a consequence, the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and the finance necessary to commit to a work programme for any successor authorisations, which have been applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018. Under these circumstances, Ireland would not be progressed by the Company.

SUBSURFACE OBJECTIVES

The success of the business relies on accurate and detailed analysis of the subsurface based on subjective experience, expertise and desk-top models and studies. This can be impacted by poor quality data, either historical or recently gathered, and limited coverage. General information provided by external third party sources may not be accurate.

Subsurface technical risks specific to the Company's business operations are identified as follows:

Morocco

1) In the immediate area of focus, which is the Moulouya_1 Prospect, the 2D seismic database is sparse and the quality and completeness of the wireline well logs in old offset wells pertinent to understanding the geology of the GRF-1 and MSD-1 wells is poor.

2) Seismic ties to the aforementioned wells are imprecise. Prognosed formation tops for new exploration wells will therefore carry an element of uncertainty until modern velocity logs are run.

3) The interval of initial geological focus for the Company is the Tertiary (Tortonian and Messinian). Historical drilling has concentrated on the Jurassic prospectivity of the area with the result that sparse drilling was targeted to test only Jurassic highs, where the Tertiary section is thin and may not be representative of the prospective section in the Mouloutya_1 Prospect, which is developed in the deepest Tertiary basin. There is therefore a risk that the seismic interpretation for the presence of good quality, thicker reservoirs compared to those encountered in the GRF-1 and MSD-1 wells may be incorrect in the absence of validating well data.

4) Minor dry gas shows encountered in offset wells MSD-1 and GRF-1 occur in the Tertiary section as demonstrated by mud logs and wireline logs for MSD-1 and GRF-1, as interpreted by the previous operator TransAtlantic Petroleum Ltd. The interpreted gas intervals hows have not been verified by drill stem tests or pressure data and therefore the presence of gas in commercial quantities in the Guercif Licence is not yet proven.

5) GRF-1 provides evidence for significant over-pressuring of some potential reservoirs which will have to be taken into consideration for the purposes of safe well planning.

6) The existing sparse 2D seismic data demonstrate the presence of seismic amplitude anomalies. There is a risk that these may not be related to the presence of gas reservoirs or the presence of gas in commercial quantities.

Trinidad

7) The proposed Enhanced Oil Recovery uses carbon dioxide injection for a CO2 EOR Pilot Project in the AT-4 Block of the Inniss-Trinity oil field onshore Trinidad. The condition of the old production wells has to be ascertained first to determine if they are suitable to withstand being injected at high pressures with CO2. In addition, potential downhole obstacles must be identified so as to ensure that these do not obstruct sands that are suitable for CO2 injection. If the condition of the wells used for CO2 injection dictate that they lack the stability and casing integrity to withstand the proposed injection pressures then the design of the CO2 EOR Pilot Project may have to be reconsidered resulting in delays and increased technical challenges.

8) The effectiveness of CO2 EOR relies upon maintaining the CO2 as a supercritical fluid above its critical temperature (304.25 K, 31.10 °C, 87.98 °F) and critical pressure (72.9 atm, 7.39 MPa, 1,071 psi, 73.9 bar), in the well bore at the reservoir level, allowing it to expand to fill a reservoir like a gas but with a density like that of a liquid which facilitates gravity separation of water, oil, gas and CO2 in steeply dipping reservoirs. There is a risk that the required pressure may not be achievable due to poor well bore conditions and therefore the CO2 injection and oil sweep efficiency becomes less effective.

9) CO2 injection and flooding of a reservoir can significantly cause asphaltene deposition, which leads to serious production problems such as wettability alteration, the tendency of one fluid to spread on, or adhere to, a solid surface, plugging of the reservoir formation and blocking of flow lines. Asphaltene deposition increases with increasing pressure. Unless controlled, there is a risk that increasing pressure build-up cannot be controlled without the wells being shut in with loss of production.

10) CO2 is weakly acidic when mixed with water and is therefore potentially corrosive in the longer term. Infrastructure and well equipment may be damaged over a longer period of time if materials susceptible to corrosion are not replaced by resistant materials. The rate of corrosion is difficult to predict and there may be an earlier impact on the facilities than is currently considered to be the case.

Ireland

Licensing Option 16/26 Corrib South

11) For the Corrib South Licensing Option 16/26 the historical 3D seismic quality is of poor quality and the coverage is insufficient to confirm the south-western extent of the maximum case potential closure of the Corrib South prospect (the "**Corrib South Prospect**").

12) 2D seismic data over the southern extent of the Corrib South Prospect is sparse and of very poor quality.

Licensing Option 16/30 Ram Head ("**Ram Head**")

13) For Ram Head, no 3D seismic data exists over the area of the Ram Head Marathon 49/19-1 gas discovery. 2D seismic data coverage is extensive but of many different vintages. It is of poor to moderate data quality. This creates a risk in terms of verifying the extent of the closure for the Ram Head prospect (the "**Ram Head Prospect**").

14) Reservoir quality of the gas-bearing Middle and Upper Jurassic sands discovered in 49/19-1 is a significant risk based on historical data and given that the well was not tested at the time of the gas discovery. Potential commercial flow rates therefore have not been established.

15) There is potential, in the absence of pressure data for 49/19-1, for multiple gas-water contacts that could significantly limit the potential size of the original gas discovery and adversely impact gas flow rates.

COMMERCIAL MODELS

Morocco

1) Defining the presence of gas in material volumes in the area of the Guercif Petroleum Agreement is dependent upon drilling success to confirm the pre-drill forecasts of the anticipated geology and presence of a petroleum system, which can only be interpreted pre-drill by trendology and offset wells that were not optimally located to investigate the current focus of the exploration objectives. The commercial model for gas can only be validated once drilling confirms (or not as the case may be) the volume of gas in any prospect to be drilled.

2) The commercial success of an initial exploratory well may depend upon the results of a follow-up appraisal well, which will require an additional source of financing. The number of potential appraisal and development wells may impact the commercial models for developing gas in the Guercif Licence.

3) In the event that an exploration project is unsuccessful or an appraisal well proves the prospect to be uneconomic to develop, the value of the Company's business and any associated exploration licences may be diminished.

4) Exploration and production expenditure estimates are based on certain assumptions with respect to the method and timing of activities. By their nature, these estimates and assumptions are subject to significant uncertainties and, accordingly, the actual costs may materially differ from estimates and assumptions. In such circumstances this will potentially materially impact commercial models.

5) Commercial success may also be dependent upon securing a market for any discovered gas either within Morocco or exported through the Maghreb gas pipeline to Europe. There is a risk that the Company may not be able to access pipeline infrastructure to transport gas to markets due either to technical considerations, capacity constraints or a failure to agree acceptable tariff terms for use of the third-party infrastructure. The commercial model for developing gas is currently dependent on gaining access to the Maghreb gas pipeline.

6) In the event of a small gas discovery the ability to add new domestic gas users may require significant investment in a local gas-gathering infrastructure which could impact the profitability of any proposed gas development project. Sustaining local gas sales in the event of a small gas discovery under the terms of a gas sales agreement may require additional drilling success to maintain the quantum of gas agreed to be delivered under such gas sales agreements.

7) In the event of a large gas discovery the end user for the gas is likely to be a gas-fired power station. In this scenario additional appraisal drilling prior to a development decision, requiring additional sources of financing, may be required in order to satisfy the terms agreed in a gas sales agreement with such an end-user in the case where a minimum contracted volume of gas is agreed to be delivered over a longer term.

If gas is delivered in larger volumes for power generation then the gas sales price is anticipated to be tied to the spot price for Brent crude oil, rather than set by the Moroccan government as is currently the case for locally delivered gas supplies. Therefore, there is a risk that fluctuations in gas prices under these circumstances may adversely impact the profitability of the project and the commercial modelling.

Trinidad

8) Forecast production rates for CO2 EOR and therefore the levels of profits attributable to the Company under the WPA from such production rely on desktop calculations and have not been tested by CO2 EOR operations. There are no offset production wells producing from CO2 EOR operations to calibrate the desk-top models that have been calculated using theoretical material balance reservoir engineering equations. The success of the CO2 EOR Project and its commercial model is dependent therefore on a comparison of the actual operational results versus the pre-injection desk-top forecasts.

9) The volumes of CO2 required to be injected to increase reservoir pressure from its currently low level in order to enhance oil production have been estimated using desktop models that have been calculated using theoretical material balance reservoir engineering equations. These models assume limited vertical and lateral communication of the five Herrera reservoir sand intervals controlled by faulting and intervening shale seals. If this is not be the case then significantly more CO2 will be required to increase reservoir pressure and potentially enhance oil production should CO2 escape into other geological formations or adjacent fault compartments. The cost of the increased volume of CO2 required would impact the commercial models for the CO2 EOR Pilot Project.

10) The volume of CO2 to be injected has also been estimated on the basis of the remaining volume of oil in place in the reservoirs based upon historical estimates made by other operators. If this volume has been under-estimated, then the volume of CO2 required for injection will be larger, the costs higher and the commercial model less attractive.

11) In the event additional volumes of CO2 are required then the time to restore pressure in the reservoirs to facilitate natural flow will be longer than currently calculated using reservoir engineering desk-top calculations and as a consequence the date of first enhanced oil production could be significantly delayed. This will impact the time required for the CO2 EOR Pilot Project to potentially become commercial.

Ireland

12) Commercial models are dependent upon securing a market for any discovered or appraised gas in Licensing Options 16/26 and 16/30 either within Ireland or exported through the UK-Ireland gas Interconnectors to Europe. There is a risk that the Company may not be able to access pipeline infrastructure at the Corrib gas field and that the Kinsale gas pipeline to shore will be abandoned and decommissioned. Transport of gas to markets through such infrastructure may also be precluded due either to technical considerations, capacity constraints or a failure to agree acceptable tariff terms for use of the third-party infrastructure.

The commercial model for developing gas is currently dependent on gaining access to the existing infrastructure.

13) The Company's commercial model for Ireland requires finding suitable industry entities with an interest in developing a gas business in Ireland and who recognise the potential commercial synergies created by acquiring and developing the Company's assets to utilise existing gas infrastructure. Failure to find such entities as farm-in partners during the consideration by the regulatory authorities of the Company's applications for successor authorisations, which were applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018, would determine that the commercial model was not sustainable as no work programme is being offered over the next 12 months to effect the award of the successor authorisations without having access to additional financial resources and technical operating capabilities.

Other commercial model risks

14) The Company's functional and presentational currency is GBP. As a result, the Company's consolidated financial statements will carry the Company's assets in GBP. The Company conducts operations and make sales in currencies other than GBP. When consolidating a business that has functional currencies other than GBP, the Company will be required to translate, amongst other things, the balance sheet and operational results of such business into GBP. Due to the foregoing, changes in exchange rates between GBP and other currencies could lead to significant changes in the Company's reported financial results from period to period. Among the factors that may affect currency values are trade balances, levels of short-term interest rates, differences in relative values of similar assets in different currencies, long-term opportunities for investment and capital appreciation and political or regulatory developments. Although the Company may seek to manage its foreign exchange exposure, including by active use of hedging and derivative instruments, there is no assurance that such arrangements will be entered into or available at all times when the Company wishes to use them or that they will be sufficient to cover the risk.

REGULATORY AND ENVIRONMENTAL MATTERS

The specific material risks identified are as follows*:*

Morocco

1) The Group has received all regulatory consents and approvals required to maintain the Guercif Licence in full force and effect. The environmental impact assessment ("**EIA**") for the drilling of the Moulouya_1 Prospect was approved on 12 December 2019 at a meeting of the Comité National des Etudes d'Impact ("**CNEI**"), a department of the MEME. Accordingly official notification to the Company of the approval together with the programme of environmental surveillance and monitoring will be sent to the Company shortly. In the event that the Group may seek to farm out during the initial exploration period of the Guercif Licence, regulatory approval and consent would be required.

Trinidad

2) The Group is dependent on the operator FRAM to negotiate the terms of its IPSC with Heritage, the holder of the Inniss-Trinity licence. The Group entered into a WPA with FRAM whereby the Group provides investment and technical expertise for a CO2 EOR Pilot Project in the Inniss-Trinity Field in return for a one hundred per cent. (100%) recovery of investment prior to sharing post-tax operating profits from CO2 EOR Pilot Project production equally with FRAM. The

survival of the WPA after 31 December 2021 is dependent upon FRAM negotiating with Heritage a new extension to the current two-year extension term of its IPSC based on successful CO2 EOR Pilot Project results. There is a risk that FRAM fails to extend again the term of its IPSC by 31 December 2021 and consequently the WPA terminates and no further potential for profits from CO2 EOR production will be available to the Group.

3) The Company is dependent on a third party (FRAM) receiving regulatory approvals from the Ministry of Energy and Energy Industries ("**MEEI**") for the Carbon Dioxide Enhanced Oil Recovery Project ("**CO2 EOR Project**") to be implemented in Inniss-Trinity. MEEI approval for the Pilot CO2 EOR Project was received by FRAM on 3 January 2020. Further approvals from MEEI would be required if the CO2 EOR Project were to be expanded at some future date into other areas of the Inniss-Trinity field.

4) The Group also has an exclusive option to acquire FRAM, exercisable at the Group's discretion before 30 September 2020. There is a risk that a change of control of FRAM, if an acquisition by the Company were to proceed, might not necessarily receive regulatory consent.

5) In the Inniss-Trinity field in Trinidad, the Group will be involved in handling CO2 in surface and subsurface operations. CO2 is poisonous in confined spaces. When mixed with water it is mildly acidic and can cause in the longer-term corrosion of oil field pipeline infrastructure and processing and collection tanks as well as certain subsurface well materials and surface well head fittings. CO2 in the groundwater can have an adverse impact on the quality of water in aquifers from which domestic and industrial water supplies are drawn.

6) The nature of the CO2 EOR operations in the Inniss-Trinity field in Trinidad in which the Group will be participating creates a heightened risk of accidents and fatalities, and the Group may be required to pay compensation or suspend operations as a result of such accidents or fatalities, which could have a material adverse effect on the Group's business, financial condition, results of operations and prospects.

Ireland

7) In Ireland, Ram Head Licensing Option 16/30 expired on 30 November 2019. The Group has applied for a successor authorisation, which in the case of Licensing Option 16/30 would be for a standard exploration licence ("**SEL**"). The SEL would involve making a substantial commitment to a work programme that potentially involves the acquisition of 3D seismic data and the re-entering of an existing well or the drilling of a new well. There is no guarantee that the Group would wish to take on this commitment nor that it would satisfy the criteria required by the regulatory authorities in Ireland for the Group to be able to demonstrate a financial and technical capability to perform its exploration work obligations under the terms of any successor authorisation. No work programme has been committed to for the next 12 months and therefore the award of any successor authorisations will be dependent primarily on attracting a farm-in partner to address the financial and technical operating capability. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

8) The Group has applied for a successor authorisation to Licensing Option 16/26 ("**Corrib South**") on the Atlantic Margin of Ireland close to the Corrib gas field, following its expiration on 30 June 2018. The successor authorisation would be a Frontier Exploration Licence ("**FEL**") and the work commitment would be for 3D seismic during the first phase of the FEL, if awarded and accepted by the Group. Currently the potential award of the FEL is dependent on the Group demonstrating a financial and technical capability to perform its exploration work obligations under the terms of any successor authorisations. No work programme is being committed to for the next 12 months and therefore the award of any successor authorisations will be dependent primarily on attracting a farm-in partner to address the financial and technical

operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

In relation to Licensing Options 16/26 and 16/30, the precise details of the changing Government policy with respect to fossil fuel exploration remain to be announced. As a consequence the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and finance necessary to commit to a work programme for any successor authorisation, which have been applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018. Under these circumstances, Ireland would not be progressed by the Company.

INTERNAL CONTROL RISKS

The Company faces risks frequently encountered by developing companies such as limited resources. In particular, its future growth and prospects will depend on its ability to manage realistic growth expectations 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, or failure 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 its business, financial condition and results of operations.

The Board is experienced in the oil and gas business and is responsible for approving business development strategy, material operational commitments and decisions, financial planning and annual budgets. The management team provides consultancy services in relation to subsurface operations and technical matters and financial planning and cost control, supplemented where necessary by using experienced third party service providers and specialist consultants. There is a high level of communication between the Board and the management team, including regular operational updates and weekly cash reconciliations to address adequacy of working capital for the purposes of financial planning, such that variances from the operational and financial plans and forecasts can be identified early and, where necessary, appropriate corrective action can be applied.

The Board and management review exploration results and operational outcomes as the basis for decisions regarding future ongoing expenditure commitments and has appropriate resources, experience and expertise in the oil and gas sector appropriate for a small-cap company and operator.

Due to the international nature of the business there are, at times, significant and volatile foreign exchange rate movement exposures which the Company's internal reporting may not always be able to capture expeditiously through currency hedging arrangements. Current internal procedures regularly monitor exchange rate fluctuations such that significant exchange rate losses can be obviated.

Cash flow forecasting is done at the 'required currency' level and foreign currency balances are maintained to meet expected requirements but, from time to time, given finite cash resources expected requirements may be mistimed resulting in over and under exposures in specific currencies.

All the Company's disbursements are handled exclusively by the Company's administrative service provider. The Company maintains a strict procedure whereby the administrative service provider requires email authority from an executive director before any payments can be made or any inter-account transfers can be enacted. Each approved transaction is meticulously recorded and referenced for audit purposes.

OTHER RISKS

Loss of key management personnel

The Group's success depends upon skilled management as well as technical and administrative back-up. The loss of service of critical members of the Group's team could have an adverse effect on the business.

Circumstances could arise in the future whereby one or more of the Directors may allocate their time to other businesses leading to potential conflicts of interest in their determination as to how much time to devote in excess of their contractual obligations to the Company's affairs, which could have a negative impact on the Company's ability to carry on its business and/or to complete further acquisitions.

As of the date of this Document, each of the Directors has other private interests and duties, which include in the case of Dr Stephen Staley, directorships of other upstream oil and gas companies and, in the case of Paul Griffiths, a pre-IPO beneficial interest in a joint venture partner in the Irish Licensing Options. The Directors' other interests and duties do not give rise to any conflict of interest at present, but it is not possible to say whether any such conflict of interest will arise in the future or not given the strategies and goals of the Company and the other companies in which each of the Directors has other private interests and duties. Having an independent Non-Executive Director Chairman, with a casting vote at Board meetings, will ensure any such future potential conflicts of interest are dealt with independently and appropriately.

The Company is dependent on the executive Directors to identify potential business and licence acquisition opportunities in Trinidad, Morocco and Ireland and to oversee and execute its oil and gas operations. The loss of services of the Directors (in particular the executive Directors) could materially adversely affect it.

Risks related to a Standard Listing

There are risks relating to the Ordinary Shares where the Standard Listing affords investors a lower level of regulatory protection than a Premium Listing, which is subject to additional obligations under the Listing Rules.

The Company's Standard Listing does not require it to comply with the provisions of, amongst other things:

- Chapter 8 of the Listing Rules regarding the appointment of a sponsor to guide the Company in understanding and meeting its responsibilities under the Listing Rules in connection with certain matters. The Company has not and does not intend to appoint such a sponsor in connection with the Placing and Admission;
- Chapter 9 of the Listing Rules relating to continuing obligations;
- Chapter 10 of the Listing Rules relating to significant transactions;

- Chapter 11 of the Listing Rules regarding related party transactions. Nevertheless, the Company will not enter into any transaction which would constitute a 'related party transaction' as defined in Chapter 11 of the Listing Rules without the specific prior approval of a majority of the Directors;

- Chapter 12 of the Listing Rules regarding purchases by the Company of its Ordinary Shares; and

- Chapter 13 of the Listing Rules regarding the form and content of circulars to be sent to Shareholders.

Risks related to the Ordinary Shares

1. The price of the Ordinary Shares after the Placing can vary due to a number of factors, including but not limited to, general economic conditions and forecasts, the Company's general business condition and the release of its financial reports. Although the Company's current intention is that its securities should continue to trade on the London Stock Exchange, it cannot assure investors that it will always do so. In addition, an active trading market in the future of the Ordinary Shares may not be maintained. Investors may be unable to sell their Ordinary Shares unless a market can be maintained, and if the Company subsequently gains a listing on an exchange in addition to, or in lieu of, the London Stock Exchange, the level of liquidity of the Ordinary Shares may decline.

2. Investors may not be able to realise returns on their investment in Ordinary Shares within a period that they would consider to be reasonable.

   Investments in Ordinary Shares may be relatively illiquid. There may be a limited number of Shareholders and this factor, together with the number of Ordinary Shares to be issued pursuant to the Placing, may contribute both to infrequent trading in the Ordinary Shares on the London Stock Exchange and to volatile Ordinary Share price movements. Investors should not expect that they will necessarily be able to realise their investment in Ordinary Shares within a period that they would regard as reasonable. Accordingly, the Ordinary Shares may not be suitable for short-term investment. Even if an active trading market develops, the market price for the Ordinary Shares may fall below the Placing Price.

Risk of suspension

POGV may wish to exercise its option to complete the Potential FRAM Acquisition, in which event the acquisition could be treated as a Reverse Takeover depending on the materiality of the potential transaction at the time. There is no certainty that the Company will decide, or be able, to complete the Potential FRAM Acquisition, and no certainty on whether the transaction would be a Reverse Takeover.

Should a Reverse Takeover be announced by the Company or knowledge of the same leak into the market then the listing of the Ordinary Shares may be suspended. During a period of suspension Shareholders may be unable to realise the value from their Ordinary Shares. Should the Ordinary Shares remain suspended for a prolonged period, such suspension may adversely affect the value of the shares.

It is the Directors' duty under the Listing Rules to contact the FCA as early as possible if a Reverse Takeover has been agreed or is in contemplation, to discuss whether a suspension of the Company's listing is appropriate. The FCA retains a general power to suspend a company's securities where it considers it necessary to protect its investors. The FCA may decide to exercise such power where a company undertakes a transaction which, because of the comparative size of the company and any target would be a Reverse Takeover under the Listing Rules.

The Listing Rules provide generally that when a Reverse Takeover is announced or leaked, there will be insufficient information in the market about the proposed transaction and the listed company will be unable to assess accurately its financial position and inform the market appropriately, so suspension of trading in the listed company's securities will often be appropriate.

Any such suspension would be likely to continue until sufficient financial information on the transaction is made public and the period during which the Ordinary Shares would be suspended may therefore be significant.

Depending on the nature of such acquisition and the stage at which it is leaked or announced it may take a substantial period of time to compile the relevant information, particularly where a target does not have financial or other information readily available which is comparable with the information a listed company would be expected to provide. A suspension of the Ordinary Shares would materially reduce liquidity in the Ordinary Shares which may affect an investor's ability to realise some or all of his or her investment and/or the price at which such investor can effect such realisation. If the Company's listing has been suspended from trading for more than six months, the listing may be cancelled.

Generally, the Directors would expect the Company's listing to be cancelled on announcement of a Reverse Takeover and should the Company's shares not be re-admitted for trading then the liquidity and price of the Company's shares could be adversely affected.

If the FCA decided to cancel the Company's listing, the Company would expect to seek re-admission to listing at the time of completion of any such Reverse Takeover. The process for admission following a Reverse Takeover would require publication of a prospectus and it would be necessary for the Company to meet the eligibility requirements set by the FCA in order to be admitted. However, there is a risk that such eligibility criteria might not be met and therefore there is no certainty that such re-admission would be granted. A cancellation of the listing of the Ordinary Shares would materially reduce liquidity in the Ordinary Shares which may affect a Shareholder's ability to realise some or all of his or her investment and/or the price at which such Shareholder can effect such realisation.

Risks related to taxation

Taxation of returns from assets located outside of the UK may reduce any net return to investors.

To the extent that any assets or business which the Company acquires is or are established outside the UK, it is possible that any return the Company receives from it may be reduced by irrecoverable foreign withholding or other local taxes and this may reduce any net return derived by investors from a shareholding in the Company.

The tax treatment of Shareholders, any special purpose vehicle that the Company may establish and any company which the Company may acquire are all subject to changes in tax laws or practices in England and Wales or any other relevant jurisdiction. Any change may reduce any net return derived by investors from a shareholding in the Company.

Investors should not rely on the general guide to taxation set out in this Document and should seek their own specialist advice. The tax rates referred to in this Document are those currently applicable and they are subject to change.

The Company has and will continue to structure the Group, including any asset, company or business acquired, to maximise returns for Shareholders in as fiscally efficient a manner as is

practicable. The Company has made certain assumptions regarding taxation. However, if these assumptions are not correct, taxes may be imposed with respect to the Company's assets, or the Company may be subject to tax on its income, profits, gains or distributions (either on a liquidation and dissolution or otherwise) in a particular jurisdiction or jurisdictions in excess of taxes that were anticipated. This could alter the post-tax returns for Shareholders (or Shareholders in certain jurisdictions). The level of return for Shareholders may also be adversely affected. Any change in laws or tax authority practices could also adversely affect any post-tax returns of capital to Shareholders or payments of dividends (if any, which the Company does not envisage the payment of, at least in the short to medium term). In addition, the Company may incur costs in taking steps to mitigate any such adverse effect on the post-tax returns for Shareholders.

Risks related to Jersey company law

The Company is a company incorporated in Jersey. Accordingly, UK legislation regulating the operations of companies does not generally apply to the Company. In addition, the laws of Jersey apply with respect to the Company and these laws provide rights, obligations, mechanisms and procedures that do not apply to companies incorporated in the UK. As the rights of Shareholders are governed by Jersey law and the Articles, these rights differ in certain respects from the rights of shareholders in the UK and other jurisdictions.

Risks related to changes in tax residency

The Company is exposed to changes in its tax residency and changes in the tax treatment or arrangements relating to its business and its UK resident investors are exposed to its continued compliance with the UK Offshore Funds Regulations.

Whilst the Company is incorporated in Jersey, it must pay continued attention to ensure that it remains resident for tax purposes in Jersey (and not in the UK) at all times. Should the Company be considered to be a tax resident, for example, it will be subject to UK corporation tax on its worldwide income and gains with the result that investors stand to suffer significant tax leakage indirectly.

To maintain its Jersey tax residency, the Company must be centrally managed and controlled in Jersey (and outside the UK) at all times. Central management and control, which broadly seeks to determine who exercises ultimate decision-making authority over a company's affairs and where they exercise that authority from, typically resides at board level, unless the decision-making authority of a board is being usurped.

The composition of the Board, including each individual Director's experience and place of residence are important factors in establishing that ultimate decision-making authority over the Company's affairs resides with the Board. It is imperative that the Board is also capable of demonstrating having exercised its authority during fully quorate Board meetings held regularly in Jersey.

In addition, if the Company was treated as being engaged in a trade or business (whether through a permanent establishment or otherwise) in any country in which it invests or in which its investments are managed, all of its income or gains, or the part of such income or gains that is attributable to, or effectively connected with, such trade or business may be subject to tax in that country, which could have a material adverse effect on the Company's performance and the value of the Ordinary Shares.

UK tax resident investors should also be aware that to preserve capital gains tax treatment on the disposal of their shares, the Company must comply with the Offshore Funds Regulations to the extent they apply to the Company, which may include reporting distributions, including deemed distributions, to investors during each relevant reporting period in order that investors can meet their respective UK tax liabilities accordingly.

The risks noted above do not necessarily comprise all those faced by the Group. There may be special risks for investors in certain jurisdictions holding Ordinary Shares. At this time, the Company does not intend to make accommodations regarding its financial information to assist any holders with their tax obligations.

An investment in Ordinary Shares is speculative and may not be suitable for all recipients of this Document. Potential UK investors are accordingly advised to consult a person authorised under the FSMA who specialises in advising in investments of this kind before making any investment decisions. Non-UK investors are advised to consult another appropriately authorised independent adviser who specialises in advising on the acquisition of shares and other securities. A prospective investor should consider carefully whether an investment in the Company is suitable in the light of their personal circumstances and the financial resources available to them.

PART III
CONSEQUENCES OF A STANDARD LISTING

Application will be made for the New Ordinary Shares to be admitted to listing on the Official List pursuant to Chapter 14 of the Listing Rules, which sets out the requirements for Standard Listings. As well as the provisions of Chapter 14 of the Listing Rules, Listing Principles 1 and 2 (as set out in Listing Rule 7.2.1) apply to the Company.

In addition, while the Company has a Standard Listing, it is not required to comply with the provisions of, among other things:

- Chapter 8 of the Listing Rules regarding the appointment of a sponsor to guide the Company in understanding and meeting its responsibilities under the Listing Rules in connection with certain matters. The Company has not and does not intend to appoint such a sponsor in connection with the Placing;
- Chapter 9 of the Listing Rules regarding continuous obligations for a company with a Premium Listing;
- Chapter 10 of the Listing Rules relating to significant transactions. It should be noted therefore that acquisitions will not require specific Shareholder consent, even if Ordinary Shares are being issued as consideration;
- Chapter 11 of the Listing Rules regarding related party transactions;
- Chapter 12 of the Listing Rules regarding purchases by the Company of its Ordinary Shares; and
- Chapter 13 of the Listing Rules regarding the form and content of circulars to be sent to Shareholders.

The Company is not currently eligible for a Premium Listing under Chapter 6 of the Listing Rules. The Directors may in the future seek to transfer the Company from a Standard Listing to either a Premium Listing or other appropriate listing venue, although there can be no guarantee that the Company will fulfil the relevant eligibility criteria at the time or that a transfer to a Premium Listing or other appropriate stock market will be achieved. If a transfer to a Premium Listing is possible (and there can be no guarantee that it will be) and the Company decides to transfer to a Premium Listing, the various Listing Rules highlighted above as rules with which the Company is not currently required to comply will become mandatory and the Company will be required to comply with the continuing obligations contained within the Listing Rules (and the Disclosure Guidance and Transparency Rules) in the same manner as any other company with a Premium Listing.

It should be noted that the FCA will not have the authority to (and will not) monitor the Company's compliance with any of the Listing Rules which the Company has indicated herein that it intends to comply with on a voluntary basis, nor to impose sanctions in respect of any failure by the Company so to comply. However, the FCA would be able to impose sanctions for non-compliance where the statements regarding compliance in this Document are themselves misleading, false or deceptive.

PART IV
IMPORTANT INFORMATION

In deciding whether or not to invest in New Ordinary Shares, prospective Investors should rely only on the information contained in this Document. No person has been authorised to give any information or make any representations other than as contained in this Document and, if given or made, such information or representations must not be relied on as having been authorised by the Company or the Directors. Without prejudice to the Company's obligations under the FSMA, the Prospectus Regulation Rules, Listing Rules and Disclosure Guidance and Transparency Rules, neither the delivery of this Document nor any subscription made under this Document shall, under any circumstances, create any implication that there has been no change in the affairs of the Company since the date of this Document or that the information contained herein is correct as at any time after its date.

Prospective Investors must not treat the contents of this Document or any subsequent communications from the Company or the Directors, or any of their respective affiliates, officers, directors, employees or agents as advice relating to legal, taxation, accounting, regulatory, investment or any other matters.

The section headed "Summary" should be read as an introduction to this Document. Any decision to invest in the New Ordinary Shares should be based on consideration of this Document as a whole by the Investor. In particular, Investors must read the section headed "What are the key risks that are specific to the issuer?" of the Summary, together with the risks set out in the section headed "Risk Factors" beginning on page 13 of this Document.

This Document is being furnished by the Company in connection with an offering exempt from registration under the Securities Act solely to enable prospective Investors to consider the purchase of the New Ordinary Shares. Any reproduction or distribution of this Document, in whole or in part, and any disclosure of its contents or use of any information herein for any purpose other than considering an investment in the New Ordinary Shares offered hereby is prohibited. Each offeree of New Ordinary Shares, by accepting delivery of this Document, agrees to the foregoing.

This Document does not constitute, and may not be used for the purposes of, an offer to sell or an invitation or the solicitation of an offer or invitation to subscribe for or buy, any Ordinary Shares by any person in any jurisdiction: (i) in which such offer or invitation is not authorised; (ii) in which the person making such offer or invitation is not qualified to do so; or (iii) in which, or to any person to whom, it is unlawful to make such offer, solicitation or invitation. The distribution of this Document and the offering of the Ordinary Shares in certain jurisdictions may be restricted. Accordingly, persons outside the United Kingdom who obtain possession of this Document are required by the Company, and the Directors to inform themselves about, and to observe any restrictions as to the offer or sale of Ordinary Shares and the distribution of, this Document under the laws and regulations of any territory in connection with any applications for Ordinary Shares, including obtaining any requisite governmental or other consent and observing any other formality prescribed in such territory. No action has been taken or will be taken in any jurisdiction by the Company or the Directors, that would permit a public offering of the New Ordinary Shares in any jurisdiction where action for that purpose is required, nor has any such action been taken with respect to the possession or distribution of this Document other than in any jurisdiction where action for that purpose is required. Neither the Company, nor the Directors accepts any responsibility for any violation of any of these restrictions by any other person.

The New Ordinary Shares have not been and will not be registered under the Securities Act, or under any relevant securities laws of any state or other jurisdiction in the United States, or under the applicable securities laws of Australia, Canada, Japan or the Republic of South Africa. Subject to certain exceptions, the Ordinary Shares may not be, offered, sold, resold, reoffered, pledged, transferred, distributed or delivered, directly or indirectly, within, into or in the United States, Australia, Canada, Japan or the

Republic of South Africa or to any national, resident or citizen of Australia, Canada, Japan or the Republic of South Africa.

Data protection

The Company may delegate certain administrative functions in relation to the Company to third parties and will require such third parties to comply with data protection and regulatory requirements of any jurisdiction in which data processing occurs. Such information will be held and processed by the Company (or any third party, functionary or agent appointed by the Company) for the following purposes:

(a) verifying the identity of the prospective Investor to comply with statutory and regulatory requirements in relation to anti-money laundering procedures;

(b) carrying out the business of the Company and the administering of interests in the Company;

(c) meeting the legal, regulatory, reporting and/or financial obligations of the Company in the United Kingdom or elsewhere; and

(d) disclosing personal data to other functionaries of, or advisers to, the Company to operate and/or administer the Company.

Where appropriate it may be necessary for the Company (or any third party, functionary or agent appointed by the Company) to:

(a) disclose personal data to third party service providers, agents or functionaries appointed by the Company to provide services to prospective Investors; and

(b) transfer personal data outside of the EEA to countries or territories which do not offer the same level of protection for the rights and freedoms of prospective Investors as the United Kingdom.

If the Company (or any third party, functionary or agent appointed by the Company) discloses personal data to such a third party, agent or functionary and/or makes such a transfer of personal data it will use reasonable endeavours to ensure that any third party, agent or functionary to whom the relevant personal data is disclosed or transferred is contractually bound to provide an adequate level of protection in respect of such personal data.

In providing such personal data, Investors will be deemed to have agreed to the processing of such personal data in the manner described above. Prospective Investors are responsible for informing any third party individual to whom the personal data relates of the disclosure and use of such data in accordance with these provisions.

Selling and transfer restrictions

Prospective Investors should consider (to the extent relevant to them) the notices to residents of various countries set out in Part XV (*Notices to Investors*) of this Document.

Investment considerations

In making an investment decision, prospective Investors must rely on their own examination, analysis and enquiry of the Company, this Document and the terms of the Placing, including the merits and risks involved. The contents of this Document are not to be construed as advice relating to legal, financial, taxation, investment decisions or any other matter. Prospective Investors should inform themselves as to:

- the legal requirements within their own countries for the purchase, holding, transfer or other disposal of the Ordinary Shares;

- any foreign exchange restrictions applicable to the purchase, holding, transfer or other disposal of the Ordinary Shares which they might encounter; and

- 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 or distributions by the Company, either on a liquidation and distribution or otherwise. 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.

An investment in the Company should be regarded as a long-term investment. There can be no assurance that the Company's objective will be achieved.

It should be remembered that the price of the Ordinary Shares, and any income from such Ordinary Shares, can go down as well as up.

This Document should be read in its entirety before making any investment in the Ordinary Shares. All Shareholders are entitled to the benefit of, are bound by, and are deemed to have notice of, the provisions of the Articles of Association of the Company, which Investors should review.

Forward-looking statements

This Document includes statements that are, or may be deemed to be, "forward-looking statements". In some cases, these forward-looking statements can be identified by the use of forward-looking terminology, including the terms "targets", "believes", "estimates", "anticipates", "expects", "intends", "may", "will", "should" or, in each case, their negative or other variations or comparable terminology. They appear in a number of places throughout the Document and include statements regarding the intentions, beliefs or current expectations of the Company and the Board of Directors concerning, among other things: (i) the Company's objective, acquisition and financing strategies, results of operations, financial condition, capital resources, prospects, capital appreciation of the Ordinary Shares and dividends; and (ii) future deal flow and implementation of active management strategies, including with regard to any acquisitions. By their nature, forward-looking statements involve risks and uncertainties because they relate to events and depend on circumstances that may or may not occur in the future. Forward-looking statements are not guarantees of future performance. The Company's actual performance, results of operations, financial condition, distributions to shareholders and the development of its financing strategies may differ materially from the forward-looking statements contained in this Document. In addition, even if the Company's actual performance, results of operations, financial condition, distributions to shareholders and the development of its financing strategies are consistent with the forward-looking statements contained in this Document, those results or developments may not be indicative of results or developments in subsequent periods. Important factors that may cause these differences include, but are not limited to:

- the Company's ability to deploy the Net Placing Proceeds on a timely basis;

- the availability and cost of equity or debt capital;

- currency exchange rate fluctuations, as well as the success of the Company's hedging strategies in relation to such fluctuations (if such strategies are in fact used); and

- legislative and/or regulatory changes, including changes in taxation regimes.

Prospective Investors should carefully review the "Risk Factors" section of this Document for a discussion of additional factors that could cause the Company's actual results to differ materially, before making an investment decision. For the avoidance of doubt, nothing in this paragraph constitutes a qualification of the working capital statement contained in paragraph 10 of Part XIV (*Additional Information*).

Forward-looking statements contained in this Document apply only as at the date of this Document and do not in any way qualify the working capital statement contained in paragraph 10 of Part XIV (*Additional Information*). Subject to any obligations under the Listing Rules, the Disclosure Guidance and Transparency Rules, the Market Abuse Regulation and the Prospectus Regulation Rules, the Company undertakes no obligation publicly to update or review any forward-looking statement, whether as a result of new information, future developments or otherwise.

Market Data

Where information has been sourced from a third party, the Company and the Directors confirm that such information has been accurately reproduced and as far as they are aware and have been able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

Currency presentation

Unless otherwise indicated, all references to "**£**" or "**Pounds Sterling**" are to the lawful currency of the UK.

No incorporation of website

The contents of any website of the Company or any other person do not form part of this Document.

Definitions

A list of defined terms used in this Document is set out in Parts XVI (*Definitions*) and XVII (*Glossary*) of this Document.

PART V
EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Publication of this Document	19 February 2020
Admission and commencement of unconditional dealings in the New Ordinary Shares	8.00 a.m. on 28 February 2020
CREST members' accounts credited	8.00 a.m. on 28 February 2020

All references to time in this Document are to London, UK time unless otherwise stated and each of the times and dates are indicative only and may be subject to change.

PLACING STATISTICS

Number of Existing Ordinary Shares	108,172,169
Number of New Ordinary Shares in the Placing	89,000,000
Percentage of Enlarged Share Capital represented by the New Ordinary Shares	45.14%
Placing Price per New Ordinary Share	£0.04
Gross Proceeds	£3,560,000
Net Placing Proceeds	£3,305,000

DEALING CODES

The dealing codes for the Ordinary Shares will be as follows:

ISIN	JE00BFZ1D698
SEDOL	BFZ1D69
TIDM	PRD
LEI	213800L7QXFURBFLDS54

PART VI
DIRECTORS, AGENTS AND ADVISERS

Directors	Carl Kindinger (Non-Executive Chairman) Paul Stanard Griffiths (Executive Director – CEO) Ronald Pilbeam (Executive Director) Dr Stephen Staley (Non-Executive Director)
Company Secretary	OAK Group (Jersey) Limited 3rd Floor, Standard Bank House 47 – 49 La Motte Street Jersey JE2 4SZ
Registered Office	3rd Floor, Standard Bank House 47 – 49 La Motte Street Jersey JE2 4SZ
Telephone	+44 (0) 1534 834 600
Joint Brokers and Placing Agents	Novum Securities Limited 8-10 Grosvenor Gardens London SW1W 0DH Optiva Securities 49 Berkeley Square London W1J 5AZ
Auditors and Reporting Accountants	PKF Littlejohn LLP 15 Westferry Circus Canary Wharf London E14 4HD
Legal advisers to the Company as to English law	Charles Russell Speechlys LLP 5 Fleet Place London EC4M 7RD
Legal advisers to the Company as to Jersey law	Pinel Advocates 7 Castle Street St Helier Jersey JE2 3BT
Competent Person	SLR Consulting (Ireland) Ltd 7 Dundrum Business Park Windy Arbour Dublin 14, D14 N2Y7 Republic of Ireland
Registrar	Computershare Investor Services (Jersey) Limited Queensway House Hilgrove Street St Helier, Jersey JE1 1ES

Principal Bankers	The Royal Bank of Scotland International Limited P.O. Box 64 Royal Bank House 71 Bath Street St Helier Jersey JE4 8PJ Barclays Bank 39-41 Broad Street St. Helier Jersey JE4 8PU

PART VII
THE COMPANY'S STRATEGY

Introduction

The Company was incorporated on 19 December 2017 as a company with limited liability under the Companies (Jersey) Law 1991 (as amended) and with an indefinite life. The Company operates through three wholly-owned subsidiaries, all registered in Jersey:

1. **Predator Gas Ventures Ltd. ("PGV")**

   PGV operates onshore Morocco and holds a 75% working interest in the Guercif Licence and is partnered by ONHYM, the State oil company, which holds the remaining 25% and is carried through exploration but funds its pro-rata share of all costs upon a Declaration of Commerciality. The licence area's initial target for drilling is a gas prospect located approximately 4 kilometres away from the Maghreb gas pipeline.

2. **Predator Oil and Gas Ventures Ltd ("POGV")**

   POGV operates offshore the Republic of Ireland and holds:

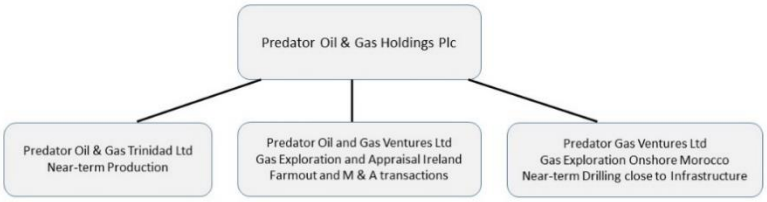
   2.1 a 50% working interest in and is operator of the Ram Head gas discovery (Licensing Option 16/30) made by Marathon Oil in 1984/5 and located in the North Celtic Sea Basin, approximately 75 km offshore from the current landfall of gas from the Kinsale field at Inch, County Cork; and

   2.2 a 50% working interest in and is operator of Corrib South (Licensing Option 16/26), located in the Atlantic Margin's Slyne Basin, approximately 70 km offshore from the current landfall of gas from the Corrib gas field in County Mayo. The Licensing Option is adjoining and to the south of the Vermillion-operated Corrib Gas Field, which is currently Ireland's largest producing gas field.

   In Ireland, the Group's Licensing Option 16/30 expired on 30 November 2019 and Licensing Option 16/26 expired on 30 June 2018. The Group has applied for successor authorisations, which are under consideration. No work programme has been committed to for the next 12 months and therefore the award of any successor authorisations will be dependent primarily on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

3. **Predator Oil & Gas Trinidad Ltd., ("POGT")**

   POGT has a non-operated Enhanced Oil Recovery Project using injected carbon dioxide ('**CO2 EOR**') to sequestrate quantities of the pollutant CO2 to enhance oil production onshore the Republic of Trinidad and Tobago. POGT is party to a Well Participation Agreement ("**WPA**") with FRAM Exploration (Trinidad) Ltd. ("**FRAM**"), the operator of an Incremental Production Service Contract ("**IPSC**") for a licence held by Heritage, relating to the producing Inniss-Trinity oil field ("**Inniss-Trinity**"). Under the terms of the WPA, POGT will fund the cost of a CO2 EOR Pilot Project in return for only profits from the sale of hydrocarbon production by FRAM to Heritage from the CO2 EOR Pilot Project once completed and in production.



Ref	Licence/Agreement	Issued	Asset	Operator	Partners	PRD%	Type
ONSHORE TRINIDAD							
1	Well Participation Agreement Production Revenue Split 100% until repayment of investment 50% after repayment of investment	2017	Inniss-Trinity Pilot C02 EOR	Fram Exploration (Trinidad) Ltd Predator Oil & Gas Trinidad Ltd (Technical Operator)	Fram Exploration (Trinidad) Ltd	100 (50)	Producing Oil Field Pilot C02 EOR
OFFSHORE IRELAND							
Atlantic Margin Slyne Basin							
2	LO 16/26	2016[1]	Corrib South	Predator Oil and Gas Ventures Ltd	Theseus Ltd.	50	Gas exploration
North Celtic Sea Basin							
3	LO 16/30	2016[2]	Ram Head	Predator Oil and Gas Ventures Ltd	Theseus Ltd.	50	Gas discoveries
ONSHORE MOROCCO							
4	Guercif Petroleum Agreement	2019	Moulouya	Predator Gas Ventures Ltd	ONHYM	75	Gas exploration

[1] *Frontier Exploration Licence applied for*
[2] *12 month extension to LO 16/30 applied for*

Ref	Licence/Agreement	Issued	Asset	Operator	Partners	PRD%	Type
ONSHORE TRINIDAD							
1	Well Participation Agreement Production Revenue Split 100% until repayment of investment 50% after repayment of investment	2017	Inniss-Trinity Pilot C02 EOR	Fram Exploration (Trinidad) Ltd Predator Oil & Gas Trinidad Ltd (Technical Operator)	Fram Exploration (Trinidad) Ltd	100 (50)	Producing Oil Field Pilot C02 EOR
OFFSHORE IRELAND							
Atlantic Margin Slyne Basin							
2	LO 16/26	2016[1]	Corrib South	Predator Oil and Gas Ventures Ltd	Theseus Ltd.	50	Gas exploration
North Celtic Sea Basin							
3	LO 16/30	2016[2]	Ram Head	Predator Oil and Gas Ventures Ltd	Theseus Ltd.	50	Gas discoveries
ONSHORE MOROCCO							
4	Guercif Petroleum Agreement	2019	Moulouya	Predator Gas Ventures Ltd	ONHYM	75	Gas exploration

[1] *Frontier Exploration Licence applied for*
[2] *12 month extension to LO 16/30 applied for*

Business Strategy

Operating and funding strategy

The Company is led by a small executive team who are all significant shareholders, motivated to deliver on strategic goals. The Company maintains a low overhead that is flexible through outsourcing administrative functions and engaging industry specific expertise on short term consultancy arrangements.

1. A guiding principle in raising equity for the Company is to seek funding for major capital expenditure, such as a higher risk and more costly exploration drilling programme, through farm-outs to industry peers or diluting equity interests in subsidiary entities. As an anti-dilution mechanism judicious levels of debt are resorted to as a supplement to equity fund raises where it is necessary to secure rights to certain exploration assets with high impact potential for shareholders.

2. Funding to support working capital and corporate overheads was raised at the initial listing of the Company. The Company is developing CO2 EOR opportunities in Trinidad which are structured to balance future working capital outflows required to expand CO2 EOR profits derived from production opportunities under the WPA contractual model, with net cash inflows from the current CO2 EOR Pilot Project in the event that it is successful.

3. The Company's strategy is not to pursue large scale projects, as the operator, into development phases. Rather than fund participation in the development of a project, the Company will seek to dilute down to a carried interest. The Company's preference is monetisation of a project on attractive terms prior to reaching a development phase.

4. Following realisation of value for Shareholders from the sale of project interests to third parties or the outright sale of the Company, The Company's current intention is to distribute free cash from its operational activities in Trinidad to Shareholders subject to the ongoing capex and working capital constraints necessary in relation to prudent financial management of its business operations and business development. The Company will only pay dividends to the extent that to do so is in accordance with the Jersey Companies Law and all other applicable laws. The Directors do not anticipate declaring any dividends in the short to medium term.

Rationale for establishing asset portfolio

The Company's portfolio of assets has been established based on an ethical and proactive response to the issue of climate change and the implications for the oil and gas sector. In this context the Company is focussed on developing an environmentally responsible fossil fuel business where its business approach can be demonstrated as contributing to a reduction in CO2 emissions. The Company is therefore targeting exploring for, appraising and developing gas prospects, as electricity generation from gas has a lower carbon footprint compared to that for oil and coal, and sequestrating currently vented CO2 in oil reservoirs for enhanced oil production.

Focus on near term gas opportunities

The Company has a policy of seeking near-term monetisation of its assets through establishing early production and revenue generation by: applying CO2 EOR technology in Trinidad to currently producing mature oil fields; exploring for, appraising and developing gas adjacent to existing infrastructure, so reducing the lead time to establish gas production; and by consolidating certain assets, including discovered gas, to provide a material portfolio of licence interests suitable for further more costly development by a larger business entity, requiring access to gas markets and gas trading opportunities.

Further material factors that are taken into consideration in developing the Company's business strategy include, but are not limited to:

- reducing exploration risk by applying geological analogies with nearby producing fields;
- minimising exploration and appraisal expenditures by concentrating on low cost onshore opportunities and utilising available in-country rigs;
- working closely with government regulators to demonstrate the potential environmental benefits of applying the Company's business activities in terms of reducing CO2 emissions by sequestrating CO2 and providing gas as an alternative to oil and coal for power generation;
- constructing robust project economic models based on attractive in-country commodity pricing and market access; and
- a fiscal regime that can be easily adapted to the Company's objective of early monetisation.

The Company has thus far relied on funds raised from the IPO and the CLN for the initial 18-month portfolio-building and licence acquisition stage. The CLN was acquired to finance a refundable bank guarantee to secure the onshore Moroccan Guercif licence.

Near term strategy

The next stage of the Company's business strategy is to accelerate the growth potential of the assets in the portfolio by advancing each one through the development life cycle and materialising value as follows:

1. Trinidad - an opportunity to evaluate additional CO2 EOR projects based on the Company's extensive CO2 EOR studies to date, attractive project economics, environmental approvals granted and access to surplus CO2 supply;
2. Morocco - secure an option on a drill rig on attractive commercial terms in order to be able to use as leverage to attract finance from a variety of possible sources to drill its primary gas prospect in the Guercif Licence; and
3. Ireland, subject to the award of successor authorisations - an opportunity to exploit the Company's focus on gas is strengthened by the current in-country debate on reducing CO2 emissions and security of energy supply in the context of the current Brexit deadline.
   In Ireland, the Group's Licensing Option 16/30 expired on 30 November 2019 and Licensing Option 16/26 expired on 30 June 2018. The Group has applied for successor authorisations, which are under consideration. No work programme has been committed to for the next 12 months and therefore the award of any successor authorisations will be dependent primarily on attracting a farmin partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

Financing of the Company's business growth and early monetisation plans is based on remaining flexible with respect to the different options available to a Company of our size and general sentiment in the oil & gas sector to investment in the assets.

These include either on a standalone basis or in combination:

- upscaling in the medium-term potential profits split from increasing production from Trinidad CO2 EOR, both current and new operations and opportunities;
- equity funding;
- farm-out of project equity to industry peers for a carry through a defined work programme;
- sale of or investment directly into a subsidiary company for a non-controlling stake; and
- consolidation of specific project assets for sale into a larger listed or private peer company, for cash or quoted shares , such company potentially having greater access to appraisal and development capital necessary to further develop such assets which otherwise could not be developed by the Company.

Current status of the Company's Business Strategy

Trinidad – CO2 EOR operations

Since IPO, the Company has accelerated its desired objective of implementing CO2 EOR operations in the Inniss-Trinity oil field in onshore Trinidad.

The Company has undertaken the following work programme since IPO:

- carrying out desktop subsurface reservoir engineering studies to determine the potential volumes of CO2 and injection rates required for enhanced oil recovery and the corresponding forecast uplift in oil production rates;
- designing and costing the CO2 delivery system;
- supervising investigative well workover operations to ascertain the suitability of existing wells for conversion to CO2 EOR operations; and
- providing technical assistance leading to the issue of a certificate of environmental clearance from the Environmental Management Authority in Trinidad, allowing the Company to show that CO2 EOR is technically feasible and environmentally compliant.

This has allowed the progress of the approvals required to commence CO2 EOR operations during early 2020.

Moreover, the Company has also demonstrated to Heritage, based on its work to date, that potential well production rates from CO2 EOR wells, using desktop engineering models and forecasts, are significantly higher than those for conventional infill drilling and that project economics for CO2 EOR are therefore improved compared to those for infill drilling.

A consequence is that this has allowed Heritage to approve the extension of the current term of the IPSC between FRAM and Heritage to 31 December 2021 subject to CO2 injection commencing on or before 28 January 2020. The CO2 EOR Pilot Project in Inniss-Trinity has replaced 7 outstanding well commitments under the terms of the IPSC.

FRAM Option

The Company has extended its exclusive option to acquire FRAM for US$ 4.2 million up to 30 September 2020 whilst the economic benefits based on actual production rates from the CO2 EOR Pilot Project commencement of operations are quantified and analysed.

Should the Company exercise its option, it would likely be subject to a further prospectus based on a combination of any or all of debt, equity and reserves-based lending.

Morocco

The executive team brings to bear relationships, experience and expertise in identifying, securing and evaluating suitable projects. The Company's management has specific and specialised experience in the oil and gas sector in both Ireland (39 years) and Morocco (14 years).

This has facilitated an assessment on whether prospects are sufficiently attractive and consistent with the Company's strategy of managing risk through low entry cost and possible dilution by farm-out to industry peers for cash or a carry through the next stage of investment required to further de-risk and develop the prospects.

The rationale for entering Morocco

- The management has many years of familiarity in operating similar licences and, in particular, expertise in identifying potential gas sands on seismic sections;
- Onshore northern Morocco was identified as an area with attractive geology, established gas production and gas infrastructure links to the European gas market;
- Moroccan government fiscal policy towards the oil and gas sector is based on low taxation to encourage investment in exploring for, appraising and developing oil and gas prospects;
- The fiscal terms favour gas and the regulatory regime is transparent and defined in the Moroccan hydrocarbon code;
- The Moroccan government policy is to seek new indigenous sources of gas to replace mainly coal-fired power stations to help reduce the Country's CO2 emissions. Closer ties with the European Union are now being developed and the European Bank of Reconstruction and Development has provided loan facilities for the further development of the gas distribution network; and
- Pricing of produced gas is historically attractive, which when combined with the low taxation regime creates positive project economics that support the investment proposition.

Guercif Permit Agreement with ONHYM

Based on management's long-established experience in oil and gas exploration in Morocco, an area was identified with the potential for shallow gas discoveries based on trendology and geological analogy with the producing Rharb Basin. The optimum location for initial gas exploration lies just 4 kilometres from the Maghreb gas pipeline. The potential gas reservoirs occur at depths shallower than 2,000 meters. Consequently, drilling costs are lower and development costs are more manageable given the close proximity to the Maghreb pipeline infrastructure, subject to the availability of spare capacity, gas compatibility, entry pressures and negotiating pipeline transport tariffs. ONHYM, the State Oil Company, is a joint venture partner and contributes its share of development costs upon a declaration of commerciality. This provides the Company with a level of comfort that there can be partnership alignment in terms of assistance with gas development options.

Accordingly, the Company signed the Guercif Permit Agreement with ONHYM on 19 March 2019 and put in place the contractually agreed bank guarantee for the minimum exploration work programme to be executed during the initial exploration period of 30 months, commencing on 19 March 2019, of the Guercif Permit Agreement. A Joint Ministerial Order has been approved by the Ministers of Energy and Finance. This has subsequently been gazetted and therefore the Guercif Permit Agreement is in full force and effect.

The work programme for the initial exploration period negotiated by the Company is specific to addressing the Company's business growth strategy focussed on gas, lower levels of initial exploration investment and proximal location with respect to gas infrastructure and potential gas markets for power generation.

Ireland

The Company has kept its portfolio of licensing options offshore Ireland in good standing since its IPO by applying its stated strategy of minimal investment. This has been achieved by seeking renewal of licensing option rentals on their expiration and carrying out low cost in-house desktop studies.

- **Ram Head Licensing Option 16/30 -** carried out an independent reservoir engineering and conceptual field development study and a study to investigate the feasibility of re-entering and testing the 49/19-1 Marathon Oil gas discovery well drilled in 1984/5. Ram Head Licensing Option 16/30 expired on 30 November 2019; an application for a successor authorisation has been submitted.

- **Corrib South Licensing Option 16/26 -** Corrib South Licensing Option 16/26 expired on 30 June 2018. An application for a successor authorisation remains active and in good standing with the Irish government and is subject to demonstrating a financing capability additional to its published balance sheet for the year ended 31 December 2018.

The Company continues to publicise through a farm-out process the potential value of the assets in terms of Ireland's Security of Gas Supply in a post-Brexit landscape and their potential contribution, if fully appraised and developed, to reducing Ireland's CO2 emissions.

The Company, based on its management long history of involvement offshore Ireland, has produced an indicative strategic gas development proposal. It highlights the potential synergies of its assets in terms of consolidation with existing infrastructure for the purposes of developing the potential for offshore regasification of LNG and gas storage, in line with European Union strategy and adopted policy for liquefied natural gas and gas storage.. The strategic gas development proposal is being included as part of a farm-out process to potentially attract LNG suppliers and other industry parties to take an equity interest directly in the project, and for the avoidance of doubt not the Company. Other parties specialising in gas and LNG in the oil and gas sector are required by the Company in order to access the considerable financial resources necessary to progress the applications for successor authorisations for Licensing Options 16/26 and 16/30 and to further develop the Company's indicative strategic gas proposal. Several confidentiality agreements have been executed between the Company and interested parties. Further discussions are anticipated to take place during 2020, however a successful outcome to any such discussions should not be relied upon given the early stage of development of the business concept and the challenging regulatory and investment environment currently prevailing offshore Ireland in relation to the fossil fuel industry in general. The Company is engaging in discussions as operator of expired Licensing Options 16/26 and 16/30 on behalf also of its joint venture partner in the Licensing Options, Theseus Limited, under their Joint Operating Agreement and as part of the process to secure the financial capability required by the Irish regulatory authorities before the award of any successor authorisation can be approved. Any potential partners would be an addition to the current joint venture partnership of POGV and Theseus, and their participation in any successor authorisations would be subject to regulatory consents and approvals and also being novated to the existing Joint Operating Agreement for Licensing Options 16/26 and 16/30 between the Company and Theseus Limited.

The Company is actively pursuing its business development strategy to access the appraisal and development capital necessary to further develop its Irish assets where the appraisal and development costs of the larger scale projects is orders of magnitude greater than the Company's market capitalisation.

The Group's Licensing Option 16/30 expired on 30 November 2019 and Licensing Option 16/26 expired on 30 June 2018. The Group has applied for successor authorisations, which are under consideration. No work programme has been committed to for the next 12 months, nor for any time in the future, and therefore the award of any successor authorisations will be dependent primarily on attracting a partner or partners to address the financial and technical operating capability required by the regulatory authorities and to finalise a work programme which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

Dividend policy

The Company's current intention is to distribute free cash from its operational activities in Trinidad to Shareholders subject to the ongoing capex and working capital constraints necessary in relation to prudent financial management of its business operations and business development. The Company will only pay dividends to the extent that to do so is in accordance with the Jersey Companies Law and all other applicable laws. The Directors do not anticipate declaring any dividends in the short to medium term.

Near-term forward plans and requirement for additional capital

1. Trinidad

Securing exclusivity over Trinidad's surplus CO2 supply, issuing of the certificate of environmental clearance based on the Company's CO2 EOR Pilot Project design specifications and environmental monitoring plan, and completion of initial well workover surveys, have created the regulatory and technical framework for applying CO2 EOR technology to the AT-4 Block of the Inniss-Trinity field. Scope exists to start planning for additional CO2 EOR Pilot Projects, both within other parts of the Inniss-Trinity field and in adjacent fields where the positive criteria for CO2 EOR identified in the AT-4 Block can potentially be extrapolated and tested, initially by using desk-top reservoir engineering models, downhole well completion capability and well integrity for CO2 EOR injection, and by geological compatibility with the AT-4 Block.

The Net Placing Proceeds will be used to complete and supervise CO2 EOR Pilot Project start-up to "first oil" including: third party HSE monitoring; management of well operations and downhole completions; periodic civil works and road maintenance for truck deliveries; additional well workovers; dedicated CO2 site security; generator and installation for reliable power supply; telecommunications; Massy CO2 operator costs; standby CO2 supply; real-time reservoir engineering monitoring; safety equipment; and well insurance.

A successful CO2 EOR Pilot Project will potentially de-risk the technical case for CO2 EOR and facilitate the utilisation of any unused contingency funds from of the Net Placing Proceeds for screening desk-top studies in preparation for selecting additional CO2 EOR sites necessary to upscale the Company's profits and revenue-generating capabilities derived from production in line with its business development strategy.

2. Morocco

The ongoing evaluation of the prospectivity of the area included in the Guercif Petroleum Agreement has identified a shallow gas target for early drilling.

A window of opportunity exists to utilise the in-country presence of two different drilling rigs. This may significantly reduce drilling costs by lowering mobilisation and demobilisation expenses compared to importing a rig from overseas. Also, existing well services contractors used to provide such services to the in-country operators to which the rigs are currently under contract can potentially also be used by the Company, thereby creating synergies and potentially reducing the lead-time to drilling compared to the Company securing such services independently. The Board believes that rig availability currently exists up until the second quarter of 2020.

On 6 December 2019 PGV entered into a rig option agreement (the "**Rig Option**") with Star Valley Drilling Ltd. ("**Star**"), a Canadian drilling company currently undertaking an extensive drilling programme for SDX Energy Plc in the Rharb Basin west of the Guercif using its rig no. 101.

The Rig Option is to 31 January 2020, unless otherwise mutually agreed by PGV and Star, to allow for negotiation and execution of a legally binding rig contract, including all commercial terms.

The Rig Option provides for a rig mobilisation date within a window commencing 15 March 2020 and ending 30 April 2020 unless otherwise agreed by mutual consent of PGV and Star.

A commercial driver for the Company to prudently accelerate exploration drilling is linked to the available capacity in the Maghreb gas pipeline. In 2021 Morocco will acquire 100% of the capacity rights for the Maghreb gas pipeline. Existing gas throughput contracts could be supplemented by new contracts with the European Union to effectively reduce current available capacity. The potential development of the

Tendrara gas field could also further reduce available capacity. A successful first exploration well in Guercif, proximal to the Maghreb gas pipeline, could accelerate a declaration of commerciality and the submission of a plan of development. A commercial opportunity exists to utilise potential spare capacity in the Maghreb pipeline before other new agreements are negotiated and executed by other potential competitors.

The Company is therefore seeking through this Document to utilise the majority of the Net Placing Proceeds to: carry out well planning, design and environmental impact studies; procure long-lead well items and drilling materials; negotiate and execute a rig contract and mobilise a rig; carry out civil works to prepare the drilling site; and drill one exploration well to 2,000 metres.

This allows the Company to accelerate its strategy for potential growth generated by value creation through low cost exploration drilling. The commercial opportunity is near-term. The strategy to focus on a responsible approach to fossil fuel exploitation is also being put into practice, as drilling success leading to development potentially helps to reduce Morocco's CO2 emissions by providing indigenous gas to replace oil and coal for power generation.

3. Ireland

The Group's Licensing Option 16/30 expired on 30 November 2019 and Licensing Option 16/26 expired on 30 June 2018. The Group has applied for successor authorisations, which are under consideration. No work programme has been committed to for the next 12 months nor thereafter, and therefore the award of any successor authorisations will be dependent primarily on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

Some management time, within the context of the existing management team's consultancy agreements, will be devoted to continuing with farm-out efforts to attract a substantive partner capable of satisfying the financial and technical operating requirements required by the regulatory authorities for the award of successor authorisations, carrying the Company in potentially significant work programme commitments to be negotiated with the regulatory authorities, and supportive of the Company's business development strategy for gas in Ireland. Farm-out efforts will only comprise management presentations and meetings with any interested parties and will not involve any funds from the Net Placing Proceeds other than those included in corporate running costs attributable to existing management consultancy contracts. None of the Net Placing Proceeds will be used for any potential work programmes for Ireland. The Company believes that the current uncertainty in relation to the Irish Government's changing policy towards fossil fuel exploration necessitates that investment decisions be deferred until the policy is formally clarified.

4. Corporate

The Company does not intend to use any part of the Net Placing Proceeds to eliminate the outstanding balance of the CLN as the Lender has agreed to waive this requirement of the CLN in return for the issue of 2,500,000 Ordinary Shares at the Placing Price by the Company to the Lender. These Ordinary Shares will be issued following Admission, conditional on the Company obtaining new Shareholder approval for such issue, and do not form part of the New Ordinary Shares. In the event that Net Placing Proceeds raised exceed the Company's working capital requirements then excess Net Placing Proceeds would potentially be available to contribute towards repayment of the CLN in cash. Reduction of the CLN in cash repayments gradually reduces the uncertainty of the ability to convert the CLN into an unknown number of the Company's shares in the future dependent upon quoted share price at the time of conversion, thereby giving greater certainty for the Company's shareholders of the dilutionary impact of the terms of the CLN.

Accelerating the drilling during the initial exploration period of 30 months of the Guercif Petroleum Agreement is in the Company's interest as under these circumstances it would release the first USD 1 million of the gross bank guarantee amount of USD1.5 million in favour of ONHYM, earlier in the initial exploration period to provide additional future working capital for the Company. The terms of the Guercif Petroleum Agreement determine that USD 1 million of the bank guarantee is returned to the Company on completion of the well and the delivery of all the data associated with the well to ONHYM.

PART VIII
DESCRIPTION OF ASSETS

Trinidad - Near Term Production

Well Participation Agreement – Pilot CO2 Enhanced Oil Recovery Project Inniss-Trinity Field

The producing Inniss-Trinity oil field is located onshore Trinidad in the Southern Basin approximately 10 km southeast of the Barrackpore-Penal oil field and approximately 75 km south of the capital Port of Spain. The Inniss-Trinity Licence covers an area of 23.35 km² and currently contains 86 producing wells that are available for the application of enhanced oil recovery techniques.

Through its wholly-owned subsidiary, POGT, the Company currently holds an interest in a WPA signed with FRAM, a wholly-owned subsidiary of Steeldrum, on 17 November 2017 and relating to the Company's entitlement to profits derived from its investment in the producing Inniss-Trinity oil field ("Inniss-Trinity").

Inniss-Trinity is licenced to Petrotrin, the State Oil Company. Following the closure of Petrotrin's oil refinery in Trinidad, Petrotrin was re-structured during the end of 2018 to create the new State Oil Company Heritage Petroleum Company Ltd. ("Heritage").

FRAM is operator of the Inniss-Trinity field under the terms of an Incremental Production Services Contract with Heritage ("IPSC"). The IPSC allows for FRAM to invest in Inniss-Trinity by satisfying certain annual infill drilling commitments during the life of the IPSC. In return, FRAM receives 100% of the benefits of all incremental production achieved through the investment relative to the base line production established for the field prior to the investment being made. FRAM's net incremental production revenues are after deduction of operating costs and certain royalties and taxes. Historical tax losses accumulated within FRAM are available for offset against Petroleum Profits Tax on operating profits. CO2 EOR Project Costs can also be offset against 18% Supplemental Petroleum Tax where applied when the price of West Texas crude is between US$50.01/brl and US$90.00/brl.

The term of the IPSC has been extended until 31 December 2021, conditional upon CO2 injection commencing on or before 28 January 2020. The outstanding FRAM drilling commitment of 7 wells has been replaced by the CO2 EOR Pilot Project.

FRAM currently produces between 120 and 150 bopd from the field, which is sold directly to the state-owned oil company Heritage. FRAM is engaged in operating and drilling infill development/production wells in the field and carrying out workovers for selected wells based on up to 86 wells that have been assigned by Heritage to FRAM under the IPSC.

Under the WPA, POGTL is entitled to a profit split from all profits generated from incremental production attributable to enhanced oil production from the CO2 EOR Pilot Project under the same terms of the IPSC through the Company's investment in Inniss-Trinity. However, in the specific case of the WPA, POGT has capped the operating costs at US$10/bbl. and will also benefit from utilising FRAM's historical tax losses. POGT is not a partner in the IPSC and therefore has no exposure to any of the FRAM commitments relating to the IPSC. POGT will receive 100% of all operating profits until payback of its investment and thereafter operating profits will be split 50:50 between POGT and FRAM. Under the WPA, POGT also has an option up to 30 September 2020 to acquire certain assets of Steeldrum, including FRAM for an agreed sum of US$4.2 million.

The completion of the sale of Steeldrum, owners of FRAM, to Columbus was announced on 8 October 2018. The WPA remains in full force and effect following the sale of FRAM. FRAM is now therefore a wholly-owned subsidiary of Columbus and retains its 100% of the rights of the IPSC for Heritage's Inniss-Trinity licence onshore Trinidad.

During 2018 the WPA with FRAM was amended to re-focus on Enhanced Oil Recovery operations using locally sourced carbon dioxide for injection ("CO2 EOR"). This technique is widely used in oil fields in the United States, where an affordable source of C02 is available. The option to acquire FRAM has been extended to 30 September 2020. An option to acquire Cory Moruga Holdings Ltd., another wholly-owned subsidiary of Steeldrum, was dropped in order to focus resources on the Inniss-Trinity asset.

CO2 Supply

To further the initiation of a CO2 EOR Pilot Project in Inniss-Trinity, a Heads of Agreement for C02 Gas Sales ("**CO2 HOA**") was entered into with the only in-country C02 supplier, Massy Gas Products Trinidad Ltd. ("**Massy**"), based on a minimum scoping daily delivery of 60 Mt C02.

An exclusivity period to negotiate the C02 Gas Sales Agreement, initially to 31 August 2018, was extended to 30 November 2018 and has been subsequently extended further to 30 September 2020.

CO2 EOR planning and and operations

During the year an independent CO2 EOR reservoir engineering study was completed for the AT-4 Block within the Inniss-Trinity Field. Based on this, pilot C02 injection volumes have been modelled and incorporated in the CO2 Gas Sales Agreement discussions with Massy.

Oil production forecasts derived from the above study have been modelled and input into the design criteria for the CO2 EOR-dedicated surface production facilities. Pilot C02 EOR is forecast from desk top studies to increase production compared to the current production from the existing wells in the AT-4 Block chosen for the CO2 EOR Pilot Project by lowering oil viscosity and increasing current reservoir pressures.

A competent person's report by SLR Consulting commissioned by the Company in 2019 had indicated Gross Contingent Recoverable Oil Resources pending development for a full-field CO2 EOR development of the Inniss-Trinity field of: 5.3 million barrels (Low Estimate); 6.8 million barrels (Best Estimate) and 8.9 million barrels (High Estimate). These resources estimates are attributable to FRAM's interest in the IPSC. Exercising the Company's option to acquire FRAM, as FRAM is the party at present to the IPSC and not the Company, and following all regulatory consents and approvals for the change of control of FRAM after an acquisition, would allow the aforementioned resources to be included by the Company in its list of assets. For the avoidance of doubt, currently the Company only receives a split of net operating profits only under the terms of the WPA from any potential production from the CO2 EOR Pilot Project in the AT-4 Block within the Inniss-Trinity field, which is the only part of the Inniss-Trinity field to which the WPA currently applies.

A three-well workover programme for AT-4, AT-5X and AT-13 has been executed to survey the wells for suitability and integrity for CO2 EOR operations based on the Company's CO2 EOR design specifications. Following the results of the well workover survey, the Herrera #2 Sand will be isolated in the wellbore in AT-5X for initial CO2 injection followed by oil production whilst simultaneously injecting CO2 continuously into AT-13. Currently producing wells AT-6, AT-12 and IN-6 in the AT-4 block may also potentially exhibit enhanced oil production if the pilot CO2 injection is completely successful.

The layout of the injection and production wells and the operational plan for CO2 EOR injection and oil production has been finalised.

HSE

An environmental monitoring programme has been established with the Environmental Monitoring Authority ("**EMA**") and collection of "base line" samples has begun.

The Health and Safety Plan for CO2 EOR operations has been drafted and will be updated after further consultations with the EMA and Massy.

A Certificate of Environmental Clearance has been issued by the EMA for CO2 EOR operations in Inniss-Trinity.

The Company is dependent on FRAM and Heritage receiving regulatory approval from the Ministry of Energy and Energy Industries ("**MEEI**") for the CO2 EOR Pilot Project to be implemented in Inniss-Trinity. Heritage approval for the pilot CO2 EOR injection was given in 2019 subject to final approval by the MEEI, which was received by FRAM on 3 January 2020.

The Net Placing Proceeds will be used to complete and supervise CO2 EOR Pilot Project start-up to "first oil" including: third party HSE monitoring; management of well operations and downhole completions; civil works and road maintenance for truck deliveries; additional well workovers and down-hole equipment; dedicated CO2 site security; generator and installation for reliable power supply; telecommunications; Massy CO2 operator costs; standby CO2 supply; real-time reservoir engineering monitoring; safety equipment requirements; and well insurance.

Injection of CO2 over a period of up to 60 days, as currently forecast, is a requirement to re-pressurise the Herrera #2 Sand reservoir. This will be followed by continuous injection of CO2 into the Herrera #2 Sand in the AT-13 well and monitoring oil production from the AT-5X well, and potentially IN-6, AT-6 and AT-12 too. Real-time pressure data will be continuously collected to assess and adjust if necessary the CO2 injection pressures and volumes.

The gross cost of the work programme for the next 12 months is estimated to be £318,665, inclusive of a 5% contingency.

Morocco Near Term Exploration

Guercif Petroleum Agreement – Moulouya Prospect

Through its wholly-owned subsidiary PGV, the Company holds a 75% working interest in and is the operator of the Guercif Petroleum Agreement. ONHYM, the State oil company, holds 25% and is carried through exploration, but funds its pro-rata share of all costs upon a Declaration of Commerciality. ONHYM is owned by the Moroccan government and is involved in oil exploration, appraisal and development within Morocco. In addition to mining activities, ONHYM is the regulatory authority for all oil and gas licences in Morocco.

The Guercif Petroleum Agreement, comprising the Guercif Permits I, II, III and IV, is located in the Guercif Basin and covers 7,269 km², c. 250 km due east of and on trend with the Rharb Basin, where shallow commercial gas production has been established by SDX Energy Plc for several years. Guercif also lies approximately 180 km due north-west of Tendrara, where deep discovered gas is currently being appraised and potentially developed by Sound Energy Plc.

The Licence is for 8 years and is split into an Initial Period of 30 months, commencing on 19th March 2019; a First Extension Period of 36 months duration; and a Second Extension Period also of 30 months. After each Licence Period there is an opportunity to withdraw from the Licence, without entering the next Licence Period.

In the Initial Period the work programme comprises 250 kilometres of 2D seismic reprocessing and AVO analysis and the drilling of one well to a minimum depth of 2,000 metres. Desk-top geological and gas marketing studies will also be carried out. The Minimum Exploration Commitment is US$3,458,000 as detailed in paragraph 14.13 of Part XIV (*Additional Information*) of this Prospectus.

The fiscal terms in Morocco are restricted to a 5% State royalty for gas, applicable after the first 10.6 BCF of net production to the operator, and corporation tax charged at 31%. However, there is a 10-year "holiday" before corporation tax will be charged and any unused tax losses can be offset against the tax due. There are no signature bonuses but production bonuses in the form of cash payments exist with a maximum one-off payment of US$5,000,000 on production greater than 30,000 BOE/day. A discovery bonus of US$1,000,000 is also payable.

Gas prices for producers in Morocco are currently higher than UK National Balancing Point ("**NPB**") prices for domestic delivery.

History

Guercif has been very lightly explored with only 4 deep exploration wells drilled by Elf in 1972 (GRF-1), Phillips in 1979 (TAF-1X), ONAREP (the forerunner of ONHYM) in 1985 and 1986 (MSD-1 and KDH-1) and 2 shallow stratigraphic wells drilled by BRPM for coal exploration in the 1950s.

TransAtlantic re-entered, logged and tested the MSD-1 well, originally drilled in 1985, in 2008 but the logging and testing failed to establish the presence of hydrocarbons in the Jurassic.

The seismic inventory includes 3,291 kilometres of 2D seismic data acquired between 1968 and 2003, including a new 300-kilometre ONAREP 2D seismic survey acquired in 2003, which were reprocessed in 2006 by TransAtlantic when Pre-Stack Time Migration was applied for the first time to the seismic inventory. TransAtlantic also acquired an aero magnetic and aero gravity survey in 2006, comprising 10,000 line kilometres.

Historical exploration focus was entirely on the Jurassic and was completed before the shift in focus took place that resulted in shallow (Tertiary) gas production in the Rharb Basin and successful deep (Triassic) gas appraisal drilling at Tendrara.

In this context therefore Guercif has never been the focus of exploration for the more recent tertiary targets encountered in the gas-producing Rharb Basin and this is the new focus for PGV.

Current Prospectivity

The Company has re-evaluated the existing reprocessed 2D seismic database and well data and has identified the Moulouya_1 Prospect as being drill-ready. The core prospective area of the Moulouya_1 Prospect covers up to 34 sq. km. and is supported by multiple seismic amplitude anomalies. The current drilling programme will test several stacked seismic amplitude anomalies to evaluate their potential to reflect the presence of reservoirs and the potential for gas generation and migration.

An off-set well, GRF-1 drilled in 1972 before the acquisition of the 2003 ONAREP seismic, less than 1.5 kilometres to the south-east of the edge of the seismic amplitude anomaly, had minor dry gas shows in the Tertiary. The previous operator, TransAtlantic Petroleum, re-evaluated in 2006 the wire line logs from GRF-1 and interpreted gas pays between 1,860 and 1,960 meters below ground level in the basal Tertiary section. No corresponding gas shows were seen on mud logs when the well was originally drilled and the well has never been tested to determine whether this interval is indeed gas-bearing.

Two micro-seepage surveys carried out for TransAtlantic by Geo-Microbial Technologies in 2006 and 2007 also identified dry gas around the GRF-1 well in soil samples.

Small volumes of gas could potentially be utilised for the domestic gas market if additional transport infrastructure was added, but larger volumes require gas-to-power and export options.

A competent person's report by SLR Consulting commissioned by the Company in 2019 has indicated Net Prospective recoverable Gas Resources in the Tertiary (Moulouya_1 Prospect primary objectives) in the range of 320 to 659 BCF with a 34% geological chance of success. For the avoidance of doubt this is not an economic chance of success.

Forward Programme

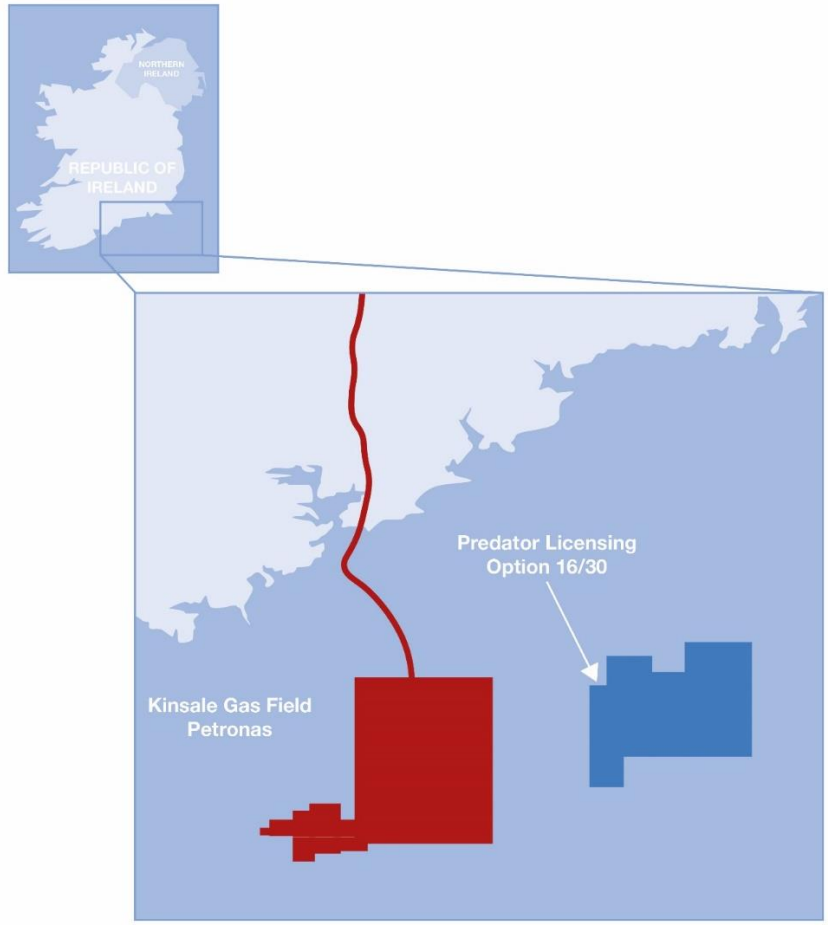
The Company believes that the Moulouya_1 Prospect warrants a fast-tracked approach to drilling in order to capitalise upon its attractive valuation metrics and the ability to accelerate a gas development in the case of a gas discovery to exploit the current demand for gas in Morocco.

The Company is seeking through this Document to utilise the majority of the Net Placing Proceeds for well planning, well design, and HSE; drill site preparation and civil works; procurement of well casing, mud and wireline logging services; rig mobilisation and demobilisation; construction of base camp; drilling one exploration well to 2,000 metres; and well supervision. The well is currently forecast to take 20 days to drill to 2,000 metres.

The gross cost of the work programme for the next 12 months is estimated to be £2,022,102.

Ireland - Medium Term Appraisal and Exploration

Appraisal: North Celtic Sea Offshore Ireland



LO 16/30 – Ram Head Gas Project

Through its wholly-owned subsidiary POGV, the Company currently holds a 50% working interest in and is operator of L0 16/30, which contains the 49/19-1 and Ardmore 49/14-1 gas discoveries made by Marathon Oil Ireland Ltd in 1984 and 1975 but never subsequently appraised.

LO 16/30 is located in the North Celtic Sea Basin and covers 799 km², c. 75 km offshore from the current landfall of gas from the Kinsale field at Inch, County Cork. It is situated in approximately 100 m of water depth. The Licensing Option is located approximately 40 km east of the Petronas-operated Kinsale Head Gas Field, for which an application to decommission has been submitted to the regulatory authorities for approval.

History

In the past, under the operatorship of Marathon, three wells were drilled within the Licensing Option area. Of these 2 wells successfully logged hydrocarbon-bearing reservoirs and one of which, 49/14-1, was tested for gas and flowed 8 mm cfgpd from several different horizons in the Lower Cretaceous.

The Company's joint venture partner is Theseus Limited ("**Theseus**"), which is a private company holding 50% of Licensing Options 16/26 and 16/30 offshore Ireland. It has no other licence interests or business activities. It is a party to the Joint Operating Agreements for Licensing Options 16/26 and 16/30 operated by POGV.

During 2018, following the award of a two-year Licensing Option to the Company and its partner Theseus, the Company carried out a number of studies to re-determine the quality of the gas reservoirs in the original discovery well 49/19-1; to complete an initial reservoir engineering study and scoping development plan; and to assess the technical feasibility of re-entering the 49/19-1 well to test the previously logged gas-bearing Jurassic reservoirs to validate production forecasts determined from the desk top studies.

A competent person's report by SLR Consulting, commissioned by the Company in 2019 has indicated net prospective recoverable gas resources in the Jurassic in the range of 118 to 1,370 BCF with a 12% chance of success. The Company's Conceptual Development Plan below is addressed in the Competent Person's Report by SLR Consulting.

The programme of 2018/9 studies was designed to assess reservoir risk in terms of gas deliverability and also to determine a cost-effective way to flow-test the discovered gas, without drilling an expensive appraisal well.

Reservoir studies based on new NuTech log analysis technology have identified 64 feet of previously unrecognised good quality gas pay in 49/19-1. A reservoir engineering study and Conceptual Development Plan was commissioned by the Company through a third party consultant Dr. John Tingas. This has indicated a potential field development profile of 400 mm cfgpd from a minimum of 10 vertical wells. An ultimate gas recovery of 96% over 59.3 years was estimated, with no economic cut-offs applied. The scoping development concept requires gas to be landed at the existing Inch brown field site and therefore the Company has made a submission to the regulatory authorities during 2018 stressing the importance of the continuance of the Inch site, after decommissioning of the Kinsale Gas Field facilities, for future potential gas developments.

Forward Programme

An application for a successor authorisation to Licensing Option 16/30 was submitted on 31 October 2019, following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018, to convert it to a SEL upon expiry of Licensing Option 16/30 on 30 November 2019.

For the award of a standard exploration licence successor authorisation a substantial work programme commitment is required, which is likely to include 3D seismic acquisition and drilling. At this early stage in the application process for a successor authorisation no negotiations have been entered into with the regulatory authorities regarding a specific work programme.

No work programme has been committed to for the next 12 months, nor beyond this period, and therefore the award of any successor authorisation will be dependent primarily on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to a successor authorisation.

Some management time, within the context of the existing management team's consultancy agreements, will be devoted to continuing with| farm-out efforts to attract a substantive partner capable of satisfying the financial and technical operating requirements required by the regulatory authorities for the award of a successor authorisation, carrying the Company in potentially significant work programme commitments to be negotiated with the regulatory authorities, and supportive of the Company's business development strategy for gas in Ireland. Farm-out efforts will only comprise management presentations and meetings with any interested parties and will not involve any funds from the Net Placing Proceeds other than those included in corporate running costs attributable to existing management consultancy contracts. None of the Net Placing Proceeds will be used for any potential work programmes for Ireland. The Company believes that the current uncertainty in relation to the Irish Government's changing policy towards fossil fuel exploration necessitates that investment decisions be deferred until the policy is formally clarified.

The precise details of the changing Government policy with respect to fossil fuel exploration remain to be announced. As a consequence, the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and finance necessary to commit to a work programme for any successor authorisation. Under these circumstances, the Company may lose ability to progress a successor authorisation.

Exploration: Atlantic Margin Offshore Ireland

Licensing Option 16/26 – Corrib South Gas Exploration

Through its wholly-owned subsidiary POGV, the Company currently holds a 50% working interest in and is operator of Licensing Option 16/26, which contains the 18/25-2 well drilled by Enterprise Oil in 1999.

Licensing Option 16/26 is located in the Slyne Basin and covers 302 km², c. 70 km offshore from the current landfall of gas from the Corrib field in County Mayo. It is situated in approximately 335 m of water depth. The Licensing Option is adjoining and to the south of the Vermillion-operated Corrib Gas Field, which is currently Ireland's largest producing gas field.

History

In the past, under the operatorship of Enterprise Oil, 640 km² of 3D seismic were acquired in 1997 which resulted in the identification of the Corrib Gas Field structure and two structures to the south within the Licensing Option area. One well, 18/25-2, was drilled in 1999 within the Licensing Option area on the structure closest to the Corrib Gas Field, after the first Corrib discovery well was drilled. No logged hydrocarbon-bearing reservoirs were penetrated but the Corrib Field gas reservoir was proven to be present in the well. The second structure, the "Deel Prospect" and re-named "Corrib South" by the Company, was never drilled and was eventually relinquished by Enterprise's successor, Shell, prior to the approval of the Corrib Gas Field Plan of Development by the regulatory authorities.

During 2017 and 2018, following the award of a two-year Licensing Option to the Company and its partner Theseus Ltd. in the 2015 Atlantic Margin Licensing Round, the Company carried out a re-assessment of the Corrib South Prospect based on integrating regional geological and geophysical data and new information from the producing Corrib gas field. The Company concluded that the Corrib South Prospect was potentially larger than previously considered and extended beyond the limit of the current 1997 3D seismic coverage.

Based on this re-interpretation of the Corrib South Prospect, SLR Consulting were commissioned by the Company in 2018 to produce a Competent Person's Report. This indicated net prospective recoverable gas resources in the Triassic reservoir (the Corrib Gas Field reservoir) to be in the range of 92.3 to 452.4 BCF with a 30% chance of success.

Forward Programme

The Company noted the announcement in the last quarter of 2018 by the new incoming operator of the Corrib Gas Field, Vermilion, confirming the completion of the sale of Shell's 45% interest in Corrib for approximately $1.3billion to Nephin Energy Holdings Limited and the transfer of operatorship to Vermilion. The Company further noted comments attributed to Vermilion regarding outline plans to expand the Corrib project and in addition that it would look to do deals with other oil and gas companies exploring in the waters around Corrib, either by allowing those companies to use Corrib Infrastructure to transport gas, or by buying stakes in those companies.

The announcement lends substance to the Company's business model in relation to focussing solely on gas in Ireland and only in those areas where gas production already has an established offshore and onshore infrastructure.

It is a potential catalyst for farm-out and M&A transactions with infrastructure owners' offshore Ireland seeking additional assets to expand their existing projects.

An application to convert Licensing Option 16/26 into a FEL was made on 25 May 2018 before the expiry of the Licensing Option on 30 June 2018 and is still actively under consideration by the regulatory authorities.

The work programme for a successor authorisation, a FEL, initially proposed by the Company in consultation with the regulatory authorities in Ireland was for 200km² of 3D seismic acquisition and processing in the first 3-year phase of the FEL, with an option to drop the Licence after 3 years unless committing to an exploration well in the next succeeding 3-year phase of the Licence. Gross (100%)

costs of this work programme were estimated to be Euros 3,204,773 in the event a successor authorisation was awarded to and, at its sole discretion, accepted by the Company.

For the avoidance of doubt, no work programme has been committed to for the next 12 months, nor beyond this period, and therefore the award of any successor authorisation will be dependent primarily on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to a successor authorisation if it cannot commit to a future work programme.

Some management time, within the context of the existing management team's consultancy agreements, will be devoted to continuing with farm-out efforts to attract a substantive partner capable of: satisfying the financial and technical operating requirements required by the regulatory authorities for the award of successor authorisations; of carrying the Company's share of any future potentially significant work programme commitments, and of being supportive of the Company's business development strategy for gas in Ireland. Farm-out efforts will only comprise management presentations and meetings with any interested parties and will not involve any funds from the Net Placing Proceeds.

The precise details of the changing Government policy with respect to fossil fuel exploration remain to be announced. As a consequence the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and finance necessary to commit to a work programme for any successor authorisation. Under these circumstances the Company may lose ability to progress a successor authorisation.

Regulatory Environment

Ireland remains an extremely challenging regulatory environment and concerns over Brexit may provide further uncertainty in the ability of operators to efficiently access oil field services, vessels and rigs in a cost-effective manner out of the UK.

The Company therefore maintains a flexible strategy towards its assets offshore Ireland in the context of minimising financial exposure through seeking farm-in partners and attempting to generate M&A activity through synergies created by the consolidation of different assets.

The Company, based on its management long history of involvement offshore Ireland, has produced an indicative strategic gas development proposal. It highlights the potential synergies of its assets in terms of consolidation with existing infrastructure for the purposes of developing the potential for offshore regasification of LNG and gas storage, in line with European Union strategy and adopted policy for liquefied natural gas and gas storage.. The strategic gas development proposal is being included as part of a farm-out process to potentially attract LNG suppliers and other industry parties to take an equity interest directly in the project, and for the avoidance of doubt not the Company. Other parties specialising in gas and LNG in the oil and gas sector are required by the Company in order to access the considerable financial resources necessary to progress the applications for successor authorisations for Licensing Options 16/26 and 16/30 and to further develop the Company's indicative strategic gas proposal Several confidentiality agreements have been executed between the Company and interested parties. Further discussions are anticipated to take place during 2020, however a successful outcome to any such discussions should not be relied upon given the early stage of development of the business concept and the challenging regulatory and investment environment currently prevailing offshore Ireland in relation to the fossil fuel industry in general. The Company is engaging in discussions as operator of expired Licensing Options 16/26 and 16/30 on behalf also of its joint venture partner in the Licensing Options, Theseus Limited, under their Joint Operating Agreement and as part of the process to secure the financial capability required by the Irish regulatory authorities before the award of any successor

authorisation can be approved. Any potential partners would be an addition to the current joint venture partnership of POGV and Theseus, and their participation in any successor authorisations would be subject to regulatory consents and approvals and also being novated to the existing Joint Operating Agreement for Licensing Options 16/26 and 16/30 between the Company and Theseus Limited.

Whilst maintaining an automatic right to progress to a successor authorisation, subject to proving financial and technical capability, the Company retains some short-term leverage in farm-out and M&A discussions with interested parties. Ireland's recently stated political positioning towards fossil fuel exploration, appraisal and development, reflecting climate change concerns, lays emphasis on promoting gas exploration and development as a transition fuel to a greener energy mix; respects the continuance of existing licences and their potential successor authorisations; but makes it more difficult for new licences to be awarded under the proposed new regulatory framework. Potential farminees interested in the exploration and development of gas in Ireland may be attracted to existing licences rather than get involved in an extended regulatory process to acquire new licences in any future licensing round yet to be announced. However, until the changing government policy towards fossil fuel exploration is clarified, investment decisions may be deferred and the ability to finance the further development of the Company's Irish assets within a reasonable time framework acceptable to the regulatory authorities may prove impossible.

PART IX
THE COMPANY, BOARD AND CORPORATE GOVERNANCE

The Company

The Company was incorporated on 19 December 2017 as a company with limited liability under the Jersey Companies Law and with an indefinite life. The Company was listed on the London Stock Exchange (Standard List) on 24 May 2018.

Its share capital consists of Ordinary Shares, all of which were admitted to trading on the London Stock Exchange Main Market (Standard Segment). It is intended that the New Ordinary Shares will also be admitted by the FCA to a Standard Listing on the Official List in accordance with Chapter 14 of the Listing Rules and to trading on the London Stock Exchange's main market for listed securities.

The Directors

The Directors of the Company as at the date of this document are as follows. Details of their consultancy arrangements and letters of appointment are set out at paragraph 7 of Part XIV (*Additional Information*) of this Document. The Directors will seek to appoint further members to the Board in due course. There are no known conflicts between any of the Directors and the Company:

Carl Kindinger, Non-Executive Chairman (age 68, DOB 29 April 1951)

Mr Kindinger has held senior corporate finance roles for 30 years, including board level appointments, in a multitude of industries in several countries, including for much of the past fifteen years in oil and gas exploration. He joined the Board of Island Oil & Gas in 2006 and was a founder member of Pathfinder Hydrocarbon Ventures, later profitably on-sold to Fastnet Oil and Gas Ltd, a UK-based oil and gas explorer.

He is an associate member of the Institute of Chartered Management Accountants and also holds a degree in economics and an MBA.

His experience has been gained in small and medium sized companies in Africa, the Middle East, Ireland and Romania. He has participated both at executive committee and board level in strategic decision making. His major achievements include identifying, evaluating and promoting major investment projects, raising finance in difficult circumstances, a tax saving-led equity and debt restructuring, and mergers and acquisitions. He is seasoned at high level negotiations with JV partners, suppliers and principals. He has considerable experience in Stock Exchange and IFRS reporting, IPO requirements, business plans and performance evaluation.

Paul Griffiths, Chief Executive Officer (age 66, DOB 04 January 1954)

Mr Griffiths has 30 years' oil and gas industry experience, including with the Libyan National Oil Corporation and Gulf Oil, and as CEO of both Island Oil & Gas Plc and Fastnet Oil and Gas Plc. During this time Mr. Griffiths has managed 2D and 3D seismic data acquisition and processing projects onshore and offshore; drilling and testing programmes, both onshore and offshore; and geological and reservoir simulation desk top studies. Mr. Griffiths is also experienced in business development in respect of licence acquisitions, farm-ins, farm-outs, gas marketing and gas sales contracts and negotiations with government agencies. In 2006, Mr. Griffiths put together and led the team that drilled the first successful exploration well in offshore southeast Ireland in 16 years. In 2008 he put together and led the team that generated and submitted the plan of development for the Amstel Field in the Netherlands and in 2014 he put together and led the team that carried out the Tendrara gas field re-evaluation prior to a successful

appraisal drilling programme by Sound Energy. He is a geology graduate of the Royal School of Mines (London) and an Associate of the Royal School of Mines.

Ronald Pilbeam, Project Development Director (age 74, DOB 26 June 1945)

Mr Pilbeam has over 40 years' technical and commercial experience in energy-related E&P activities. During this time Mr Pilbeam has worked with Parsons Brinckerhoff in the United States, the Caribbean and Brazil, then with United Technologies in Brazil, before becoming associated with Unigas International both in Brazil and South Africa. Mr Pilbeam has undertaken the management of a number of projects in oil & gas shipping, gas-to-liquids, offshore LNG, onshore petro-chemical plant, gas storage, and gas handling, pipelines and terminals. In so doing, Mr Pilbeam has also amassed considerable international experience in working with government, industry and commerce, to achieve often challenging objectives. A British national, Mr Pilbeam is an engineering graduate of King's College (London), a licensed Professional Engineer (Canada), an Associate Member of the Institution of Civil Engineers (UK) and a member of the Jersey Association of Directors and Officers.

Dr Stephen Staley, Non-Executive Director (age 59, DOB 1 March 1960)

Dr Staley has 35 years' wide-ranging management, technical and commercial experience in the international oil, gas and power sectors. He was the CEO, and a director and co-founder, of Upland Resources Limited, a London-listed (Standard Listing) oil & gas company currently with assets onshore UK. He is also a non-executive director of 88 Energy Limited, an Australian oil & gas company with assets onshore Alaska. 88 Energy has a dual listing on the ASX and AIM. Dr Staley co-founded and brought to the AIM market both Fastnet Oil & Gas Plc (where he was the founding CEO) and Independent Resources Plc (where he was the founding managing director). He was also both a technical consultant to, and non-executive director of, Cove Energy Plc – the highly successful East Africa focused explorer that went from having a market capitalisation of £2 million in mid-2009 to being sold to PTTP for £1.2 billion in less than three years. Dr Staley is owner and founder of Derwent Resources Limited, an upstream consultancy advising on oil and gas opportunities. Prior to this he has worked for Cinergy Corp., Conoco and BP.

He holds a BSc (Hons.) in geophysics from Edinburgh University, a PhD in petroleum geology from Sheffield University and an MBA from Warwick University. He is a fellow of the Geological Society and a member of the European Association of Geoscientists & Engineers, the Petroleum Exploration Society of Great Britain and The Arctic Club**.**

The Company Secretary

The Company Secretary is OAK Group (Jersey) Limited, with registered office at 3rd Floor, Standard Bank House, 47 – 49 La Motte Street, Jersey JE2 4SZ.

Directors' Fees

The services of Mr Griffiths as chief executive officer of the Company on a part-time basis (120 hours in each calendar month) are provided to the Company by Petro-Celtex Consultancy Limited ("**Petro-Celtex**") pursuant to a consultancy agreement entered into by Petro-Celtex with the Company. Under the consultancy agreement, Petro-Celtex is entitled to a fee of £80,000 per annum plus VAT (if applicable) for the basic 120 hours per calendar month, and reimbursement of reasonable expenses.

The services of Mr Pilbeam as project development director of the Company on a part-time basis (75 hours in each calendar month) are provided to the Company pursuant to a consultancy agreement entered into by Mr. Pilbeam with the Company. Under the consultancy agreement, Mr. Pilbeam is entitled

to a fee of £50,000 per annum plus VAT (if applicable) for the basic 75 hours per calendar month, and reimbursement of reasonable expenses.

Further details of these agreements are set out in paragraph 7 of Part XIV *(Additional Information)* of this Document.

Carl Kindinger is entitled to an annual fee of £25,000 as a Non-Executive Director, plus reasonable expenses.

Dr Staley is entitled to an annual fee of £30,000 as a Non-Executive Director, plus reasonable expenses. Further details of the Non-Executive Directors' letters of appointment are set out in paragraph 7 of Part XIV *(Additional Information)* of this Document.

Strategic decisions

Members and responsibility

The Directors are responsible for carrying out the Company's objectives, implementing its business strategy and conducting its overall supervision. Acquisition, divestment and other strategic decisions are considered and determined by the Board.

The Board provides leadership within a framework of prudent and effective controls. The Board establishes the corporate governance values of the Company and has overall responsibility for setting the Company's strategic aims, defining the business plan and strategy and managing the financial and operational resources of the Company and reviewing the performance of the officers and management of the Company's business.

Unless required by applicable law or other regulatory process, no Shareholder approval will be sought by the Company in relation to the making of any Acquisition. Any Acquisition will be subject to Board approval.

Frequency of meetings

The Board schedules quarterly meetings and holds additional meetings, as and when required.

Corporate governance

The Board holds timely Board meetings as issues arise which require the attention of the Board. The Board is responsible for the management of the business of the Company, setting the strategic direction of the Company and establishing the policies of the Company. It is the Board's responsibility to oversee the financial position of the Company and monitor the business and affairs of the Company, on behalf of the Shareholders to whom they are accountable.

The primary duty of the Board is to act in the best interests of the Company at all times. The Board will also address issues relating to internal control and the Company's approach to risk management and has formally adopted an anti-corruption and bribery policy.

Dr Stephen Staley and Carl Kindinger are considered by the Board to be independent non-executive directors. The Board has established an audit committee, a remuneration committee and a conflicts committee, with formally delegated duties and responsibilities.

The Board intends, so far as appropriate given the Company's size and the constitution of the Board, to comply with the Corporate Governance Guidelines for Small and Mid-Size Quoted Companies published by the Quoted Companies Alliance.

Audit committee

The Company has an audit committee (the "**Audit Committee**"), which comprises Dr. Stephen Staley and Carl Kindinger, and has the primary responsibility for monitoring the quality of internal control and ensuring that the financial performance of the Company is properly measured and reported on and for reviewing reports from the Company's auditors relating to the Company's accounting and internal controls. The Audit Committee is also responsible for making recommendations to the Board on the appointment of auditors and the audit fee and for ensuring that the financial performance of the Company is properly monitored and reported. The Audit Committee meets not less than twice a year. The chair of the Audit Committee is Dr Stephen Staley.

Remuneration committee

The remuneration committee comprises Carl Kindinger and Dr. Stephen Staley and is responsible for the review and recommendation of the scale and structure of remuneration for senior management, including any bonus arrangements or the award of share options with due regard to the interests of the Shareholders and the performance of the Company.

Conflicts committee

The conflicts committee considers on behalf of the Board any actual or potential conflict of interest between any member of the Board and the Company in respect of the Admission and any future potential acquisitions. The conflicts committee will meet on an ad hoc basis as required. The conflicts committee comprises Dr Stephen Staley and Carl Kindinger.

Nomination committee

The Company does not have a nomination committee, as the Board does not consider it appropriate to establish such a committee at this stage of the Company's development. Decisions which would usually be taken by the nomination committee will be taken by the Board as a whole.

Share dealing code

The Company has adopted a share dealing code for persons discharging managerial responsibilities (as defined in article 3(1)(25) of MAR) and their persons closely associated (as defined in article 3(1)(26) of MAR), which complies with the MAR and the Company takes all reasonable steps to ensure compliance by PDMRs and their Persons Closely Associated.

PART X
THE PLACING

Introduction

On 14 February 2020 pursuant to the Placing, the Placees subscribed for an aggregate of 89,000,000 New Ordinary Shares which will be issued at the Placing Price of 4 pence per share to Placees, conditionally raising gross proceeds of £3,560,000 for the Company, subject to deduction of estimated fees and expenses of £255,000 (exclusive of VAT). Existing Shareholders, to the extent that they do not participate in the Placing, will be diluted by 82.28 per cent. and therefore will see a reduction in their share capital and voting rights of 82.28 per cent.

The Placing Price in the Placing is 4 pence, being 4 pence above nil par value of the Ordinary Shares.

The Company has received binding Placing Letters from potential Investors to subscribe for (and who will be allotted) 89,000,000 New Ordinary Shares in aggregate at the Placing Price. The irrevocable commitments of the proposed Investors under the Placing Letters are subject only to Admission on 28 February 2020 (or such later date as the Company may notify Investors), but in any event not later than 31 March 2020, and may not be withdrawn other than on a failure of the Company to achieve Admission by the prescribed long-stop date.

The Net Placing Proceeds to the Company amount to approximately £3,305,000, after deduction of fees and expenses payable by the Company which are related costs for the capital raise.

The Placing is being made by means of an offering of the New Ordinary Shares primarily to certain institutional investors in the United Kingdom and elsewhere in the EEA. In accordance with Listing Rule 14.3, at least 25 per cent. of the Ordinary Shares will be in public hands (as such term is defined in the Listing Rules).

The estimated Net Placing Proceeds are approximately £3,305,000 which the Company intends to apply in the following order of priority:

Morocco – Guercif	**£**
Well planning, design and environmental	121,465
Drill site civil works	38,750
Rig mobilisation/demobilisation	116,248
Drilling well to 2,000 meters inclusive casing, mud, wireline logging, MDT tool, directional survey, camp and well clean-up (20 day well)	1,550,338
Well supervision	52,500
Incorporating and running Moroccan branch company with in-country manager	46,510

Trinidad – CO2 EOR Inniss-Trinity (Company receives only a share of profits from production)	
FRAM HSE, well operations and management of downhole completions	21,648
Civil works and road maintenance for CO2 truck deliveries	51,801
New well heads and additional downhole equipment	64,448
Additional well workovers	31,679
Generator and installation	12,654
Expansion of CO2 injection to include up to 3 additional reservoirs and up to 3 additional wells; new well workovers and completions for CO2 EOR for new wells and reservoirs in AT-4 Block; additional CO2 delivery system and increased CO2 supply requirement for CO2 EOR expansion	339,711
CO2 injection Massy operator costs, security and standby C02 supply	77,052
Telecommunications	9,302
Real-time reservoir engineering and HSE monitoring	11,628
Safety Equipment	13,976
Well insurance	9,302
Corporate running costs 12 months	413,772
FCA prospectus costs	17,000
Costs of professional advice in relation to prospectus	146,983
Sub-Total	**3,146,767**

Contingency 5%	158,233
NET PROCEEDS TOTAL	**3,305,000**

Completion of the Placing will be announced via a regulatory news service, which is expected to take place at 8.00 a.m. on 28 February 2020.

Certain restrictions that apply to the distribution of this Document and the New Ordinary Shares being issued under the Placing in certain jurisdictions are described in this section. Certain selling and transfer restrictions are also contained in this Part.

When admitted to trading, the New Ordinary Shares will be registered with ISIN number JE00BFZ1D698 and SEDOL number BFZ1D69.

Terms and conditions of the Placing

Each Investor who applies to subscribe for the New Ordinary Shares under the Placing will be bound by these terms and conditions:

Agreement to acquire the New Ordinary Shares

Conditional on the Investor being allocated New Ordinary Shares, an Investor who has applied for New Ordinary Shares agrees to acquire those New Ordinary Shares (such number of New Ordinary Shares not to exceed the number applied for by such Investor) at the Placing Price. To the fullest extent permitted by law, each Investor acknowledges and agrees that it will not be entitled to exercise any remedy of rescission at any time. This does not affect any other rights an Investor may have. Each such Investor is deemed to acknowledge receipt and understanding of this Document and in particular the risk and investment warnings contained in this Document.

Payment for the New Ordinary Shares

Each Investor must pay the Placing Price for the New Ordinary Shares issued to the Investor in the manner directed by the Company.

If any Investor fails to pay as so directed by the Company, the relevant Investor's application for New Ordinary Shares may be rejected.

Representations, warranties and acknowledgements

Each Investor and, in the case of paragraph below, any person subscribing for or applying to subscribe for New Ordinary Shares, or agreeing to subscribe for New Ordinary Shares on behalf of an Investor will be deemed to represent and warrant to the Registrar and the Company that:

(a) in agreeing to subscribe for New Ordinary Shares under the Placing, the Investor is relying solely on this Document, any supplementary prospectus and any regulatory announcement issued by or on behalf of the Company or on or after the date hereof and prior to Admission, and not on any other information or representation concerning the Company or the Placing. The Investor agrees that none of the Company or the Registrar nor any of their respective officers or directors will have any liability for any other information or representation. The Investor irrevocably and unconditionally waives any rights it may have in respect of any other information or representation;

(b) the content of this Document is exclusively the responsibility of the Company and the Directors and neither one of the Registrar nor any person acting on their behalf nor any of their respective affiliates is responsible for or shall have any liability for any information, representation or statement contained in this Document or any information published by or on behalf of the Company, and none of the Registrar nor any person acting on its behalf nor any of their respective affiliates will be liable for any decision by an Investor to participate in the Placing based on any information, representation or statement contained in this Document or otherwise;

(c) it has not relied on any information given or representations, warranties or statements made by the Company, the Directors, the Registrar or any other person in connection with the Placing other than information contained in this Document and/or any supplementary prospectus or regulatory announcement issued by or on behalf of the Company on or after the date hereof and prior to Admission. The Investor irrevocably and unconditionally waives any rights it may have in respect of any other information or representation;

(d) if the Investor is in the United Kingdom, it is: (i) a person having professional experience in matters relating to investments who falls within the definition of "investment professionals" in Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (the "**Financial Promotions Order**"); or (ii) a high net worth body corporate, unincorporated association or partnership or trustee of a high value trust as described in Article 49(2) of the Financial Promotions Order, or is otherwise a person to whom an invitation or inducement to engage in investment activity may be communicated without contravening section 21 of FSMA;

(e) if the Investor is in any EEA State which has implemented the Prospectus Regulation, it is: (i) a legal entity which is a qualified investor as defined in article 2(e) of the Prospectus Regulation; or (ii) a legal entity which is otherwise permitted by law to be offered and issued New Ordinary Shares in circumstances which do not require the publication by the Company of a prospectus pursuant to Article 3 of the Prospectus Regulation or other applicable laws. If the Investor subscribes for New Ordinary Shares as a financial intermediary, as that term is used in the Prospectus Regulation, it further represents, warrants and undertakes that: (i) the New Ordinary Shares have not been and will not be acquired on behalf of, nor have they been nor will they be acquired with a view to their offer or resale to, persons in any EEA State other than qualified investors, as that term is defined in article 2(e) of the Prospectus Regulation; and (ii) where New Ordinary Shares have been acquired by it on behalf of persons in an EEA State other than qualified investors, the offer of those New Ordinary Shares to it is not treated under the Prospectus Regulation as having been made to such persons;

(f) it has complied with its obligations in connection with money laundering and terrorist financing under the Proceeds of Crime Act 2002, the Terrorism Act 2000 and the Money Laundering, Terrorist Financing and Transfer of Funds (Information on the Payer) Regulations 2017, or applicable legislation in any other jurisdiction (the "**Regulations**") and, if it is making payment on behalf of a third party, it has obtained and recorded satisfactory evidence to verify the identity of the third party as required by the Regulations;

(g) it is entitled to subscribe for the New Ordinary Shares under the laws of all relevant jurisdictions which apply to it; it has fully observed such laws and obtained all governmental and other consents which may be required under such laws and complied with all necessary formalities; it has paid all issue, transfer or other taxes due in connection with its acceptance in any jurisdiction; and it has not taken any action or omitted to take any action which will or

may result in any of the Company, the Director, the Registrar or any of their respective directors, officers, agents, employees or advisers acting in breach of the legal and regulatory requirements of any jurisdiction in connection with the Placing or, if applicable, its acceptance of or participation in the Placing;

(h) in the case of a person who agrees on behalf of an Investor, to subscribe for New Ordinary Shares under the Placing, that person represents and warrants that he has authority to do so on behalf of the Investor;

(i) it hereby acknowledges to the Registrar and the Company that the Investor has been warned that an investment in the New Ordinary Shares is only suitable for acquisition by a person who:

(i) has a significantly substantial asset base such that would enable the person to sustain any loss that might be incurred as a result of acquiring the New Ordinary Shares; and

(ii) is sufficiently financially sophisticated to be reasonably expected to know the risks involved in acquiring the New Ordinary Shares.

The Company will rely upon the truth and accuracy of the foregoing representations, warranties, acknowledgements and undertakings.

Acknowledgement

Each Investor and, in the case of paragraph above, any person subscribing for or applying to subscribe for New Ordinary Shares, or agreeing to subscribe for New Ordinary Shares on behalf of an Investor will be deemed to acknowledge to the Company that the Investor has been warned that an investment in the Shares is only suitable for acquisition by a person who:

(j) has a significantly substantial asset base such that would enable the person to sustain any loss that might be incurred as a result of acquiring the New Ordinary Shares; and

(k) is sufficiently financially sophisticated to be reasonably expected to know the risks involved in acquiring the New Ordinary Shares.

The Company will rely upon the truth and accuracy of the foregoing representations, warranties, acknowledgements and undertakings.

Supply and disclosure of information

If any of the Registrar or the Company or any of their agents request any information about an Investor's agreement to purchase New Ordinary Shares under the Placing, such Investor must promptly disclose it to them.

Miscellaneous

The rights and remedies of each of the Registrar and the Company under these terms and conditions are in addition to any rights and remedies which would otherwise be available to each of them and the exercise or partial exercise of one will not prevent the exercise of others.

On application, if an Investor is a discretionary fund manager, that Investor may be asked to disclose in writing or orally the jurisdictions in which its funds are managed or owned.

All documents will be sent at the Investor's risk. They may be sent by post to such Investor at an address notified to the Company.

Each Investor agrees to be bound by the Articles (as amended from time to time) once the New Ordinary Shares, which the Investor has agreed to acquire pursuant to the Placing, have been issued to the Investor.

The contract to purchase New Ordinary Shares under the Placing, the appointments and authorities mentioned herein and the representations, warranties and undertakings set out herein will be governed by, and construed in accordance with, English law. For the exclusive benefit of the Company and the Registrar, each Investor irrevocably submits to the exclusive jurisdiction of the English courts in respect of these matters. This does not prevent an action being taken against an Investor in any other jurisdiction.

In the case of a joint agreement to purchase New Ordinary Shares under the Placing, references to an "Investor" in these terms and conditions are to each of the Investors who are a party to that joint agreement and their liability is joint and several.

The Company expressly reserves the right to modify the Placing (including, without limitation, its timetable and settlement) at any time before closing.

Allocation

Multiple applications for New Ordinary Shares under the Placing will be accepted. A number of factors will be considered in deciding the basis of allocation under the Placing, including the level and nature of the demand for the New Ordinary Shares and the objective of establishing an Investor profile consistent with the long-term objective of the Company. The Company will notify Investors of their allocations. No dealings in New Ordinary Shares can take place prior to any allocations being made.

All New Ordinary Shares issued pursuant to the Placing will be issued, payable in full, at the Placing Price.

The New Ordinary Shares issued pursuant to the Placing will be issued in registered form and the currency of the securities issue is Pounds Sterling. It is expected that the New Ordinary Shares will be issued pursuant to the Placing on 28 February 2020.

Dealing Arrangements

Applications will be been made to the FCA for all the New Ordinary Shares to be listed on the Official List and to the London Stock Exchange for the Shares to be admitted to trading on the London Stock Exchange's main market (Standard List) for listed securities.

The expected date for settlement of such dealings will be 28 February 2020. All dealings between the commencement of conditional dealings and the commencement of unconditional dealings will be on a "when issued basis". If the Placing does not become unconditional in all respects, any such dealings will be of no effect and any such dealings will be at the risk of the parties concerned.

It is expected that unconditional dealings in the New Ordinary Shares will commence on the London Stock Exchange at 8.00 a.m. on 28 February 2020. This date and time may change.

It is intended that settlement of Shares allocated to Investors will take place by means of crediting New Ordinary Shares to relevant CREST stock accounts. Dealings in advance of crediting of the relevant CREST stock account shall be at the risk of the person concerned. When admitted to trading, the New Ordinary Shares will be registered with ISIN number JE00BFZ1D698 and SEDOL number BFZ1D69.

CREST

CREST is the system for paperless settlement of trades in listed securities operated by Euroclear. CREST allows securities to be transferred from one person's CREST account to another's without the need to use share certificates or written instruments of transfer.

The Articles permit the holding of Ordinary Shares in uncertificated form under the CREST system.

Application has been made for the New Ordinary Shares to be admitted to CREST with effect from the Placing. Accordingly, settlement of transactions in the New Ordinary Shares following the Placing may take place within the CREST System if any Shareholder (as applicable) so wishes. CREST is a voluntary system and holders of Ordinary Shares who wish to receive and retain share certificates will be able to do so. An Investor applying for New Ordinary Shares in the Placing may elect to receive New Ordinary Shares in uncertificated form if the Investor is a system member (as defined in the CREST Regulations) in relation to CREST.

PART XI
OPERATING AND FINANCIAL REVIEW (INCLUDING LIQUIDITY AND CAPITAL RESOURCES AND CAPITALISATION AND INDEBTEDNESS)

1 FINANCIAL POSITION

The financial information in respect of the Company included within this Part XI has been extracted, without adjustment, from Part XII (Financial Information on the Company) of this Document

If the Placing had taken place on 30 June 2019 (being the date to which the financial information contained in Part XII (*Financial Information on the Company*) of this Document was compiled) and the Placing were fully subscribed:

- the net assets of the Company would have increased by £3,305,000 (due to the receipt of the Net Placing Proceeds); and
- the Company's earnings would have decreased as a result of fees and expenses incurred in connection with the Placing.

2 OPERATING AND FINANCIAL REVIEW

The following operating and financial review contains financial information that has been extracted or derived without material adjustment from the Company's historical financial information for the years ended 31 December 2017, 31 December 2018 and the six month period ended 30 June 2019.

This discussion contains forward-looking statements, which, although based on assumptions that the Directors consider reasonable, are subject to risks and uncertainties which could cause actual events or conditions to differ materially from those expressed or implied by the forward-looking statements. Investors should read the notice in relation to forward-looking statements contained on page 32 of this Document.

The key risks and uncertainties, include, but are not limited to those described in Part II – Risk Factors beginning on page 13 of this Document.

2.1 Overview

The Company was incorporated on 19 December 2017 under the Jersey Companies Law and was admitted on the London Stock Exchange (Standard List) on 24 May 2018.

Details of the current issued shares of the Company are set out in paragraph 3 of Part XIV (Additional Information) of this Document. As at Admission, there is expected to be an aggregate of 197,172,169 Ordinary Shares in issue.

All of the issued New Ordinary Shares will be in registered form, and capable of being held in certificated or uncertificated form. The Registrar will be responsible for maintaining the share register. Temporary documents of title will not be issued. The ISIN of the Ordinary Shares is JE00BFZ1D698. The SEDOL number of the Ordinary Shares is BFZ1D69. The TIDM of the Ordinary Shares is PRD.

The Board may offer new Ordinary Shares by way of consideration as well as cash, in order to preserve the Company's cash for working capital and as a reserve against unforeseen contingencies including, for example, delays in collecting accounts receivable, unexpected changes in the economic environment and operational problems. For a detailed summary of the risks relating to the Company's business, please see *Part II – Risk Factors* of this Document.

RESULTS OF OPERATIONS FOR THE SIX MONTHS TO 30 JUNE 2019 COMPARED TO THE FINANCIAL YEAR ENDED 31 DECEMBER 2018 AND THE FINANCIAL YEAR ENDED 31DECEMBER 2017

The table below sets forth the Company's results of operations for the six months ended 30 June 2019 compared to the financial years ended 31 December 2018 and 31Decmber 2017:

CONTINUING OPERATIONS:

	Six months 30 June 2019 Unaudited	Year ended 31 December 2018 Audited	Year ended 31 December 2017 Audited
Revenue	**-**	**-**	**-**
Administrative expenses	**(472,273)**	**(761,302)**	**(414,370)**
Directors remuneration	(207,486)	(257,332)	(300,000)
Directors expenses	(59,111)	(76,787)	(16,980)
Non Executive Directors' remuneration	(32,500)	(39,011)	-
Listing costs	(53,692)	(180,346)	(30,928)
Secretarial and administration service provider	(41,962)	(64,080)	(13,522)
Legal and professional fees	(39,174)	(25,712)	-
Licencing options	-	(89,057)	(49,886)
Bank Guarantee fees	(23,948)	-	-
Other	(14,400)	(28,977)	(3,054)
Loan impairment/write off		**(32,171)**	**(34,276)**
Operating loss	**(472,273)**	**(793,473)**	**(448,646)**
Finance income	**-**	**1,012**	**492**
Finance expense	**(39,990)**	**-**	**-**
Loss for the year / period before taxation	**(512,263)**	**(792,461)**	**(448,154)**
Taxation	**-**	**-**	**-**
Loss for the period after taxation	**(512,263)**	**(792,461)**	**(448,154)**

Administrative Expenses

The Company incurred administrative expenses of £472,273 for the six month period to 30 June 2019, compared to £761,302 for the financial year ended 31 December 2018, and £414,370 for the financial year ended 31 December 2017. The Directors' remuneration comprises the majority of the costs incurred during the periods under review. The Company is in a phase where the acquisition of the Guercif Petroleum Agreement and the development of a CO2 EOR pilot project require intensive high-level input from the executive Directors, who are remunerated on an hourly basis and travel to Morocco

and Trinidad frequently. The licensing costs relate to payments required in order to maintain Corrib South and Ram Head.

The loan impairment in the periods to 31 December 2018 and 31 December 2017 were due to a loan provided by the Company to a licence partner before the Company's IPO to assist with meeting commitments for the Corrib South licence. This pre-IPO loan is repayable to the Company but has not been called to due to a lack of activity on the Corrib South licence. The Directors therefore deemed it prudent to impair the loan.

Finance Income and Expense

The Company received interest on bank balances of £1,012 for the financial year ended 31 December 2018, compared to the £492 received for the financial year ended 31 December 2017.

The £39,990 finance expense charge incurred in the period to 30 June 2019 relates to the accounting for funding costs of the CLN. This is described in more detail below under the paragraph headed "Cash Flow Analysis" in this Part XI.

Income Tax

There was no income tax charge for the six months period to 30 June 2019 and for the financial years ended 31 December 2018 and 31 December 2017 reflecting operating losses before tax in each of these periods.

Loss for the Period

The Company recorded a loss for the six months period to 30 June 2019 of £512,263, compared to a loss of £792,473 for the financial year ended 31 December 2018 and £448,154 for the financial year ended 31 December 2017. Such loss was caused due to the increase in administrative expenses as described under the paragraph headed "Administrative Expenses" above in this Part XI.

Cash Flow Analysis

The following table presents the Company's cash flow summary for the six months ended 30 June 2019 compared to the financial years ended 31 December 2018 and 31 December 2017:

Cash flows from operating activities			
Loss for the period before taxation	**(512,263)**	**(792,461)**	**(448,154)**
Adjustments for:			
Consultancy fees	**-**	**-**	**300,000**
Loans waived	**-**	**32,171**	**34,276**
Issue of share options	**-**	**54,519**	**-**
Finance expense	**39,990**	**-**	**-**
Finance income	**-**	**(1,012)**	**(492)**
Depreciation	**-**	**392**	**-**
Foreign exchange	**31,109**	**-**	**-**
Decrease/(Increase) in trade and other receivables	**(1,208,410)**	**24,383**	**(36,293)**
Increase in trade and other payables	**(686)**	**62,911**	**3,238**
Net cash used in operating activities	**(1,650,260)**	**(619,097)**	**(147,425)**
Cash flow from investing activities			
Purchase of exploration and evaluation assets	**(3,574)**	**-**	**-**
Purchase of computer equipment	**(999)**	**(4,014)**	**-**
Net cash generated from investing activities	**(4,573)**	**(4,014)**	**-**
Cash flows from financing activities			
Proceeds from issuance of shares, net of issue costs	**-**	**1,074,760**	**-**
Proceeds from issue of convertible loan notes, net of issue costs	**1,410,000**	**-**	**-**
Finance income received	**-**	**1,012**	**-**
Net cash generated from financing activities	**1,410,000**	**1,075,772**	**-**
Net increase/decrease in cash and cash equivalents	**(244,833)**	**452,661**	**(147,425)**
Cash and cash equivalents at the beginning of the year	**973,600**	**520,939**	**668,364**
Cash and cash equivalents at the end of the period / year	**728,767**	**973,600**	**520,939**

Net cash flows from operating activities

For the six months ended 30 June 2019 the Company's net cash generated from operating activities was a loss of £1,650,260 compared to a loss of £619,097 for the financial year ended 31 December 2018 and a loss of £147,425 for the financial year ended 31 December 2017. Such loss was due to an increase in receivables of £1,208,410 and administrative expenses of £472,273 for the six months ended 30 June

2019 compared to £761,302 for the financial year ended 31 December 2018 and £414,370 for the financial year ended 31 December 2017.

Net cash flows from investing activities

For the six months ended 30 June 2019 the Company's net cash used in investing activities was £4,573 compared to £4,014 for the financial year ended 31 December 2018 and £0 for the financial year ended 31 December 2017.

Net cash flows from financing activities

For the six months ended 30 June 2019 the Company's net cash generated from financing activities was £1,410,000 compared to £1,075,772, for the financial year ended 31 December 2018 and £0 for the financial year ended 31 December 2017.

For the six months ended 30 June 2019 cash generated through financing activities was attributable to the issuance of convertible loan notes pursuant to the CLN. The loan notes are convertible at the election of the Lender at 105% of the principal amount being converted. The conversion price is calculated as 90% of the volume weighted average share price of a Company's Ordinary Share as shown on the London Stock Exchange for the two trading days immediately preceding the notice of conversion from the Lender.

For the financial year ended 31 December 2018 cash generated through financing activities was attributable to issuances of Ordinary Shares.

Liquidity and Capital resources

The Company had a cash balance of £109,047 at 13 January 2020. The Company will use such cash plus part of the Net Placing Proceeds to fund the expenses of the Placing, including legal and professional fees, ongoing costs and expenses, the Joint Brokers' fees of £14,000 and an estimated annual audit fee of £15,000, all exclusive of VAT.

The costs and expenses of any further acquisition will likely comprise legal, financial and tax due diligence in relation to any target company; however, the Company would only reach this stage after the Directors have carried out an initial commercial review of the target and the Company has entered into a non-disclosure agreement and/or heads of terms. In addition to any share consideration used by the Company in relation to any acquisition, the Company may raise additional capital in connection with the consummation of that acquisition (dependent upon the size of such acquisition and the ability of the Company to satisfy the consideration in shares). Such capital may be raised through share issues (such as rights issues, open offers or private placings) or borrowings. The Company may also make an acquisition or fund part of any acquisition through share-for-share exchanges.

Although the Company envisages that any capital raised will be from new equity, the Company may also choose to finance all or a portion of an acquisition with debt financing. Any debt financing used by the Company is expected to take the form of bank financing, although no financing arrangements will be in place at Admission. The Company envisages that debt financing may be necessary if, for example, a target company has been identified but would require a certain amount of cash consideration in addition to, or instead of, share consideration.

Any associated debt financing (if any) for an acquisition will be assessed with reference to the projected cash flow of the target company or business and may be incurred at the Company level or by any subsidiary of the Company. Any costs associated with the debt financing will be paid with the proceeds of such financing.

If debt financing is utilised, there will be additional servicing costs. Furthermore, while the terms of any such financing cannot be predicted, such terms may subject the Company to financial and operating covenants or other restrictions, including restrictions that might limit the Company's ability to make distributions to Shareholders.

Substantially all of the Net Placing Proceeds is expected to be used for working capital. Following an acquisition, the Company's future liquidity will depend in the medium to longer term primarily on: (i) the profitability of any company or business it acquires; (ii) the Company's management of available cash; (iii) cash distributions on sale of existing assets; (iv) the use of borrowings, if any, to fund short-term liquidity needs; and (v) dividends or distributions from subsidiary companies.

The Company's capital resources comprise its share capital and reserves.

The Company's sources of cash following the Placing will be the Net Placing Proceeds, together with the monies raised by the Company prior to the Placing.

The Company may raise additional capital from time to time. Such capital may be raised through share issues (such as rights issues, open offers or private offers) or borrowings.

Although the Company envisages that any capital raised will be from new equity, the Company may also choose to utilise debt financing. Any debt financing used by the Company is expected to take the form of bank financing, although no bank financing arrangements are currently in place.

If debt financing is utilised, there will be additional servicing costs. Furthermore, while the terms of any such financing cannot be predicted, such terms may subject the Company to financial and operating covenants or other restrictions, including restrictions that might limit the Company's ability to make distributions to Shareholders.

2.2 ***Cash uses***

The Company's principal use of cash (including the Net Placing Proceeds) will be as working capital. The Company's current intention is to distribute free cash from its operational activities in Trinidad to Shareholders subject to the ongoing capex and working capital constraints necessary in relation to prudent financial management of its business operations and business development. The Company will only pay dividends to the extent that to do so is in accordance with the Jersey Companies Law and all other applicable laws. The Directors do not anticipate declaring any dividends in the short to medium term.

The estimated Net Placing Proceeds are approximately £3,305,000, which the Company intends to apply in the following order of priority:

Morocco – Guercif	**£**
Well planning, design and environmental	121,465
Drill site civil works	38,750
Rig mobilisation/demobilisation	116,248

Drilling well to 2,000 meters inclusive casing, mud, wireline logging, MDT tool, directional survey, camp and well clean-up (20 day well)	1,550,338
Well supervision	52,500
Incorporating and running Moroccan branch company with in-country manager	46,510
Trinidad – CO2 EOR Inniss-Trinity (Company receives only a share of profits from production)	
FRAM HSE, well operations and management of downhole completions	21,648
Civil works and road maintenance for CO2 truck deliveries	51,801
New well heads and additional downhole equipment	64,448
Additional well workovers	31,679
Generator and installation	12,654
Expansion of CO2 injection to include up to 3 additional reservoirs and up to 3 additional wells; new well workovers and completions for CO2 EOR for new wells and reservoirs in AT-4 Block; additional CO2 delivery system and increased CO2 supply requirement for CO2 EOR expansion	339,711
CO2 injection Massy operator costs, security and standby C02 supply	77,052
Telecommunications	9,302
Real-time reservoir engineering and HSE monitoring	11,628
Safety Equipment	13,976

Well insurance	9,302
Corporate running costs 12 months	413,772
FCA prospectus costs	17,000
Costs of professional advice in relation to prospectus	146,983
Sub-Total	**3,146,767**
Contingency 5%	158,233
NET PROCEEDS TOTAL	**3,305,000**

2.3 ***Deposit of Net Placing Proceeds***

The Net Placing Proceeds will be held in the bank accounts of the Company and will not be placed in any trust or escrow account. The Company will principally seek to preserve capital and therefore the yield on such deposits or instruments is likely to be low.

2.4 ***Capitalisation and indebtedness***

On 15 February 2019 the Company issued a convertible loan note in favour of Arato Global Opportunities LLC ("**Lender**") to raise £1.5 million to provide a refundable bank guarantee of US$1.5 million to be put in place in respect of the work programme agreed to be carried out by the Company under the terms of the Guercif Petroleum Agreement, and for general working capital purposes. The bank guarantee is refunded in full to the Company upon completion of the Guercif work programme.

The following table shows the Company's indebtedness ((distinguishing between guaranteed and unguaranteed, secured and unsecured indebtedness) as at 30 June 2019 and the Company's capitalisation as at 30 June 2019. The Company's capitalisation has been extracted without material adjustment from the unaudited interim results of the Company for the 6 month period ended 30 June 2019.

	As at 30 June 2019
	£'000
Total current debt	-
Guaranteed	-
Secured	-
Unguaranteed/unsecured	

-

Total non-current debt (excluding current portion of non-current debt)	**1,018**
Guaranteed	-
Secured	-
Unguaranteed/unsecured	1,018

Shareholders' equity

Share capital	1,934
Legal reserve	-
Other reserves	3,710
Total capitalisation	**5,644**

As at 17 February 2020, being the latest practicable date prior to the publication of this document, there has been no material change in the capitalisation of the Company since 30 June 2019.

The following table shows the Company's net indebtedness as at 31 December 2019.

	As at 31 December 2019
	£'000
Cash	110
Cash equivalent	-
Trading securities	-
Liquidity	110
Current financial receivable	**-**
Current bank debt	-
Current portion of non-current debt	38
Other current financial debt	**-**
Current financial debt	-
Net current financial indebtedness	**(72)**
Non-current bank loans	-
Bonds issued	-
Other non-current loans	899

Non-current financial indebtedness	**899**
Net financial indebtedness	**827**

The Company's indirect or contingent indebtedness at 31 December 2019 was £826,813.

2.5 **Accounting policies and financial reporting**

The Company's financial year end is 31 December, and its first set of audited annual financial statements published following the Placing will be for the period to 31 December 2019. The Company produces and publishes half-yearly financial statements as required by the Disclosure Guidance and Transparency Rules. The Company will present its financial statements in accordance with IFRS as adopted by the European Union.

PART XII

FINANCIAL INFORMATION ON THE COMPANY AND OTHER INFORMATION INCORPORATED BY REFERENCE

Audited financial information on the Company and its subsidiaries is published in the annual report for the year ended 31 December 2018. Historical financial information contained in the 2018 Annual Report is expressly incorporated by reference into this Document as detailed below.

The historical financial information referred to above was audited by PKF Littlejohn LLP. All reports were without qualification and contained no statements under section 498(2) or (3) of CA 2006 and were prepared in accordance with International Financial Reporting Standards and are being incorporated by reference.

The annual reports incorporated by reference, all of which have been filed with the Companies Registrar as required under CA 2006 and previously published as required by the Listing Rules and the 2018 Prospectus, are available on the Investor section of the Company's website at https://www.predatoroilandgas.com/.

The Company's unaudited interim accounts for the six months ended 30 June 2019 with comparative unaudited interim accounts for the six months ended 30 June 2019 are also incorporated by reference into this Document as detailed below. The Unaudited Interim Accounts have not been reviewed by the Group's auditor pursuant to the Financial Reporting Council guidance on "Review of Interim Financial Information".

This Prospectus should therefore be read and construed in conjunction with:

- the Annual Report and Accounts for the financial year ended 31 December 2018, together with the audit report thereon;
- the Unaudited Interim Accounts for the six months ended 30 June 2019; and
- the historical financial information contained in Part X of the 2018 Prospectus.

The table below sets out the sections of these documents which are incorporated by reference into, and form part of, this Prospectus, and only the parts of the documents identified in the table are incorporated into, and form part of, this Prospectus. The parts of these documents which are not incorporated by reference are either not relevant for Investors or are covered elsewhere in this Prospectus. To the extent that any part of any information referred to below itself contains information which is incorporated by reference, such information shall not form part of this Prospectus.

Reference Document	Information incorporated by Reference	Page numbers
Company unaudited interim results for the six months ended 30 June 2019	CEO operations report	Pages 1 to 3
	Chairman's statement	Page 3
	Interim management report	Pages 3 to 5
	Consolidated statement of comprehensive income	Pages 4 to 5
	Condensed consolidated statement of financial position	Page 5
	Condensed consolidated statement of changes in equity	Pages 5 to 6
	Condensed consolidated statement of cash flows	Page 6

	General information, basis of preparation, statement of compliance, going concern, cyclicality, accounting policies, areas of estimates and judgment	Pages 6 to 7
	Financial risk management, segmental analysis, earnings per share, trade and other receivables, cash balances, share capital, non-current liability, warrants, investments in subsidiaries, related party transactions, subsequent events	Pages 7 to 10
Company audited results for the year ended 31 December 2018	Chairman's statement	Pages 1 to 2
	Strategy	Pages 3 to 4
	Group strategic report	Pages 5 to 16
	Report of the directors	Pages 17 to 18
	Corporate governance report	Pages 20 to 23
	Directors' remuneration report	Pages 24 to 27
	Independent auditor's report	Pages 28 to 30
	Consolidated statement of comprehensive income	Page 31
	Consolidated statement of financial position	Page 32
	Consolidated statement of changes in equity	Page 33
	Consolidated statement of cash flows	Page 34
	Statement of accounting policies	Pages 35 to 39
	Notes to the financial statements	Pages 40 to 47
Prospectus published by the Company on 21 May 2018	Sections A, B, C, D and E of Part X (*Historical financial information*)	Pages 65 to 99
	Paragraph 13.9 of Part XIII	Pages 130 to 136

UNAUDITED PROFORMA CONSOLIDATED NET ASSET STATEMENT FOR THE GROUP

Set out below is an unaudited pro forma statement of net assets of the Group as at 30 June 2019. The unaudited pro forma statement of net assets of the Group as at 30 June 2019 has been prepared on the basis set out in the notes below and in accordance with the Group's accounting policies as adopted by the Group in its last audited financial statements. This has been prepared in line with the requirements of item 20.2 of Annex I and items 1 to 6 of Annex II of the Prospectus Regulation Rules to illustrate the impact of the Placing as if it had taken place on 30 June 2019.

The unaudited pro forma information has been prepared for illustrative purposes only and, by its nature, addresses a hypothetical situation and does not, therefore, represent the Group's actual financial position or results. Such information may not, therefore, give a true picture of the Group's financial position or results nor is it indicative of the results that may or may not be expected to be achieved in the future. The unaudited pro forma information is based on the unaudited net assets of the Group as at 30 June 2019 as incorporated by reference into this Part XII (Financial Information of the Company).

No adjustments have been made to take account of trading, expenditure or other movements subsequent to 30 June 2019, being the date of the last published balance sheet of the Group.

The unaudited pro forma information does not constitute financial statements within the meaning of section 434 of the Companies Act. Investors should read the whole of this Document and not rely solely on the summarised financial information contained in this Part XII.

Condensed consolidated statement of financial position

As at 30 June 2019

	30.06.2019 (unaudited) *Note 1*	Issue of New Ordinary Shares net of costs 30.06.2019 (unaudited) *Note 2*	Unaudited pro forma aggregated net assets of the Group 30.06.2019 (unaudited) *Note 3*
	£	**£**	**£**
Non-current assets			
Exploration and evaluation	**3,574**	-	**3,574**
Tangible fixed assets	**4,621**	-	**4,621**
	8,195	-	**8,195**
Current assets			
Trade and other receivables	**1,189,551**	-	**1,189,551**
Cash and cash equivalents	**728,767**	**3,305,000**	**4,033,767**
	1,918,318	**3,305,000**	**5,223,318**
Total assets	**1,926,513**	**3,305,000**	**5,231,513**
Non-Current liabilities			
Convertible loan notes	**1,018,605**	-	**1,018,605**
Current liabilities			
Trade and other payables	**69,584**	-	**69,584**
Total liabilities	**1,088,189**	-	**1,088,189**
Net Assets	**838,324**	**3,305,000**	**4,143,324**

Notes

The pro forma statement of net assets has been prepared on the following basis:

1. The unaudited net assets of the Group as at 30 June 2019 have been extracted without adjustment from the historical financial information which is incorporated by reference in this Part XII.

2. An adjustment has been made to reflect the proceeds of the placing of 89,000,000 New Ordinary Shares at an issue price of 4 pence per Ordinary Share net of an adjustment to reflect the payment in cash of admission costs in relation to the prospectus estimated at approximately £255,000 inclusive of any non-recoverable VAT.

3. No adjustments have been made to reflect the trading or other transactions, other than described above of the Group since 30 June 2019.

4. The pro forma statement of net assets does not constitute financial statements.

UNAUDITED PROFORMA INCOME STATEMENT FOR THE GROUP

Set out below is an unaudited pro forma income statement of the Group for the 6 months ended 30 June 2019. The unaudited pro forma income statement of the Group for the 6 months ended 30 June 2019 has been prepared on the basis set out in the notes below and in accordance with the Group's accounting policies as adopted in its last financial statements. This has been prepared in line with the requirements of item 20.2 of Annex I and items 1 to 6 of Annex II of the Prospectus Regulation Rules to illustrate the impact of the Placing as if it had taken place on 30 June 2019.

The unaudited pro forma information has been prepared for illustrative purposes only and, by its nature, addresses a hypothetical situation and does not, therefore, represent the Group's actual financial position or results. Such information may not, therefore, give a true picture of the Group's financial position or results nor is it indicative of the results that may or may not be expected to be achieved in the future. The unaudited pro forma information is based on the unaudited income statement of the Group's as at 30 June 2019 as shown in this Part XII (*Financial Information of the Company*) of this Document. No adjustments have been made to take account of trading, expenditure or other movements subsequent to 30 June 2019, being the date of the last published income statement of the Group.

The unaudited pro forma information does not constitute financial statements within the meaning of section 434 of the Companies Act. Investors should read the whole of this Document and not rely solely on the summarised financial information contained in this Part XII.

Consolidated statement of comprehensive income

For the 6 months to 30 June 2019

	30.06.2019 to 30.06.2019 *Note 1* (unaudited) £	No adjustments i.r.o Placing 30.06.2019 to 30.06.2019 (unaudited) £	Unaudited pro forma aggregated income statement Group as at 30.06.2019 to 30.06.2019 *Note 3* (unaudited) £
Administrative expenses	**(472,273)**		**(472,273)**
Operating loss	**(472,273)**		**(472,273)**
Finance income	**-**		**-**
Finance expense	**(39,990)**		**(39,990)**
Loss for the period before taxation	**(512,263)**		**(512,263)**
Taxation	**-**		**-**
Loss for the period after taxation	**(512,263)**		**(512,263)**
Other comprehensive income	**-**		**-**
Total comprehensive loss for the period attributable to the owner of the parent	**(512,263)**		**(512,263)**
Loss per share (in pence)	**(0.5)**		**(0.5)**

Notes

The pro forma income statement has been prepared on the following basis:

1. The unaudited income statement of the Group as at 30 June 2019 has been extracted without adjustment from the historical financial information which is incorporated by reference in this Part XII.

2. No adjustments have been made to reflect the trading or other transactions of the Group since 30 June 2019.

3. No adjustment has been made to reflect trading results of the Group since 30 June 2019.

REPORT ON THE UNAUDITED PRO FORMA NET ASSETS AND INCOME STATEMENT

Accountants &
business advisers

The Directors
Predator Oil & Gas Holdings Plc
Standard Bank House
47-49 La Motte Street
Jersey JE2 4SZ

Dear Sirs

Introduction

We report on the unaudited pro forma net assets and income statement at 30 June 2019 (the "**Pro Forma Financial Information**") set out in Part XII of this Prospectus, which has been prepared on the basis described in Part XII of this Document, for illustrative purposes only, to provide information about how the Placing might have affected the net assets presented on the basis of the accounting policies adopted by the Company in preparing the audited financial information for the period ended 30 June 2019. This report is required by Annex 1, Section 18, Item 18.4.1 of Commission Delegated Regulation (EU) 2019/980 and is given for the purpose of complying with that requirement and for no other purpose.

Responsibilities

It is the responsibility of the Directors of the Company to prepare the Pro Forma Financial Information in accordance with Annex 1, Section 18, Item 18.4.1 of Commission Delegated Regulation (EU) 2019/980.

It is our responsibility to form an opinion, in accordance with Annex 1, Section 18, Item 18.4.1 of Commission Delegated Regulation (EU) 2019/980, as to the proper compilation of the Pro Forma Financial Information and to report that opinion to you in accordance with Annex 1, Section 18, Item 18.4.1 of Commission Delegated Regulation (EU) 2019/980.

Save for any responsibility arising under PRR 5.3.2(2)(f) which we may have to those persons to whom this report is expressly addressed and which we may have to Shareholders of the Company as a result of the inclusion of this report in the Prospectus, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statements, required by and given solely for the purposes of complying with Annex 1, Section 1, Item 1.3 of Commission Delegated Regulation (EU) 2019/980, consenting to its inclusion in the Prospectus.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro Forma Financial Information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we have performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro Forma Financial Information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

Our work has not been carried out in accordance with auditing or other standards and practices generally accepted in jurisdictions outside the United Kingdom, including the United States of America, and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices.

Opinion

In our opinion:

(a) the Pro Forma Financial Information has been properly compiled on the basis stated; and

(b) such basis is consistent with the accounting policies of the Company.

Declaration

For the purposes of PRR 5.3.2(2)(f) we are responsible for this report as part of the Prospectus and declare that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the Prospectus in compliance with Annex 1, Section 1, Item 1.2 of Commission Delegated Regulation (EU) 2019/980.

Yours faithfully

PKF Littlejohn LLP
Reporting Accountant

1 Westferry Circus
Canary Wharf
London E14 4HD

19 February 2020

PART XIII
TAXATION

UK taxation

The following is based on the Directors' understanding of certain aspects of the law and published HM Revenue & Customs practice currently in force in the UK applicable to the Company and to persons who are resident in the UK for tax purposes, who hold Ordinary Shares as an investment and who are not employees of the Group. The information below is based on current legislation or proposals as at the date of this Document. There can be no guarantee that the tax position or the proposed tax position at the date of this Document or at the time of an investment in Ordinary Shares will endure indefinitely as tax rates, bases and reliefs can change.

Shareholders should consult their professional advisers on the possible tax and other consequences of their subscribing for, purchasing, holding, selling or redeeming Ordinary Shares under the laws of their country of incorporation, establishment, citizenship, residence or domicile.

If you are in any doubt about your tax position, or if you may be subject to tax in a jurisdiction other than the UK, you should consult your professional adviser.

The Company

As a company which has its registered office and its central control and management outside of the UK, the Company should not be resident in the UK for UK tax purposes. The Directors intend to conduct the affairs of the Company in a manner such that it does not become resident in the UK for UK tax purposes. Accordingly, on the basis that the Company is not tax resident in the UK and provided that the Company does not carry on a trade in the UK (whether or not through a branch, agency or permanent establishment situated therein), the profits arising from the Company's activities should not be subject to UK corporation tax (other in practice than to any UK withholding tax deducted from interest or certain other income which has a UK source). However, it cannot be guaranteed that these conditions will be met at all times.

The Shareholders

This section provides general guidance for Shareholders who are UK resident for tax purposes only and hold their Shares as investments. The liability to UK taxation of chargeable gains will depend on the individual circumstances of each Shareholder.

UK Offshore Fund Rules

The Directors consider that the Company should not constitute an ''offshore fund'' for the purposes of Part 8 of the Taxation (International and Other Provisions) Act 2010, on the basis that a reasonable investor holding shares should not expect to be able to realise all or part of their investment in the shares on a basis calculated entirely or almost entirely by reference to the net asset value of the assets of the Company or an index of any description, otherwise than on a liquidation or winding up and the Company is not designed to be wound up on a stated or determinable date. Accordingly, individual and corporate Shareholders should not be liable to United Kingdom income tax or corporation tax on income respectively in respect of any gain on disposal of the shares, but they may, depending on their individual circumstances be liable to United Kingdom capital gains tax or corporation tax on chargeable gains realised on the disposal of their Shares.

On the basis that the Company should not constitute an ''offshore fund'' for UK tax purposes and provided it is not an open-ended investment company, the ''bond fund'' rules will not apply such that the

shares will not be treated as creditor loan relationships for corporate Shareholders as set out in section 490 of the Corporation Tax Act 2009, and distributions on the shares should not be treated as interest for income tax purposes for individual Shareholders as set out in section 378A of the Income Tax (Trading and Other Income) Act 2005.

Tax on Chargeable Gains

A disposal of Ordinary Shares by a Shareholder who is resident in the UK for tax purposes, or who is not resident but carries on business in the UK through a branch, agency or permanent establishment with which their investment in the Company is connected may give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of capital gains, depending on the Shareholder's circumstances and subject to any available exemption or relief.

For individual Shareholders, capital gains tax (tax year 2019/2020) at the rate of 10 per cent. (for basic rate taxpayers) or 20 per cent. (for higher or additional rate taxpayers) may be payable on any gain. Individuals may benefit from certain reliefs and allowances (including an annual exemption, which presently exempts the first £12,000 (tax year 2019/2020) of gains from tax) depending on their circumstances.

Individual Shareholders who are resident but not domiciled in the UK and who elect to be taxed on a remittance basis should not, however, be subject to tax on any gain, or offshore income gain, realised on a disposal of their interest in the Company provided that gain, or offshore income gain, is not remitted to the UK and subject, in the case of 'longer-term' UK residents to payment of the appropriate remittance basis charge in the relevant tax year. UK pension funds should also be unaffected by the Offshore Fund Regulations, since their exemption from UK tax on capital gains should extend to gains treated as income under these provisions.

Shareholders that are bodies corporate resident in the UK for taxation purposes will benefit from indexation allowance which, in general terms, reduces or eliminates a chargeable gain, but does not generate or increase an allowable loss. Such Shareholders will be subject to corporation tax on chargeable gains at their applicable corporation tax rate of up to 19 per cent for the financial year commencing 1 April 2019. Indexation allowance was frozen for corporation tax purposes from 31 December 2017, therefore the indexation figures that companies can deduct only cover the movement in RPI from the date of acquisition of the asset to 31 December 2017.

Taxation of Dividends

Dividends

An individual Shareholder resident in the UK for UK tax purposes will receive a £2,000 tax free dividend allowance. The dividend tax rates for any dividend income above £2,000 are 7.5 per cent for basic rate taxpayers, 32.5 per cent for higher rate taxpayers and 38.1 per cent for additional rate taxpayers.

Shareholders that are bodies corporate resident in the UK for tax purposes, and that are not "small companies", may be able to rely on Part 9A of the Corporation Tax Act 2009 to exempt dividends from being chargeable to UK corporation tax if they hold less than 10 per cent of the issued share capital of the Company, and are entitled to less than 10 per cent of the profits or assets of the Company available for distribution to holders of the issued share capital on a winding up, or another exemption is applicable. The exemptions are not comprehensive and are subject to anti-avoidance rules.

Shareholders within the charge to UK corporation tax which are "small companies" (as that term is defined in section 931S of the Corporation Tax Act 2009) will be liable to corporation tax on dividends paid to them by the Company because the Company is not resident in a "qualifying territory" for the

purposes of the legislation contained in the Corporation Tax Act 2009. Jersey is a non-qualifying territory for this purpose.

Withholding Tax

The Company is not required to withhold UK tax at source from any dividends paid by it to Shareholders.

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

No UK stamp duty of SDRT will arise on the issue of shares.

A charge to UK stamp duty could arise on an instrument of transfer in respect of the Ordinary Shares (or a document evidencing a transfer) if it were executed in the UK for a consideration in excess of the *de minimis* threshold (currently £1,000). Where a charge to UK stamp duty arises this will generally be at the rate of 0.5 per cent, of the consideration for the transfer, rounded up to the nearest £5, under current law. Therefore, no UK stamp duty will be payable on a transfer of Shares, provided that all instruments effecting or evidencing the transfer are not executed in the UK, no matters or actions relating to the transfer are or are to be performed in the UK, and no property situation in the UK relates to the transfer.

Since the Ordinary Shares are issued by a company incorporated outside the UK and the Company does not intend to maintain a register of shareholders in the UK, the Ordinary Shares should not be regarded as "chargeable securities" for the purposes of UK SDRT and, accordingly, no SDRT should be chargeable in respect of agreements for their transfer.

Individual Savings Accounts ("ISAs")

Shares acquired pursuant to the Placing will not be eligible to be held in an ISA. Shares acquired in the Placing or in the secondary market should be eligible for inclusion in a stocks and shares ISA so long as they are either listed or on a recognised stock exchange or are admitted to trading on a recognised stock exchange, subject to applicable subscription limits. Investors resident in the UK who are considering acquiring Shares in the Placing or in in the secondary market are recommended to consult their own tax and/or investment advisers in relation to the eligibility of the Shares for ISAs. The annual ISA investment allowance is £20,000 for the tax year 2019/2020.

Other UK tax considerations

Controlled Foreign Companies

United Kingdom resident companies having an interest in the Company, such that broadly 25 per cent. or more of the Company's profits for an accounting period could be apportioned to them, may be liable to United Kingdom corporation tax in respect of their share of the Company's profits in accordance with the provisions of Part 9A of the Taxation (International and Other Provisions) Act 2010 relating to controlled foreign companies. These provisions only apply if the Company is controlled by United Kingdom resident persons (corporate and individuals).

Section 3 of the Taxation of Chargeable Gains Act 1992 (''Section 3'')

The attention of persons resident in the United Kingdom for taxation purposes is drawn to the provisions of Section 3. Section 3 applies to a ''participator'' for UK taxation purposes (which includes a Shareholder, or an "indirect participator" which includes as Shareholder in a company which itself is a "participator") if at any time when a gain accrues to the Company which constitutes a chargeable gain for those purposes, the Company is itself controlled by a sufficiently small number of persons so as to

render the Company a body corporate that would, were it to have been resident in the United Kingdom for taxation purposes, be a ‘‘close’’ company for those purposes.

The provisions of Section 3 could, if applied, result in any such person who is a ‘‘participator’’ in the Company being treated for the purposes of United Kingdom taxation of chargeable gains as if a part of any chargeable gain accruing to the Company had accrued to that person directly, that part being equal to the proportion of the gain that corresponds to that person’s proportionate interest in the Company as a ‘‘participator’’. No liability under Section 3 could be incurred by such a person however, where the amount apportioned to such person and to persons connected with him does not exceed one quarter of the gain.

Transfer of Assets Abroad

The attention of individuals ordinarily resident in the UK is drawn to sections 714 to 751 of the Income Tax Act 2007, which contains provisions for preventing avoidance of income tax by transactions resulting in the transfer of income to persons (including companies) abroad and may render them liable to taxation in respect of undistributed income and profits of the Company.

Transactions in Securities

The attention of Shareholders is drawn to anti-avoidance legislation in Chapter 1, Part 13 of the Income Tax Act 2007 and Part 15 of the Corporation Tax Act 2010 that could apply if Shareholders are seeking to obtain tax advantages in prescribed conditions. If any prospective investor is in doubt as to his taxation position, he is strongly recommended to consult an independent professional adviser without delay.

PART XIV
ADDITIONAL INFORMATION

1 RESPONSIBILITY

1.1 The Directors, whose names appear on page 6, and the Company accept responsibility for the information contained in this Document. To the best of the knowledge of the Directors and the Company, the information contained in this Document is in accordance with the facts and this Document contains no omission likely to affect its import.

1.2 PKF Littlejohn LLP accepts responsibility for its accountant's reports incorporated by reference in Part XII of this Document. To the best of the knowledge of PKF Littlejohn LLP, the information contained in each of such accountant's reports is in accordance with the facts and that this Document contains no omission likely to affect its import.

1.3 SLR accepts responsibility for each of its four Competent Person's Reports set out at Part XVIII of this Document. To the best of the knowledge of SLR, the information contained in each of the four competent person's reports is in accordance with the facts and that this Document contains no omission likely to affect its import.

2 THE COMPANY

2.1 The Company was incorporated on 19 December 2017 as a public company with limited liability under the Jersey Companies Law with registered number 125419 under the name Predator Oil & Gas Holdings Plc.

2.2 The Company was listed on the London Stock Exchange (Standard List) on 24 May 2018. The Company's LEI is 213800L7QXFURBFLDS54.

2.3 The Company is not regulated by the FCA or any financial services or other regulator. The Company is subject to the Listing Rules and the Disclosure and Transparency Rules (and the resulting jurisdiction of the UK Listing Authority), to the extent such rules apply to companies with a Standard Listing pursuant to Chapter 14 of the Listing Rules.

2.4 The principal legislation under which the Company operates, and pursuant to which its shares which comprise the Shares have been created, is the Jersey Companies Law and the subordinate legislation made under it. The Company operates in conformity with its constitution.

2.5 The Company's registered office is at 3rd Floor, Standard Bank House, 47 – 49 La Motte Street, Jersey JE2 4SZ. The Company's telephone number is +44 1534 834 600.

2.6 As at 17 February 2020, being the latest practicable date prior to publication of this Document, the Company had three wholly-owned subsidiaries, POGV (registered number 110127), PGV (registered number 127451 and POGT (registered number 125427), both being private companies with limited liability incorporated in Jersey.

3 SHARE CAPITAL

3.1 The Ordinary Shares are freely transferable ordinary shares of no par value and are denominated in UK Sterling, subject to the Jersey Companies Law and the Articles.

3.2 The following table shows the shareholders that hold three per cent or more of the issued and fully paid shares of the Company at the date of this Document and/or immediately following Admission (as applicable). All shares have no par value.

	As at the date of this Document			As at the date of Admission		
	Number of Ordinary Shares	**Nominal value £**	**Percentage of issued ordinary share capital**	**Number of Ordinary Shares**	**Nominal value £**	**Percentage of Enlarged Share Capital**
Paul Griffiths	44,773,294	Nil	41.39%	45,085,794	Nil	22.87%
Sanderson Capital Partners Limited	-	Nil	-	10,625,000	Nil	5.39%
Global Prime Partners Nominee Ltd	-	Nil	-	10,125,000	Nil	5.14%
Ronald Pilbeam	7,273,294	Nil	6.72%	7,585,794	Nil	3.84%
Spreadex Limited	-	Nil	-	7,500,000	Nil	3.80%
The Bank Of New York (Nominees) Limited	5,587,400	Nil	5.17%	5,587,400	Nil	3.00%
Pershing Nominees Limited (a/c BICLT)	5,349,415	Nil	4.95%	5,349,415	Nil	2.71%
Hargreaves Lansdown (Nominees) Limited (a/c 15942)	5,077,438	Nil	4.69%	5,077,438	Nil	2.57%

Hargreaves Lansdown (Nominees) Limited (a/c VRA)	4,864,252	Nil	4.50%	4,864,252	Nil	2.47%

3.3 Assuming that the Placing is fully taken up, the issued and fully paid shares of the Company is expected to be as shown in the following table:

	Issued and Credited as Fully Paid	
Class of Share	**Number**	**Nominal value**
Ordinary	197,172,169	£Nil

3.4 The following is a summary of the changes in the issued Ordinary Share capital of the Company since its incorporation:

Date	**Issued Share Capital**	**Description**
19 December 2017	1	Issue of subscription share
21 March 2018	53,708,550	Issue of further shares
24 May 2018	100,137,150	Placing of new ordinary shares in relation to the IPO
12 April 2019	102,104,038	Conversion of the CLN
13 May 2019	103,545,702	Conversion of the CLN
28 May 2019	105,247,953	Conversion of the CLN
10 September 2019	106,730,309	Conversion of the CLN
25 October 2019	108,172,169	Conversion of the CLN

3.5 The Company resolved by special resolution passed on 13 June 2019 that (amongst other things):

3.5.1 the Directors were duly authorised in accordance with the Articles to exercise all the powers of the Company to allot, issue, convert any security into, grant options over or otherwise dispose of equity securities (as that term is defined in the Articles) as if the pre-emption rights set out in the Articles did not apply to such process described above, such power to be limited up to a total of 100,000,000 New Ordinary Shares provided always that the authorities conferred on the Directors described in (a), (b) and (c) above shall expire at the earlier of the conclusion of the next annual general meeting of the Company after the passing of the resolution and 15 months from the passing of the resolution but, in each case, during this period, the Company may make offers and enter into agreements which would, or might, require equity securities to be allotted after the authority ends and the Directors may allot equity securities under any such offer or agreement as if the authority had not ended.

3.6 Other than the issue of Ordinary Shares pursuant to the Placing, the Company has no present intention to issue any new shares in the share capital of the Company.

3.7 Save as disclosed in this Document:

- the Company holds no Ordinary Shares in treasury;
- no share or loan capital of the Company has been issued or is proposed to be issued;
- no person has any preferential subscription rights for any shares of the Company;
- no share or loan capital of the Company is unconditionally to be put under option; or
- no commissions, discounts, brokerages or other special terms have been granted by the Company since its incorporation in connection with the issue or sale of any share or loan capital of the Company.

3.8 All Ordinary Shares in the capital of the Company are in registered form.

3.9 The New Ordinary Shares will be listed on the Official List and will be traded on the main market of the London Stock Exchange. The Ordinary Shares are not listed or traded on, and no application has been or is being made for the admission of the Ordinary Shares to listing or trading on, any other stock exchange or securities market.

3.10 As at the date of this Document, the Company has indebtedness in relation to the CLN, as further described in paragraph 14.7 below.

4 MEMORANDUM AND ARTICLES OF ASSOCIATION

4.1 Memorandum of Association

The Memorandum of the Company does not limit the objects, powers and activities of the Company.

4.2 Articles of Association

For the purpose of this paragraph 4.2 of this Part XIV, the following definitions shall apply:

"special resolution" a resolution of the Company passed as a special resolution in accordance with the Jersey Companies Law by a majority of three-quarters of the votes cast in that resolution.

The Articles were adopted by the Company on 11 January 2018 and amended on 11 November 2018 and include, *inter alia,* provisions to the following effect:

4.2.1 *Stated capital account*

The Board may establish a stated capital account in accordance with the Jersey Companies Law for each class of issued shares. A stated capital account may be expressed in any currency.

4.2.2 *Alteration of share capital*

The Company may, by special resolution, alter its share capital or reduce its stated capital account in any manner permitted by the Jersey Companies Law.

4.2.3 ***Purchase of own shares***

Subject to, and in accordance with, the Jersey Companies Law and without prejudice to any special rights attached to any class of shares, the Company may purchase any of its own shares of any class (including, without limitation, redeemable shares) in any way and at any price and may hold such shares as treasury shares.

4.2.4 ***Share rights***

Subject to the Jersey Companies Law 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 and restrictions as the Board may decide.

No share issued by the Company shall have a nominal value. Subject to the Jersey Companies Law and to any rights attached to any existing shares, the Company may issue shares which are to be redeemed, or are liable to be redeemed at the option of the Company or the member, on such terms and in such manner as may be determined by the Board.

4.2.5 ***Allotment of securities and pre-emption rights***

Subject to the provisions of the Jersey Companies Law, the Articles and any resolution of the Company passed by the Company conferring authority on the directors to allot shares and without prejudice to any rights attached to existing shares, all unissued shares are at the disposal of the Board.

Although the Jersey Companies Law does not provide any statutory pre-emption rights, the Articles provide that the Company shall not allot any equity securities (as defined in the Articles, and which excludes shares to be allotted pursuant to an employees' share scheme) for cash to a person unless it has made an offer to each person who holds relevant shares or employee shares to allot to him on the same or more favourable terms a proportion of those securities which is, as nearly as is practical, equal to the proportion of the total number of relevant shares and relevant employee shares held by him. The Company may by special resolution give the Board power to allot equity securities as if the above pre-emption rights do not apply or as if such rights apply with such modifications as the Board may determine.

4.2.6 ***Share certificates***

Every member whose name is entered on the Company's register of members as a holder of any certificated shares is entitled, without payment, to one certificate in respect of all shares of any class held by him. In the case of joint holders, delivery of a certificate to one of the joint holders shall be sufficient delivery to all.

The Company's board may permit title to some or all of the shares of any class to be evidenced otherwise than by a certificate and title to such shares to be transferred in accordance with the rules of a relevant system pursuant to which title to units of a security can be evidenced and transferred in accordance with the CREST Regulations, without a written instrument. The Articles are consistent with CREST membership.

4.2.7 ***Lien Call and Formation***

The Company shall have a first and paramount lien on every share (not being a fully paid share) for all monies payable to the Company (whether presently payable or not) in respect of that share. The Board may at any time waive any lien or declare any share to be wholly or in part exempt from the relevant provisions of the Articles. The Company's lien on a share shall extend to any amount payable in respect of it.

The Board may from time to time make calls upon the members in respect of any monies unpaid on their shares. Each member shall (subject to being given at least 14 clear days' notice specifying where and when payment is to be made) pay to the Company the specified amount called on his shares. If any call or instalment of a call remains unpaid on or after the due date for payment, the person from whom it is due and payable shall pay interest on the amount unpaid from the day it became due and payable until it is paid. Interest shall be paid at a fixed rate, fixed by the terms of the allotment of the share or in the notice of call or if no rate is fixed, the rate determined by the Board.

The Board may also (on giving not less than 14 clear days' notice requiring payment of the amount unpaid together with interest and costs incurred by the Company) forfeit the shares by resolution of the Board. The forfeiture shall include all dividends or other monies payable in respect of the forfeited share. The forfeited shares may be sold, re-allotted or otherwise disposed of by the Board in such manner as it determines.

4.2.8 ***Variation of rights***

Subject to the provisions of the Jersey Companies Law and to any rights attached to existing shares (and except in the case where there is only one holder of the issued shares in which case 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 in such manner (if any) as may be provided by those rights, or in the absence of any such provision, either with the written consent of the holders of not less than three-quarters in number of the issued shares of the class or the sanction of a special resolution passed at a separate general meeting of the holders of shares of the class duly convened and held.

4.2.9 ***Transfer of shares***

Without prejudice to any power of the Company to register as a shareholder a person to whom the right to any share has been transmitted by operation of law, the instrument of transfer of a certificated share may be in the 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.

In respect of shares which are in uncertificated form, any member may transfer all or any such shares subject to the CREST Regulations, by means of a relevant system, provided that legal title to such shares shall not pass until the transfer is entered in the register.

The Board may refuse to register the transfer of a share in certificated form unless the instrument of transfer: (i) is lodged at the registered office of the Company or at another place appointed by the Board, accompanied by the certificate for the share

to which it relates and such other evidence as the Board may reasonably require to show the right of the transferor to make the transfer; (ii) is in respect of only one class of shares; and (iii) is in favour of not more than four transferees. In respect of shares for the time being in uncertificated form, the Board may refuse to register a transfer of shares which would require shares to be held jointly by more than four persons or which would be in breach of any laws or requirements or which, in the opinion of the Board, might result in the Company incurring any liability to taxation or suffering any pecuniary or regulatory disadvantage.

If the Board refuses to register a transfer of shares, it shall send the transferee notice of its refusal within two months after the date on which the instrument of transfer was lodged with the Company or, in the case of uncertificated shares, the instruction from Euroclear was received by the Company.

No fee shall be charged for the registration of any instrument of transfer or other document relating to or affecting the title to a share, or for making any other entry in the register.

4.2.10 ***Disclosure of interests in shares***

The provisions of DTR 5 are generally incorporated in the Articles and apply to the Company so that members are required under the Articles to notify the Company of the percentage of their voting rights when they hold more than 3 per cent, of the Company's shares through their direct or indirect holding of financial instruments falling within paragraph 5.1.3R of DTR 5 (or a combination of such holdings) and of any changes to such interest through a single percentage level. A shareholder must make the notification without delay (and in any event within 2 business days) after becoming, or becoming aware of the event or change.

If any member fails to comply with these requirements, the directors may, by notice to the holder of the shares, suspend their rights as to voting, dividends and transfer. During the period of such suspension, any dividend or other amount payable in respect of the shares shall be retained by the Company without any obligation to pay interest thereon.

The directors have the power, by giving notice, to require any member to disclose to the Company the identity of any person (other than the member) who is interested in the shares held by the member or who has been at any time during the preceding three years been so interested, in both cases together with details of the nature of such interest. If any member has been duly served with such a notice and has not supplied the information required within the prescribed period, the Company may serve a direction notice directing that the member shall not be entitled to vote at a general meeting or meeting of the holders of any class of shares of the Company or exercise any other right conferred by membership in relation to the meetings of the Company or holders of any class of shares of the Company. Where a direction notice has been served on a member in relation to shares representing at least 0.25 per cent, of the issued shares of that class, the notice may additionally direct that any dividend or other money which would otherwise be payable may be retained by the Company and transfers of such default shares will be restricted.

4.2.11 ***General meetings***

The Board shall convene and the Company shall hold general meetings as annual general meetings in accordance with the Jersey Companies Law. The Board may convene general meetings whenever it thinks fit.

The quorum for a general meeting is two persons (not representing the same corporation or appointed as proxy for the same member).

At least 21 clear days' notice shall be given of annual general meetings and at least 14 clear days' notice shall be given of all other general meetings, other than annual general meetings. The notice shall specify the day, time and place of the meeting and the general nature of the business to be transacted and, in the case of an annual general meeting, shall specify the meeting as such.

For the purpose of determining whether a person is entitled as a member to attend or vote at a meeting, and how many votes such person may cast, the Board may specify in the notice of the meeting a time not more than 48 hours before the time fixed for the meeting by which a person must be entered on the register in order to have the right to attend or vote at the meeting.

The Board may resolve to enable members entitled to attend a general meeting to do so by simultaneous attendance and participation by means of a video conference or any machinery and a person so participating shall be deemed to be present at the meeting and shall be entitled to vote and be counted in a quorum for so long as he is able to speak to, hear and see the other participants.

A director shall, notwithstanding that he is not a member, be entitled to attend and speak at any general meeting and at any separate meeting of the holders of any class of shares in the Company.

The chairman may, with the consent of a meeting at which a quorum is present, and if directed by the meeting, adjourn the meeting from time to time.

4.2.12 ***Voting***

All resolutions put to the vote of a general meeting shall be decided upon by a show of hands unless before, or on the declaration of the results of, the show of hands a poll is duly demanded. Subject to the provisions of the Jersey Companies Law, a poll may be demanded by: (i) the chairman, (ii) at least five members having the right to vote on the resolution, (iii) member(s) representing not less than one-tenth of the total voting rights of all the members having the right to vote on the resolution, or (iv) member(s) holding shares conferring a right to vote on the resolution being shares on which an aggregate sum has been paid up of not less than one- tenth of the total sum paid up on all the shares conferring that right.

Subject to any rights or restrictions attached to any shares, on a show of hands, every member who is present in person (or by a duly authorised representative) or by proxy shall have one vote. On a poll, every member present in person (or by a duly authorised representative) or by proxy shall have one vote for every share of which he is the holder. A member may appoint more than one proxy.

No member shall be entitled to vote at a general meeting or at a separate meeting of the holders of any class of shares unless all monies presently payable by him or in respect of his shares in the Company have been paid.

In the case of joint shareholders only, the vote of the senior joint holder shall be accepted.

In the case of an equality of votes, whether on a show of hands or on a poll, the chairman of the meeting shall be entitled to a second or casting vote in addition to any other vote he may have.

4.2.13 ***Appointment of directors***

Unless otherwise determined by ordinary resolution, the number of directors (other than alternate directors) shall not be subject to any maximum, but shall not be less than two in number.

Directors may be appointed by ordinary resolution or by the Board.

Subject to the provisions of the Jersey Companies Law, the Board may appoint one or more of their number to the office of managing director or to any other executive office of the Company and may enter into an agreement or arrangement with any director for his services to the Company or for the provision by him of any services outside the scope of the ordinary duties of a director. Any such appointment, agreement or arrangement may be made on such terms, including without limitation terms as to remuneration, as the Board determines.

Any director (other than an alternate director) may appoint any other director, or any other person willing to act, to be an alternate director.

4.2.14 ***No share qualification***

A director shall not be required to hold any shares in the capital of the Company by way of qualification.

4.2.15 ***Election and re-election of directors at annual general meetings***

At each annual general meeting, the following directors are to be proposed for election or re-election as directors: (i) each person who was appointed a director by the Board after the previous annual general meeting, (ii) each person who has continued to be a director since the first of the three previous annual general meetings without being elected or re-elected as a director in the meantime, and (iii) any other director selected by the Board for re-election. If a resolution for the election or re-election as a director of a person who was a director at the commencement of an annual general meeting is put to the vote at that meeting but not passed, that person will cease to be a director.

4.2.16 ***Remuneration of Directors***

Unless otherwise determined by the Company by ordinary resolution, the emoluments of the directors shall be determined by the Board and shall not exceed an aggregate amount of £150,000 in any financial year of the Company (such fees being distinct from any salary, remuneration or other amount payable to a director pursuant to any other provisions of the Articles). Subject to the Jersey Companies

Law and the Articles, the Board may arrange for part of a fee payable to a director to be provided in the form of fully paid shares in the Company.

Any director nominated to hold any appointment or executive office with the Company, or who otherwise performs special services at the request of the Board which, in the opinion of the Board, go beyond the ordinary duties of a director, may be paid such extra remuneration as the Board may determine.

The directors shall be paid all travelling, hotel, and other expenses properly incurred by them in connection with their attendance at meetings of the Board or committees of the Board, general meetings or separate meetings of the holders of any class of shares or of debentures of the Company or otherwise in connection with the discharge of their duties as a director.

The Board may provide benefits, whether by the payment of gratuities or pensions or by insurance or otherwise, for any past or present director of the Company or any of its subsidiary undertakings or any body corporate associated with any of them, and for any member of his family (including a spouse and a former spouse) or any person who is or was dependent on him, and may (as well before as after he ceases to hold such office or appointment) contribute to any fund and pay premiums for the purchase or provision of any such benefit.

4.2.17 ***Powers of Directors***

Subject to the provisions of the Jersey Companies Law, the memorandum of association, the Articles and to any directions given by special resolution, the business of the Company shall be managed by the Board which may exercise all powers of the Company.

The Board may delegate any of its powers to any committee consisting of one or more directors and/or one or more persons who are not directors. The Board may also delegate any of its powers to any director holding any other executive office or any other person(s) as the Board may consider appropriate.

4.2.18 ***Borrowing powers***

The Board may exercise all of the borrowing powers of the Company without limit

4.2.19 ***Proceedings of Directors***

A director may, and the secretary at the request of a director shall, call a meeting of the Board by giving no less than 72 hours' notice of the meeting (or such shorter notice period as is unanimously agreed by the directors) to each director.

Questions arising at a meeting shall be decided by a majority of votes. In the case of an equality of votes, the chairman shall have a second or casting vote. A director who is also an alternate director shall be entitled, in the absence of his appointor, to a separate vote on behalf of his appointor in addition to his own vote.

The quorum for the transaction of the business of the Board shall be two or such greater number as may be fixed by the Company in general meeting from time to time. A person who holds office only as an alternate director shall, if his appointor is not present, be counted in the quorum.

A resolution in writing signed by all the directors entitled to receive notice of a meeting of the Board or of a committee of the Board (and/or other persons to whom the director have delegated any of their powers pursuant to the Articles) shall be valid and effectual as if it had been passed at a meeting of the Board or (as the case may be) a committee of the Board (and/or other persons) duly convened and held.

A person entitled to be present at a meeting of the Board or of a committee of the Board shall be deemed to be present for all purposes if he is able, by means of a conference telephone or any machinery which allows all persons participating in the meeting to speak to and hear each other, and shall be entitled to vote and be counted in a quorum for so long as he is able to speak to and hear the other participants.

4.2.20 ***Permitted interests of directors***

Every director shall disclose to the Company all interests which are required to be so disclosed by virtue of the provisions of the Jersey Companies Law. The disclosure shall be made in any manner allowed or directed by the Jersey Companies Law.

Subject to the Jersey Companies Law and the Articles and provided that he has disclosed to the Board the nature and extent of any interest of his, a director notwithstanding his office may:

(a) be or become a director or officer of, or otherwise interested in, any company promoted by the Company or in which the Company may be interested or as regards which it has any power of appointment, and shall not be liable to account to the Company or the members for any remuneration, profit or other benefit received by him as a director or officer of or from his interest in the other company;

(b) hold any other office or place of profit within the Company or any of its subsidiaries (except that of auditor of the Company or auditor of its subsidiaries) in conjunction with the office of director for such period and upon such other terms as the Board may decide, and may be paid such extra remuneration for doing so as the Board decides, and either in addition to or in substitution of any remuneration provided for by or pursuant to any other provision of the Articles;

(c) act by himself or his firm in a professional capacity for the Company or any of its subsidiaries (otherwise than as auditor of the Company or auditor of any of its subsidiaries) and he or his firm shall be entitled to remuneration for professional services as if he were not a director; and

(d) be a party to, or otherwise interested in, any contract, transaction, arrangement or proposal with the Company (or any of its subsidiaries) or in which the Company (or any of its subsidiaries) is otherwise interested and shall not, by reason of his office, be accountable to the Company for any benefit which he derives from any such office or appointment or from any such contract, transaction, arrangement or proposal or from any interest in any such body corporate and no such transaction or arrangement shall be liable to be avoided on the ground of such interest or benefit.

4.2.21 ***Right to vote***

Except as otherwise provided in the Articles, a director may not vote on or be counted in the quorum in respect of any resolution of the Board or a committee of the Board relating to any contract, transaction, arrangement or proposal in which he has an interest which is a material interest, but such prohibition shall not apply to a resolution concerning:

(a) the giving of any guarantee, security or indemnity in respect of money lent or obligations incurred by him or any other person for the benefit of the Company (or any of its subsidiaries);

(b) the giving of any guarantee, security or indemnity in respect a debt or obligation of the Company (or any of its subsidiaries) for which the director has assumed responsibility in whole or in part, and whether alone or jointly with others;

(c) where the Company (or any of its subsidiaries) is offering securities in which offer the director is or may be entitled to participate as a holder of securities or in the underwriting or sub-underwriting of which the director is to or may participate;

(d) any contract, transaction, arrangement or proposal affecting any other body corporate in which he is interested (directly or indirectly and whether as an officer, shareholder, creditor or otherwise), provided that he does not to his knowledge hold an interest representing 1 per cent, or more of any class of the equity share capital of such body corporate (or through any third party body corporate through which his interest is derived) or of the voting rights available to members of the relevant body corporate (and such interest being deemed for the purposes of the Article to be a material interest in all circumstances);

(e) any act or thing done or to be done in respect of any arrangement for the benefit of the employees of the Company (or any of its subsidiaries) under which he is not accorded as a director any privilege or advantage not generally accorded to the employees to whom such arrangement relates; or

(f) any matter connected with the purchase or maintenance for any director of insurance against any liability.

If a question arises at a meeting as to the materiality of a director's interest (other than the interest of the chairman of the meeting) or as to the entitlement of a director to vote or be counted in the quorum and the question is not resolved by his voluntarily agreeing to abstain from voting or being counted in the quorum, the question shall be referred to the chairman and his decision in relation to such director's interest shall be conclusive and binding on all concerned.

If a question arises at a meeting as to the materiality of the interest of the chairman of the meeting or as to the entitlement of the chairman to be counted in the quorum and the question is not resolved by his voluntarily agreeing to abstain from voting or being counted in the quorum, the question shall be decided by a resolution of the directors (excluding the chairman) present at the meeting.

4.2.22 ***Indemnity of officers***

The Jersey Companies Law restricts indemnities or exemptions from liability given by Jersey companies to their directors and officers. In general, directors and officers of a Jersey company cannot be exempted from or receive an indemnity in respect of any liability which would otherwise attach to that director or officer under law by reason of the fact that they are or were a director or officer of the company. There are exceptions to this restriction, in particular in respect of proceedings where the director or officer is not held liable or the matter is discontinued, where the director or officer acted in good faith in the best interests of the company and in respect of any liability for which the company normally maintains insurance.

The Articles provide that a director, alternate director, secretary or other officer (present or former) shall be indemnified out of the assets of the Company to the fullest extent this is permissible under the Jersey Companies Law, against any loss or liability incurred by him by reason of being or having been such an officer.

4.2.23 ***Dividends and other distributions***

Subject to the provisions of the Jersey Companies Law, the Company may by ordinary resolution declare dividends in accordance with the respective rights of the members, but no such dividend shall exceed the amount recommended by the Board.

Subject to the provisions of the Jersey Companies Law, the Board may pay interim dividends if it appears to the Board to be justified by profits of the Company available for distribution.

A general meeting declaring a dividend may, on the recommendation of the Board, direct that the dividend shall be satisfied wholly or partly by the distribution of assets and, where any difficulty arises in regard to the distribution, the directors may settle the same and in particular may issue fractional certificates and fix the value for distribution of any assets and may determine that cash shall be paid to any member upon the basis of the value so fixed in order to adjust the rights of members and may vest any assets in trustees.

Except as otherwise provided by the rights attached to shares, all dividends shall be declared and paid *pro rata* amongst the shares on which the dividend is declared. If any share is issued on terms providing that it shall rank for dividend as from a particular date, that share shall rank for dividend accordingly.

The Board may deduct from any dividend or other monies payable to a member by the Company on or in respect of any shares all sums of money (if any) presently payable by him to the Company on account of calls or otherwise in respect of shares of the Company in respect of that share.

Any dividend or other monies payable in respect of a share may be paid by direct debit or bank transfer, or cheque or warrant sent by post to the registered address of the person entitled.

No dividend or other monies payable in respect of a share shall bear interest against the Company, unless otherwise provided by the rights attached to the share.

Any dividend which has remained unclaimed for 10 years from the date on when it became due for payment shall, if the Board so resolves, be forfeited and cease to remain owing by the Company.

4.2.24 ***Capitalisation of profits and reserves***

The Board may before the declaration of a dividend on the shares set aside any part of the profits of the Company, such sums as it thinks proper which shall, at the discretion of the Board, be applicable for any purpose to which the profits or reserves may be properly applied and pending such application, may at the like discretion, be employed in the business of the Company and invested in such investments as the Board may from time to time think fit.

4.2.25 ***Distribution of assets in a liquidation***

If the Company is wound up, the directors or the liquidator (as the case may be) may, with the sanction of a special resolution of the Company and any other sanction required by the Jersey Companies Law, divide the whole or any part of the assets of the Company among the members *in specie* and/or vest the whole or any part of the assets in trustees upon such trusts for the benefit of the members as he (or they) may determine, but no member shall be compelled to accept any assets upon which there is a liability.

The Jersey Companies Law provides that, subject to any enactment as to the order of payment of debts, the Company's property on a winding up will be applied in satisfaction of the Company's liabilities as they fall due and any remaining property of the Company will be distributed among the members according to their rights and interests in the Company.

5 DIRECTORSHIPS AND INTERESTS

5.1 In addition to their directorships of the Company and the Subsidiaries, the Directors are, or have been, members of the administrative, management or supervisory bodies ("directorships") or partners of the following companies or partnerships, at any time in the five years prior to the date of this Document:

	Current Directorships	**Previous Directorships**
Paul Griffiths	Petro-Celtex Consultancy Limited	
Ronald Pilbeam	Wykeham West Managers (Pty) Ltd. (registered in South Africa)	Ignition Brazil Fund #2 Limited (registered in Jersey) Ignition Brazil Fund #3 Limited (registered in Jersey)* Ignition Brazil Social and Affordable Housing Fund #1

		Limited (registered in Jersey)*
		Mafula Energy Limited (registered in Zambia)
Dr Stephen Staley	Staley Limited	Cold Gold Company Limited
	Derwent Resources Limited	Fastnet Oil and Gas Plc (now Amryt Pharma Plc)
	88 Energy Limited (registered in Western Australia)	Fastnet Oil & Gas (Ireland) Ltd (registered in the Republic of Ireland)
		Upland (Ksar Hadada) Limited
		Upland (S Tunisia) Limited
		Upland (Saouaf) Limited
		Upland (N Tunisia) Limited
		Upland Resources (UK Onshore) Limited
		Upland Resources Limited (registered in the British Virgin Islands)
		Upland Resources (Sarawak) Sdn. Bhd. (registered in Malaysia)
Carl Kindinger	Kindinger International Investments (Pty) Limited	Vast Resources Romania Limited

* These companies were liquidated in May 2014, by way of a planned liquidation.

5.2 As at the date of this Document none of the Directors:

5.2.1 has any convictions in relation to fraudulent offences for at least the previous five years;

5.2.2 has been associated with any bankruptcy, receivership or liquidation while acting in the capacity of a member of the administrative, management or supervisory body or of senior manager of any company for at least the previous five years; or

5.2.3 has been subject to any official public incrimination and/or sanction of him by any statutory or regulatory authority (including any designated professional bodies) or has ever been disqualified by a court from acting as a director of a company or from acting as a member of the administrative, management or supervisory bodies of an issuer or from acting in the management or conduct of the affairs of any issuer for at least the previous five years.

6 DIRECTORS' AND OTHER INTERESTS

6.1 Save as disclosed below, none of the Directors, nor any member of their immediate families has or will have on or following Admission any interests (beneficial or non-beneficial) in the shares of the Company.

	Immediately prior to Admission		Immediately following Admission	
Director	**No. of Shares**	**Percentage of Issued Shares**	**No. of Shares**	**Percentage of Enlarged Issued Share Capital**
Paul Griffiths*	44,773,294	41.39	45,085,794	22.87
Ronald Pilbeam	7,273,294	6.72	7,585,794	3.84
Carl Kindinger	1,661,962	1.54	1,661,962	0.84
Stephen Staley**	357,100	0.33	669,600	0.34

*Paul Griffiths has a beneficial interest in Celtex Exploration Services Ltd. which holds 1,785,714 ordinary shares in the share capital of the Company

**Stephen Staley has a beneficial interest in Pershing Nominees Limited, which holds 5,349,415 ordinary shares in the share capital of the Company.

6.2 As at the date of this Document, the Directors and their respective Connected Persons hold the following options or unissued Ordinary Shares of the Company:

Director	Number of Options	Exercise Price
Paul Griffiths	4,000,000	2.8 pence
Ronald Pilbeam	4,000,000	2.8 pence
Dr. Stephen Staley	1,000,000	2.8 pence

For the avoidance of doubt, under the existing share option scheme, there are 10,000,000 options, all of which have been granted to Directors and their respective Connected Persons, including 1,000,000 options granted to Sarah Cope, former non-executive director and Chairman, which the Board agreed should remain in place following Sarah Cope's resignation from the Board and departure from the Company.

The Board shall at all times use its reasonable endeavours to keep available sufficient authorised but unissued Shares to satisfy the exercise of all Options which the Board has determined will be satisfied by the issue of Shares.

6.3 Save as disclosed in paragraph 6.1, immediately following Admission, no Director will have any interest, whether beneficial or non-beneficial, in the share or loan capital of the Company.

6.4 Save for the Directors and their connected persons (within the meaning of section 252 of the Companies Act), at the date of this Document and/or immediately following the Placing (as applicable), so far as the Directors are aware, no person is directly or indirectly interested in more than three per cent. of the issued Ordinary Shares other than as set out below:

	As at the date of this Document			As at the date of Admission		
	Number of Ordinary Shares	**Nominal value £**	**Percentage of issued ordinary share capital**	**Number of Ordinary Shares**	**Nominal value £**	**Percentage of Enlarged Share Capital**
Sanderson Capital Partners Limited	-	Nil	-	10,625,000	Nil	5.39%
Global Prime Partners Nominee Ltd	-	Nil	-	10,125,000	Nil	5.14%
Spreadex Limited	-	Nil	-	7,500,000	Nil	3.80%
The Bank Of New York (Nominees) Limited	5,587,400	Nil	5.17%	5,587,400	Nil	3.00%
Pershing Nominees Limited (a/c BICLT)	5,349,415	Nil	4.95%	5,349,415	Nil	2.71%
Hargreaves Lansdown (Nominees) Limited (a/c 15942)	5,077,438	Nil	4.69%	5,077,438	Nil	2.57%
Hargreaves Lansdown (Nominees) Limited (a/c VRA)	4,864,252	Nil	4.50%	4,864,252	Nil	2.47%

The Company has advised that Paul Formanko is the beneficiary of one of the nominee companies referred to above.

6.5 Immediately following Admission, as a result of the Placing, the following persons will have an interest, directly or indirectly, in at least three per cent. of the voting rights attached to the

Company's issued Ordinary Shares. Such persons will be required to notify such interests to the Company in accordance with the provisions of Chapter 5 of the Disclosure Guidance and Transparency Rules, and such interests will be notified by the Company to the public:

Shareholder	No. of Ordinary Shares	Percentage of Enlarged Share Capital
Paul Griffiths	45,085,794	22.87%
Ronald Pilbeam	7,585,794	3.84%
Sanderson Capital Partners Limited	10,625,000	5.39%
Global Prime Partners Nominee Ltd	10,125,000	5.14%
Spreadex Limited	7,500,000	3.80%
The Bank of New York (Nominees) Limited	5,912,400	3.00%

6.6 As at 17 February 2020, (being the latest practicable date prior to the publication of this Document), the Company was not aware of any person or persons who, directly or indirectly, jointly or severally, exercise or could exercise control over the Company nor is it aware of any arrangements, the operation of which may at a subsequent date result in a change in control of the Company.

6.7 Those interested, directly or indirectly, in three per cent. or more of the issued Ordinary Shares of the Company do not now, and, following the Placing and Admission, will not, have different voting rights from other holders of Ordinary Shares.

7 DIRECTORS' CONTRACTS

Agreements in respect of the Directors' services

7.1 Paul Griffiths

The Company has entered into a consultancy agreement dated 18 May 2018 with Petro-Celtex Consultancy Limited ("**Petro-Celtex**") under which Petro-Celtex is to provide the services of Paul Griffiths as Chief Executive of the Company, on a part-time basis (120 hours in each calendar month). Under the consultancy agreement, Petro-Celtex is entitled to a fee of £80,000 per annum (plus VAT, if applicable) for the basic 120 hours per calendar month, £1,200 per 8 hour day (plus VAT, if applicable) for each additional day or part day in excess of the first 120 hours in any calendar month, up to an annual cumulative cap of 320 hours in a calendar year, supplemented by 250 hours effective only for the year ending 31 December 2019, and reimbursement of all reasonable expenses. The consultancy agreement may be terminated at any time by 3 months' prior written notice served by either party. Paul Griffiths has entered into a side letter dated 18 May 2018 with the Company confirming that the terms of this consultancy agreement will be binding on him as an individual.

The Company has established a share option scheme that became effective on Admission for a long term incentive plan for the award of share options subject to certain oil production targets

being reached and sustained by the Company for a period of not less than thirty calendar days. The share option scheme shall include Paul Griffiths as a beneficiary.

Paul Griffiths has also entered into a letter of appointment dated 21 December 2017 with the Company in respect of his continued appointment as a director of the Company with effect from Admission, but with no additional fee payable to him over and above the fee referred to in the consultancy agreement above. The continued appointment of Paul Griffiths as a director of the Company on the terms of such appointment letter is (subject to limited exceptions) for an initial period of 12 months following Admission and thereafter subject to termination by either party on three months' written notice. In addition the Company may forthwith terminate Paul Griffiths' appointment as a director of the Company for, amongst other things, a material breach by Petro-Celtex of its obligations under the consultancy agreement referred to above and Paul Griffiths may terminate such appointment for a material breach by the Company of its obligations under the consultancy agreement referred to above.

7.2 **Ronald Pilbeam**

The Company has entered into a consultancy agreement dated 18 May 2018 with Ronald Pilbeam to provide the services of Ronald Pilbeam as project development director of the Company, on a part-time basis (75 hours in each calendar month). Under the consultancy agreement, Ronald Pilbeam is entitled to a fee of £50,000 per annum (plus VAT, if applicable) for the basic 75 hours per calendar month, £1,000 per 8 hour day (plus VAT, if applicable) for each additional day or part day in excess of the first 75 hours in any calendar month, up to an annual cumulative cap of 400 hours in a calendar year, supplemented by 315 hours effective only for the year ending 31 December 2019, and reimbursement of all reasonable expenses. The consultancy agreement may be terminated at any time by 3 months' prior written notice served by either party.

The Company has established a share option scheme that became effective on Admission for a long term incentive plan for the award of share options subject to certain oil production targets being reached and sustained by the Company for a period of not less than thirty calendar days. The share option scheme shall include Ronald Pilbeam as a beneficiary.

Ronald Pilbeam has also entered into a letter of appointment dated 19 March 2018 with the Company in respect of his continued appointment as a director of the Company with effect from Admission, but with no additional fee payable to him over and above the fee referred to in the consultancy agreement above. The continued appointment of Ronald Pilbeam as a director of the Company on the terms of such appointment letter is (subject to limited exceptions) for an initial period of 12 months following Admission and thereafter subject to termination by either party on three months' written notice. In addition the Company may forthwith terminate Ronald Pilbeam's appointment as a director of the Company for, amongst other things, a material breach by Ronald Pilbeam of his obligations under the consultancy agreement referred to above, and Ronald Pilbeam may terminate such appointment for a material breach by the Company of its obligations under the consultancy agreement referred to above.

Non-Executive Directors

7.3 **Dr Stephen Staley**

Dr Stephen Staley has entered into a non-executive letter of appointment dated 18 May 2018 with the Company in respect of his appointment as a director of the Company. Dr Staley's appointment is conditional on Admission. Under the terms of the appointment letter, Dr Staley is entitled to a fee of £30,000 per annum, such fee to accrue on a daily basis and is payable in

equal monthly instalments in arrears on the last business day of each month (or as otherwise agreed). The appointment as a Non-Executive Director of the Company is subject to termination by other party on three months' written notice.

7.4 **Carl Kindinger**

The Company entered into a consultancy agreement dated 21 September 2018, and revised on 1 September 2019 with Carl Kindinger to provide financial consultancy advice and services in relation to the Company's exploration for and exploitation of oil and gas resources, on a part time-basis (100 hours in each calendar month). Under the consultancy agreement, Carl Kindinger is entitled to a fee of £70,000 per annum (plus VAT, if applicable). The consultancy agreement may be terminated at any time by 30 days' prior written notice served by either party.

Carl Kindinger has also entered into a letter of appointment dated 19 July 2019 with the Company in respect of his continued appointment as a director of the Company with effect from Admission, with an additional fee of £25,000 per annum payable to him under this letter of appointment. The continued appointment of Carl Kindinger as a director of the Company on the terms of such appointment letter is (subject to limited exceptions) for 3 years from the day of appointment and subject to termination by either party on three months' written notice. In addition the Company may forthwith terminate Carl Kindinger's appointment as a director of the Company for, amongst other things, a material breach by Carl Kindinger of his obligations under the consultancy agreement referred to above, and Carl Kindinger may terminate such appointment for a material breach by the Company of its obligations under the consultancy agreement referred to above.

Under the letter of appointment, Carl Kindinger shall be entitled to participate in the Company's option scheme.

8 WORKING CAPITAL

The Company is of the opinion that the working capital available to the Group, taking into account the Net Placing Proceeds, is sufficient for the present requirements of the Group, that is, for at least the 12 months from the date of this Document.

9 SIGNIFICANT CHANGE

There has been no significant change in the financial position or the financial performance of the Company since 30 June 2019, being the end of the last period for which interim unaudited financial information has been published.

10 LITIGATION

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) since the Company's incorporation which may have, or have had in the recent past, significant effects on the financial position or profitability of the Company.

11 CITY CODE

The City Code applies to the Company. Under Rule 9 of the City Code, if:

11.1 a person acquires an interest in shares in the Company which, when taken together with shares already held by him or persons acting in concert with him, carry 30% or more of the voting rights in the Company; or

11.2 a person who, together with persons acting in concert with him, is interested in not less than 30% and not more than 50% of the voting rights in the Company acquires additional interests in shares which increase the percentage of shares carrying voting rights in which that person is interested,

the acquirer and, depending on the circumstances, his 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 any interests in the Ordinary Shares by the acquirer or his concert parties during the previous 12 months.

12 MATERIAL CONTRACTS

The following are all of the contracts (not being contracts entered into in the ordinary course of business) that have been entered into by the Group in the two years immediately preceding the date of this Document which: (i) are, or may be, material to the Company or the Group; or (ii) contain obligations or entitlements which are, or may be, material to the Company or the Group as at the date of this Document:

12.1 Placing and Broker Agreements

12.1.1 Optiva Placing Agreement

The Optiva Placing Agreement dated 18 May 2018, entered into between the Company (1), the then directors of the Company (2) and Optiva (3) pursuant to which, subject to certain conditions, Optiva agreed to use reasonable endeavours to procure placees for Ordinary Shares to be issued pursuant to the placing in connection with the 2018 IPO. In consideration for its services under the Optiva Placing Agreement, Optiva received from the Company a placing commission and warrants.

The Company and the directors gave customary warranties and undertakings to Optiva and the Company agreed to provide customary indemnities to Optiva.

The Placing Agreement was not renewed following the initial 12 months contract period and therefore was terminated on 30 May 2018. Warrants granted to Optiva under the Placing Agreement remain in effect.

12.1.2 Novum Placing Agreement

The Novum Placing Agreement dated 18 May 2018, entered into between the Company (1) the then directors of the Company (2) and Novum (3) pursuant to which, subject to certain conditions, Novum agreed to use its reasonable endeavours to procure Placees for Ordinary Shares to be issued pursuant to the placing in connection with the 2018 IPO. In consideration for its services under the Novum Placing Agreement, Novum received from the Company a placing commission, warrants and an annual broker retainer fee of £25,000 plus VAT.

The Company and the directors gave customary warranties and undertakings to Novum and the Company agreed to provide customary indemnities to Novum.

Warrants granted Novum under the Placing Agreement remain in effect.

12.1.3 Novum Sole Placing Agent Agreement

The Novum Sole Placing Agreement dated 9 January 2019, entered into between the Company (1), the then directors of the Company (2) and Novum (3) pursuant to which, subject to certain conditions, Novum agreed to use its reasonable endeavours to procure a fundraise via either debt or equity of up to £1,500,000 by way of the issue of new shares in the capital of the Company.

In consideration for its services under the Novum Sole Placing Agreement, Novum received from the Company a placing commission and warrants.

The Company and the then directors of the Company gave customary warranties and undertakings to Novum and the Company agreed to provide customary indemnities to Novum.

Warrants granted Novum under the Placing Agreement remain in effect.

12.1.5 **2020 Placing Agreement**

A placing agreement dated in 14 February 2020 entered into between (1) the Company, (2) Novum and (3) Optiva pursuant to which Optiva and Novum have agreed to use their reasonable endeavours to procure Placees for the New Ordinary Shares to be issued pursuant to the Placing.

The 2020 Placing Agreement is conditional upon, *inter alia*, Admission occurring by 8.00 a.m. on 28 February 2020 (or such later date not being later than 31 March 2020, as the Company, Optiva and Novum may agree).

In consideration for its services under the 2020 Placing Agreement, Optiva will receive:

- a commission of £105,000; and
- conditional on the Company obtaining new shareholder approval for the allotment and issue of such Ordinary Shares, which will be sought following Admission, warrants over 1,875,000 Ordinary Shares exercisable at the Placing Price. The Ordinary Shares issued pursuant to the exercise of these warrants will therefore only be issued following Admission and therefore do not form part of the New Ordinary Shares.

In consideration for its services under the 2020 Placing Agreement, Novum will receive:

- a commission of £146,300;
- the issue to Novum of 2,375,000 Ordinary Shares at the Placing Price (the value of such Ordinary Shares being £95,000 in aggregate) following Admission, to be issued conditional on the Company obtaining new Shareholder approval; and
- conditional on the Company obtaining new shareholder approval for the allotment and issue of such Ordinary Shares, warrants over 2,575,000 Ordinary Shares exercisable at the Placing Price. The Ordinary Shares issued pursuant to the exercise of these warrants will therefore only be issued following Admission and therefore do not form part of the New Ordinary Shares.

12.2 **Lock-in and Orderly Market Agreements**

12.2.1 The Directors, Carl Kindinger, and the Company entered into a lock-in and orderly market agreement dated 18 May 2018 pursuant to which each of the Directors and Mr Kindinger agreed that for a 12 month period from 24 May 2018 (now expired)

they will not offer, sell, contract to sell, pledge or otherwise dispose of any Shares which they hold directly or indirectly in the Company. The orderly market agreement is for 6 months after 24 May 2019. These restrictions are subject to usual and customary exceptions relating to estate planning or transfers to affiliates, transfers of any Shares acquired in an open market transaction after the date of Admission, or acceptance of a general offer made to all Shareholders on equal terms.

The orderly market agreement has been extended for twelve months after 24 May 2019.

12.2.2 The Company, Novum and Arato entered into an orderly market agreement pursuant to which Arato covenanted to the Company and to Novum that it will not effect any disposal of shares already held or issued pursuant to the CLN during the 12 months from Admission except in accordance with the usual and customary exceptions and having followed the procedure detailed in the agreement.

The Company has agreed to issue to Arato 2,500,000 Ordinary Shares at the Placing Price in consideration for Arato waiving the requirement pursuant to the CLN that the Company pay to Arato up to 25 per cent. of the Placing funds in cash. These Ordinary Shares will be issued following Admission, conditional on the Company obtaining new Shareholder approval for such issue, and do not form part of the New Ordinary Shares.

12.3 **Irish licensing option agreements**

12.3.1 **Non-exclusive offshore petroleum prospecting licence no.13/16**

A non-exclusive offshore petroleum prospecting licence granted by the Minister for Communications, Climate Action and Environment in Ireland ("**Irish Minister**") in favour of POGV. This licence is issued under Section 9 of the Petroleum and Other Minerals Development Act 1960 as applied by Section 4(2) of the Continental Shelf Act 1968.

The area covered by this licence is set out in the map annexed to this licence and includes the territorial seas (excluding any parts in respect of which an exclusive petroleum exploration licence, reserved area licence or petroleum lease is in force) and parts of the internal waters of the State detailed in Schedule 1 (the "**Licensed Area**"). POGV agrees to engage in prospecting for petroleum in the Licensed Area.

This licence is valid from 1 November 2016 for two years, unless revoked or terminated sooner in accordance with its terms. POGV may give one month's notice in writing at any time to surrender or terminate this licence. On expiry of this licence the Irish Minister may grant a one-year extension where requested by POGV in writing. An annual licence fee is payable in advance by POGV to the Irish Minister, the first year's fee being €7,601.

During the term POGV will carry out any scheme of prospecting agreed with the Irish Minister. POGV will not be in breach where circumstances outside of its control prevent the prospecting. POGV shall follow the Rules and Procedures Manual for Offshore Petroleum Exploration Operations issued by the Irish Minister.

POGV is granted the following rights: to enter the Licensed Area and do all things necessary or desirable to ascertain the character, extent or value of the petroleum

within that area; to make geological, geophysical, geochemical and topographical examinations; to make borings, sink pits and remove water from old workings; and to remove reasonable quantities of petroleum and other minerals for the purpose of analysis, test, trial or experiment. This licence also gives POGV the right to search for petroleum in any part of the Irish offshore except in any area in which a petroleum exploration licence, reserved area licence or petroleum lease is or may be in force which gives exclusive rights to the holder of that licence, in which case the agreement of the Irish Minister is required for POGV to search in those areas.

POGV is subject to certain restrictions and shall not by virtue of this licence have any right to sell or otherwise dispose of any petroleum found at the Licensed Area.

POGV indemnifies the Irish Minister, Ireland and the State's officers, servants, agent and employees for any claim, demand or damage to person or property arising out of or attributed to the exercise by POGV of the rights granted by this licence or attributed to any act or omission of POGV or its officers, servants, workers or employees.

This licence is also subject to and incorporates the Licensing Terms for Offshore Oil and Gas Exploration, Development & Production 2007, to the extent that they are not modified by the terms of this Licence.

The Petroleum Prospecting Licence was renewed for 12 months with effect from July 1, 2019 and designated PPL 4-19.

At the date of this document the Prospecting Licence remains in full force and effect.

12.3.2 **Licensing Option 16/26 dated 3 June 2016**

This relates to POGV's application for a licensing option over blocks 18/20(p), 18/25(p), 18/30(p), 19/7(p), 19/11(p), 19/12(p) and 19/16(p) under the 2015 Atlantic Margin licensing round terms and conditions.

The letter confirms that the Irish Minister has reserved by way of Licensing Option 16/26 an area of 302.4861 km^2 over blocks 18/24(p), 18/25(p), 18/29(p) and 18/30(p) as set out in further detail on an attached map (the "**16/26 Option Area**") for POGV (50%) and Theseus (50%) from 1 July 2016 to 30 June 2018. They must hold a petroleum prospecting licence for the full period of the Licensing Option.

POGV and Theseus have agreed to carry out a programme of work, including purchasing seismic, well and other technical data relevant to the 16/26 Option Area; performing petrophysical analysis and integrating with existing data; reprocessing a minimum of 300km of 2D seismic data and 400km^2 3D seismic data; mapping leads and prospects; reviewing and assessing the potential of certain structural features within the 16/26 Option Area; incorporating the results into a comprehensive assessment of the petroleum potential of the 16/26 Option Area; and proposing a detailed work programme for any follow-up frontier exploration licence for the approval of the Irish Minister. Such frontier exploration licence would be for a period of 15 years.

POGV and Theseus have agreed to prepare and present reports. This includes reporting to the Department on progress made and preparing and presenting a report before 31 March 2018 which sets out details of the technical assessment of the 16/26

Option Area including the geology of the area; an evaluation of each prospect or lead identified; full documentation of any technical studies or analyses performed or commissioned pertinent to the 16/26 Option Area and a complete listing of the database used.

Annual rental fees will be payable by POGV and Theseus in respect of the 16/26 Option Area. On or before 30 June 2018, POGV and Theseus will either relinquish the Licensing Option or shall have applied to have an exclusive licence of the 16/26 Option Area.

The Licensing Option is also subject to and incorporates the Licensing Terms for Offshore Oil and Gas Exploration, Development & Production 2007.

On 25 May 2018 the Company and its partner Theseus Ltd. submitted an application for a successor authorisation (frontier exploration licence) to the Department of Communications, Climate Action and Environment. The Company's proposed work programme for discussion and negotiation for the initial three-year phase of the FEL included the acquisition and processing of 200 km² of new 3D seismic data; 2D and 3D seismic reprocessing; and desk-top studies.

The Group's Licensing Option 16/26 expired on 30 June 2018. As at the date of this Document the Company is actively continuing its discussions and negotiations with the Department of Communications, Climate Action and Environment regarding the terms of the potential award of a successor authorisation. Further development of this asset is dependent, however, upon the Company demonstrating, either by itself or with the addition of potential farmin partners, a financial and technical operating capability to perform and finance any fully negotiated work programme. No work programme has been committed to for the next 12 months or thereafter and therefore the award of any successor authorisation will be dependent on attracting a farmin partner. In the event this does not occur in a timely manner then the Company may lose its rights to progress to a successor authorisation.

In Ireland the Group is particularly exposed to the issue of CO2 emissions in the context of the fossil fuel industry. The Bill was proposed to limit the scope of the Petroleum and Other Minerals Development Act in respect of the issue of new licences for exploration and extraction of fossil fuels in Ireland. The precise details of the changing government policy with respect to fossil fuel exploration remain to be announced. As a consequence the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and finance necessary to commit to a work programme for any successor authorisation. Under these circumstances Ireland would not be progressed by the Company.

12.3.3 **Licensing Option 16/30 dated 23 November 2016**

This relates to POGV's application for a licensing option over blocks 49/19, 49/20, and part blocks 49/13, 49/14, 49/15, 49/18 and 49/23 in the North Celtic Sea Basin.

The letter confirms that the Irish Minister has reserved by way of Licensing Option 16/30 an area of 799.4 km² over blocks 49/19, 49/20 and part blocks 49/13, 49/14, 49/15, 49/18 and 49/23 as set out in further detail on the attached map (the "**16/30 Option Area**") for POGV and Theseus from 1 December 2016 to 30 November 2018.

They must hold a petroleum prospecting licence for the full period of the Licensing Option.

POGV and Theseus have agreed to carry out a programme of work, including purchasing existing well data; acquiring seismic field tapes, observer's logs and navigation data; reprocessing 600km of 2D seismic data; completing seismic attribute, AVO and rock property analysis; performing 2D gravity modelling on selected 2D seismic lines; analysing specified reservoir areas; analysing seal potential and risk to seal integrity caused by faulting; liaising with a university research department to extend and integrate their studies; mapping the 16/30 Option Area; investigating the potential of an inclined well in two specific locations; quantifying geological risks and chance of success; and incorporating the results into a comprehensive technical report.

Annual rental fees will be payable by POGV and Theseus in respect of the 16/30 Option Area. On or before 31 August 2018, POGV and Theseus will either relinquish the Licensing Option or shall have applied for an exclusive licence of the 16/30 Option Area.

The Licensing Option is also subject to and incorporates the Licensing Terms for Offshore Oil and Gas Exploration, Development & Production 2007.

On 18 October 2018 the Company and its partner Theseus submitted an application to the Department of Communications, Climate Action and Environment for a twelve-month extension to the term of Licensing Option 16/30 to 30 November 2019.The Company's proposed work programme for the twelve-month extension is to complete the initial work programme for Licensing Option 16/30, except for the 600 kms of reprocessing of existing 2D seismic data which would be replaced by the purchase and reprocessing of 12 2D seismic lines from GeoPartners Ltd.. Additional desk-top studies are also proposed to included reservoir engineering and to investigate the feasibility of re-entering and testing the 49/19-1 gas discovery well drilled by Marathon in 1984.

On 22 March 2019, the Company received from the Department of Communications, Climate Action and Environment an extension for a twelve-month period to the term of Licensing Option 16/30 to 30 November 2019 based on its proposed work programme previously submitted and its amendments proposed in its application dated 18 October 2018.

On 31 October 2019 the Company and its partner Theseus submitted an application for a successor authorisation (standard exploration licence) to the Department of Communications, Climate Action and Environment, in the case of Licensing Option 16/30 following a successful application for a 12-month extension to its initial term to 30 November 2019 made on 18 October 2018. The Company's proposed work programme for discussion and negotiation included 1,000 sq. kms. of 3D seismic acquisition and processing and re-entering the original Marathon Oil gas discovery well drilled in 1984/1985 to carry out a production test over the gas-bearing interval that had not been previously tested by Marathon Oil.

The Group's Licensing Option 16/30 expired on 30 November 2019. As at the date of this Document, the Company is continuing its discussions and negotiations with the Department of Communications, Climate Action and Environment regarding

the terms of the potential award of a successor authorisation. Further development of this asset is dependent however upon the Company demonstrating, either by itself or with the addition of potential farmin partners, a financial and technical operating capability to perform and finance any fully negotiated work programme. No work programme has been committed to for the next 12 months and therefore the award of any successor authorisation will be dependent on attracting a farmin partner. In the event this does not occur in a timely manner, then the Company may lose its rights to progress to a successor authorisation.

In Ireland the Group is particularly exposed to the issue of CO2 emissions in the context of the fossil fuel industry. The Bill was proposed to limit the scope of the Petroleum and Other Minerals Development Act in respect of the issue of new licences for exploration and extraction of fossil fuels in Ireland. The precise details of the changing Government policy with respect to fossil fuel exploration remain to be announced. As a consequence the investment climate is very uncertain and there is a significant risk that new regulatory constraints will make it impossible to attract farmin partners and finance necessary to commit to a work programme for any successor authorisation. Under these circumstances, Ireland would not be progressed by the Company.

Further development of the Licensing Options offshore Ireland is dependent upon the Company obtaining successor authorisations, which were applied for on 25 May 2018, in the case of Licensing Option 16/26, and 31 October 2019, in the case of Licensing Option 16/30, the grant of which are conditional on the Company demonstrating, either by itself or with the addition of potential farm-in partners, a financial and technical operating capability to perform its exploration work obligations to be negotiated under the terms of any successor authorisations. No work programme has been committed to for the next 12 months or thereafter and therefore the award of any successor authorisations will be dependent on attracting a farm-in partner to address the financial and technical operating capability and to finalise a work programme with the regulatory authorities which is capable of being financed. In the event this does not occur in a timely manner then the Company may lose its rights to progress to successor authorisations.

12.4 **Registrar agreement**

The Company and the Registrar entered into a registrar's agreement dated 15 January 2018 pursuant to which the Registrar agreed to act as registrar to the Company and to provide transfer services and certain other administrative services to the Company.

The Company has agreed to pay the Registrar's fees within 30 days of receipt by the Company an invoice from the Registrar. The exact fees are dependent on the work carried out by the Registrar, based on a menu of services and associated fees.

12.5 **Administration agreement**

The Company and Consortia Partnership Limited (now called OAK Group (Jersey) Limited) entered into an administration agreement dated 18 May 2018, pursuant to which Consortia Partnership Limited provides administrative services to the Company and its subsidiary undertakings. Consortia Partnership Limited is entitled to a fee of £50,900 per annum, subject to an override if the time expended for the relevant quarter exceeds the quarterly proportion of the annual fee by 20%.

A side letter dated 16 August 2019 amends the terms of the administration agreement to increase the fee entitlement to £65,000 per annum effective from 1 July 2019, charged quarterly in advance to the Company. All other terms conditions within the administration agreement remain in force.

12.6 **Warrant instruments**

A warrant instrument dated 18 May 2018 entered into between the Company and Optiva pursuant to which the Company agreed to issue to Optiva such warrants in the Company, exercisable at the IPO Placing Price for a period of three years from the date of Admission, as are equal in value to the 5% placing commission fee payable by the Company to Optiva under the Optiva Placing Agreement described at paragraph 14.1.1 of this Part XIV.

A warrant instrument dated 18 May 2018 entered into between the Company and Novum pursuant to which the Company s agreed to issue to Novum such warrants in the Company, exercisable at the IPO Placing Price for a period of three years from the date of Admission, as are equal in value to the 5% placing commission fee payable by the Company to Novum under the Novum Placing Agreement described at paragraph 14.1.2 of this Part XIV.

A warrant instrument dated 15 February 2019 entered into between the Company and Arato Global Opportunities LLC ("**Arato**") pursuant to which the Company has agreed to issue to Arato 2,083,333 warrants in the Company at an exercise price of £0.12 for a period of two years from the date of the CLN as described below in paragraph 14.7 of this Part XIV.

A warrant instrument dated 15 February 2019 entered into between the Company and Novum pursuant to which the Company has agreed to issue to Novum 2,000,000 warrants in the Company at an exercise price of £0.12 for a period of two years from the date of the CLN as described below in Paragraph 14.7 of this Part XIV.

12.7 **Convertible loan note instrument (CLN**)

The Company entered into a CLN with Arato Global Opportunities LLC (the **Lender**) on 15 February 2019 in relation to the loan of £1,500,000 (the **Loan Notes**). The nominal amount of each Loan Note is £1 and the aggregate principal amount is £1.5 million. There is no coupon attaching to the Loan Notes and the term is 24 months, after which the Loan Notes are repayable in cash in an amount of 105% of the principal amount plus a fee of 10% of the principal amount being repaid. The Lender has also agreed to make available to the Company a further £250,000 principal of Loan Notes on the same terms, subject to certain conditions, for additional working capital, if required.

The Loan Notes are convertible at the election of the Lender at 105% of the principal amount being converted. The conversion price is calculated as 90% of the volume weighted average share price of a Company's Ordinary Share as shown on the London Stock Exchange for the two trading days immediately preceding the notice of conversion from the Lender. The Loan Notes can otherwise be redeemed at any time by the Company in cash in an amount of 105% of the principal amount plus a fee of 10% of the principal amount being repaid.

In addition, the Lender is being issued with warrants to subscribe for 2,083,333 Ordinary Shares in the Company at an exercise price of 12p per share for a period of 2 years, and Novum, the Company's broker who has arranged the Loan Notes, is being issued with warrants to subscribe for 2,000,000 Ordinary Shares in the Company at an exercise price of 12p per share.

Under the terms of the CLN the Lender is entitled to 25% of any Placing funds to be made available for a cash repayment of the outstanding balance of the loan.

The Company has agreed to issue to the Lender 2,500,000 Ordinary Shares at the Placing Price in consideration for the Lender waiving the requirement pursuant to the CLN that the Company pay to the Lender up to 25 per cent. of the Placing funds in cash. These Ordinary Shares will be issued following Admission, conditional on the Company obtaining new Shareholder approval for such issue, and do not form part of the New Ordinary Shares.

12.8 **WPA with FRAM for profit sharing from FRAM production – IPSC between FRAM and Heritage as varied by supplemental agreements**

On 17 November 2017 POGV, a wholly-owned subsidiary of the Company, and FRAM entered into the WPA relating to the participation by POGV in the drilling of two infill development wells (the "**Work Programme**") in the Innis-Trinity oil field, under the terms of an IPSC between FRAM and Heritage, in return for a share of profits only from the sale of crude oil once the wells are completed and put into production.

The details of the original WPA can be found in paragraph 13.9 of Part XIII of the Company's prospectus dated 21 May 2018, which is available at https://www.predatoroilandgas.com/investors/documents-circulars/. Please refer to the table in Part XII (*Financial Information on the Company and Other Information Incorporated by Reference*) for the relevant cross-reference.

WPA Supplemental Agreement No.1, with an effective date 31 May 2018, assigned the WPA from POGV to POGT, a wholly-owned subsidiary of the Company, and amended the WPA Work Programme to re-focus on a CO2 EOR Pilot Project rather than the originally agreed infill drilling Work Programme.

The terms of the WPA Supplemental Agreement No.1 determined that the CO2 EOR Pilot Project is subject to the following conditions precedent:

(i) FRAM obtaining all necessary permits and authorisations for the CO2 EOR Pilot Project;

(ii) FRAM obtaining the approval of Petrotrin (now called Heritage following a re-structuring of the State oil company) to extend the current expiry date of the IPSC to 31st January 2022 to allow for the incremental rates achieved from the first twelve months of oil production from the CO2 EOR Pilot Project to be fully evaluated before expiry of the current term of the ISPC;

(iii) FRAM to obtain from Heritage a deferral by one year of all its current drilling obligations to allow for the CO2 EOR Pilot Project to be executed and a minimum of 3 months of CO2 to be injected into the Pilot CO2 EOR test site;

(iv) POGT's review and approval of the terms and conditions of the IPSC and all agreements and other requirements affecting the CO2 EOR Pilot Project and unencumbered title to hydrocarbon production from it.

(v) FRAM shall notify POGT within one (1) business day of a change of control of FRAM's holding company Steeldrum and POGT shall then have at its sole discretion the right to withdraw without any penalty within five (5) Business Days from the receipt of the notification from FRAM of the change of control of Steeldrum.

For avoidance of doubt all other commercial terms agreed under the WPA signed on 17 November 2017, including the definition and calculation of profits from the CO2 EOR Pilot Project and the legally-binding exclusive option for POGT to acquire FRAM for an agreed fixed Consideration of US$4.2 million, remain in full force and effect following the signing of the WPA Supplemental Agreement No.1, which has an Effective Date of 31 May 2018. The WPA terms were included in the Predator Oil & Gas Holdings Plc Prospectus dated 21 May 2018, Section 13.9 Well Participation Agreement Page 130 at www.predatoroilandgas.com.

The WPA with FRAM has been further amended by means of Supplemental Agreement No.2, signed on 5 March 2019 with an Effective Date 21 January 2019, whereby the exclusive Option to acquire FRAM has been extended to 31 December 2019 and its exercise by the Company will be subject to a successful CO2 EOR Pilot Project and the conclusions of negotiations between Heritage and FRAM in respect of extending the current term of the IPSC beyond 31 January 2020. A separate option under the WPA signed on 17 November 2017 to acquire Cory Moruga Holdings Ltd., another subsidiary of Steeldrum, was relinquished by POGT.

The WPA with FRAM has been further amended by means of Supplemental Agreement No.3, signed on 31 October 2019 with an Effective Date 26 September 2019, whereby the exclusive Option to acquire FRAM has been extended up to 30 September 2020 and its exercise by the Company will be subject to a successful CO2 EOR Pilot Project, and the conclusions of negotiations between Heritage and FRAM in respect of extending the current term of the IPSC beyond 31 January 2020.

Condition Precedent (iii) above for the CO2 EOR Pilot Project under WPA Supplemental Agreement No.1, namely FRAM to obtain from Heritage a deferral by one year of all its current drilling obligations to allow for the CO2 EOR Pilot Project to be executed and a minimum of 3 months of CO2 to be injected into the Pilot CO2 EOR test site, has been satisfied with the announcement by Columbus on 12 November 2019 of an extension granted by Heritage to the IPSC to 31 December 2021, conditional on CO2 injection occurring on or before 28 January 2020. Heritage also agreed to replace the 7 unfulfilled drilling commitments outstanding in respect of the IPSC work programme with the CO2 EOR Pilot Project. Heritage approval for the pilot CO2 EOR injection was subject to final approval by the MEEI, which was received by FRAM on 3 January 2020.

The sale of Steeldrum, the holding company for FRAM, to Columbus, was announced on 8 October 2018. The WPA and its Supplemental Agreements No.1, No.2 and No.3 between FRAM and POGT remains in full force and effect following the sale of FRAM to Columbus.

FRAM, now a wholly owned subsidiary of Columbus, holds 100% of the rights of the IPSC for Heritage's Inniss-Trinity licence onshore Trinidad.

FRAM currently produces between 120 and 150 bopd from the field, which is sold directly to the state-owned oil company Heritage. FRAM is engaged in operating and drilling infill development/production wells in the field and carrying out workovers for selected wells based on up to 86 wells that have been assigned by Heritage to FRAM under the IPSC.

12.9 Loan Agreement between FRAM and POGT

On 24 July 2019 POGT and FRAM entered into a loan agreement (the "**FRAM Loan Agreement**") whereby POGT is providing an interest-free, unsecured, loan to FRAM to document the operating expenditures, such as provision of a well workover rig for borehole completions for CO2 injection, incurred by FRAM as operator of the IPSC, solely in connection with the Company's CO2 EOR Pilot Project in the AT-4 Block of the Inniss-Trinity field.

The FRAM Loan Agreement records the investment from time to time made by the Company through FRAM in the CO2 EOR Pilot Project. 100% (one hundred percent) of the cumulative investment made through the FRAM Loan Agreement is recovered first from any profits from CO2 EOR enhanced oil production from the AT-4 Block by the Company before net operating profits are split between the Company and FRAM under the WPA.

Currently US$273,800.90 (two hundred and seventy three thousand, eight hundred dollars and ninety cents) has been advanced to FRAM using the FRAM Loan Agreement via addenda dated 10 October 2019, 14 November 2019 and 6 December 2019.

12.11 **Heads of Agreement Take-or-Pay CO2 Gas Supply Contract**

A legally-binding CO2 HOA has been entered into by the Company on 30 July 2018, with an Effective Date of 31 May 2018, with the only in-country CO2 supplier, Massy for a Take-or-Pay CO2 Gas Supply Contract based on a minimum provisional guaranteed daily delivery of 60 Mt CO2.

Under the CO2 HOA there is an Exclusivity Period for the Company to negotiate the C02 Gas Sales Agreement. The Exclusivity Period was initially to 31 August 2018, but has been extended to 30 September 2020 through Take-or-Pay C02 Gas Supply Contract Supplemental Agreements No.1, dated 14 September 2018, No.2, dated 2 January 2019, No.3, dated 4 April 2019, No.4 dated 5 July 2019 and No.5 dated 3 December 2019. Under the same Amendments the start-up for CO2 deliveries has been extended to 31 January 2020 and the Initial 12-month Term for CO2 Sales will now commence on 30 November 2019 or at such later date as the parties may agree, depending on the timing of approval by the MEEI for CO2 injection to commence, which was received on 3 January 2020.

Exclusivity means that up to 30 September 2020 no CO2 Gas Sales Agreement can be entered into by Massy with any other third party. In return for the Exclusivity Period the Company has at its sole expense committed to executing the work required to determining the volumes of C02 and frequency of C02 deliveries required to execute its CO2 EOR Pilot Project and divulging details to Massy of its forecast C02 EOR oil production profiles to facilitate the negotiation and execution of the CO2 Gas Sales Agreement.

12.12 **Arato Global Opportunities Convertible Loan Note** ("**CLN**")

The Company has a CLN for which the outstanding balance is £1.015 million. The CLN, if not converted, is repayable in cash after 24 months to an amount of 105% of the amount outstanding plus a fee of 10% of the principal amount being repaid.

The CLN is convertible at the election of the Lender at 105% of the principal amount being converted at a conversion price calculated at 90% of the volume-weighted average share price of an Ordinary Share as shown on the London Stock Exchange for the two trading days immediately preceding the notice of conversion from the Lender.

In the event the Company undertakes a placing, then the Lender is entitled to a CLN repayment of 25% of the placing proceeds in cash. The Lender has agreed to waive this requirement in the case of the Placing to ensure that the Net Placing Proceeds satisfy the Company's intended current work programme and working capital forecast. In consideration for the Lender waiving this requirement, the Company has agreed to issue to the Lender 2,500,000 Ordinary Shares at the Placing Price. These Ordinary Shares will be issued following Admission, conditional on the Company obtaining new Shareholder approval for such issue, and do not form part of the New Ordinary Shares.

The risk for the Company attached to the CLN is the lack of sufficient existing headroom shares for conversion should the volume-weighted average share price of an Ordinary Share as

shown on the London Stock Exchange for the two trading days immediately preceding the notice of conversion from the Lender be low.

There is also a risk that the CLN will not be able to convert fully into shares before the 24-month Loan Period expires, thereby resulting in a cash repayment by the Company to the Lender.

In the event that the CLN does not convert into shares before the 24-month loan repayment date expires, the Company does not anticipate any difficulties making the outstanding cash repayment to the Lender.

14.13 **Guercif Petroleum Agreement and Association Contract Morocco**

Through its wholly owned subsidiary POGV, the Company holds a 75% working interest in and is the operator of the Guercif Petroleum Agreement and Association Contract. ONHYM, the State oil company, holds 25% and is carried through exploration but funds its pro-rata share of all costs upon a Declaration of Commerciality.

The Guercif Petroleum Agreement and Association Contract I became effective following the issue and gazetting of a Joint Ministerial Order on 4 July 2019 in the Bulletin Officiel No. 6792 1er Kaada 1440.

The Guercif Petroleum Agreement, comprising the Guercif Permits I, II, III and IV, is located in the Guercif Basin and covers 7,269 km².

Oil companies are subject to income tax under Morocco's general tax code at the current rate of 31% per cent. Under Morocco's Hydrocarbon Law, which is referred to in the Guercif Petroleum Agreement, the following two incentives are available to oil and gas companies:

- a 10 year tax holiday from the start of commercial production for each Exploitation Concession; and
- consolidation that allows exploration costs, including dry hole costs, to be deducted against revenues of any Exploitation Concession held by the tax payer.

However, there is a 10-year "holiday" before corporation tax will be charged and any unused tax losses can be offset against the tax due.

POGV is also exempt from withholding tax, import duty and VAT providing it establishes a Moroccan fiscal entity.

No surface rentals are payable for exploration permits. Further, the Guercif Petroleum Agreement provides compensation for POGV in the event of any adverse effect from a change of regulations in Morocco.

The other fiscal terms in Morocco are restricted to a 5% State royalty for gas, applicable after the first 10.6 BCF of net production to the operator from an Exploitation Concession and a 10% State royalty for oil, applicable after the first 300,000 tons of net production to the operator from an Exploitation Concession.

There are no signature bonuses but production bonuses in the form of cash payments exist with a maximum one-off payment of US$5,000,000 on production greater than 30,000 BOE/day. A discovery bonus of US$1,000,000 is also payable on a declaration of a commercial discovery.

Further production bonuses are payable when production reaches certain rates as follows:	Bonus (US$)
10,000 BO/BOE per day	1,000,000
20,000 BO/BOE per day	2,000,000
30,000 BO/BOE per day	3,000,000
Over 30,000 BO/BOE per day	5,000,000

The minimum exploration work programme for the first 30 months of the Initial Period of the Guercif Licence, which commenced on 19th March 2019, is described below:

100% WORK PROGRAMME & BUDGET	US$ MM
250 kms of 2D seismic reprocessing for AVO analysis	150,000
Drilling One Exploration Well (2,000 meters commitment depth)	2,000,000
Guercif Geological Studies – NuTech Petrophysics Palaeogeography, Source Rock Studies, Migration routes	125,000
Moroccan Gas Market Study	40,000
Guercif Licence G & A – US$290,000 p.a. (2.5 years)	725,000
ONHYM Training Budget (2.5 Years)	104,000
CONTINGENCY @ 10%	314,000
Total Excluding US$ 1,500,000 refundable bank guarantee *Exchange Rate 1.28*	3,458,000

The total estimated cost of such minimum exploration work programme is US$3,458,000.

At the end of the first 30 months, POGV may elect to enter into a further period (First Extension Period) of three years, which includes a commitment to drill an exploration well to a minimum depth of 2,000 metres m below ground or to the top of the Middle Jurassic, whichever is penetrated first, and to acquire 200 km2 of 3D seismic data.

12.13 **Rig Option**

On 6 December 2019 PGV entered into a rig option agreement (the "**Rig Option**") with Star Valley Drilling Ltd. ("Star"), a Canadian drilling company currently undertaking an extensive drilling programme for SDX Energy Plc in the Rharb Basin west of the Guercif using its rig no. 101.

The Rig Option is to 31 January 2020, unless otherwise mutually agreed by PGV and Star, to allow for negotiation and execution of a legally binding rig contract, including all commercial terms.

The Rig Option provides for a rig mobilisation date within a window commencing 15 March 2020 and ending 30 April 2020 unless otherwise agreed by mutual consent of PGV and Star.

13 RELATED PARTY TRANSACTIONS

In the period from its incorporation to the date of this Document, the Company has not entered into any related party agreements other than the service agreements and non-executive director appointment letters with the Directors and agreements existing on 24 May 2018.

14 ACCOUNTS AND ANNUAL GENERAL MEETINGS

The Company's annual report and accounts will be made up to 31 December in each year. It is expected that the Company will make public its annual report and accounts within six months of each financial year end (or earlier if possible) and that copies of the annual report and accounts will be sent to Shareholders within six months of each financial year end (or earlier if possible). The Company will prepare its unaudited interim report for each six month period ending 30 June. It is expected that the Company will make public its unaudited interim reports within two months of the end of each interim period.

15 ISSUES OF NEW SHARES

The Directors are authorised to issue up to 100,000,000 Ordinary Shares (with such number being reduced by the 89,000,000 New Ordinary Shares to be issued in the Placing). The pre-emption rights in the Articles have been disapplied, and therefore pre-emption rights do not apply, to up to 97,075,784 Ordinary Shares.

16 GENERAL

16.1 PKF Littlejohn LLP, whose address is 15 Westferry Circus, Canary Wharf, London E14 4HD and which is registered to carry out audit work by the Institute of Chartered Accountants in England and Wales has given and has not withdrawn its consent to the inclusion by reference in this Document of its accountants' report in Part XII (*Financial Information on the Company*) and has authorised the contents of that report for the purposes of complying with Annex 1, Section 1, Item 1.3 of Commission Delegated Regulation (EU) 2019/980.

16.2 SLR whose address is 7 Dundrum Business Park, Windy Arbour, Dublin, D14 N2Y7 has given and not withdrawn its written consent to the issue of each of the four Competent Person's Reports at Part XVIII of this Document and the references herein to its name in the form and context in which they appear.

16.3 The Company has not had any employees since its incorporation and does not own any premises.

16.4 The total expenses incurred (or to be incurred) by the Company in connection with the Placing are £255,000. The estimated Net Placing Proceeds, after deducting fees and expenses in connection with the Placing, are approximately £3,305,000.

17 AVAILABILITY OF THIS DOCUMENT

17.1 Copies of this Document may be collected, free of charge during normal business hours, from the registered office of the Company.

17.2 In addition, this Document will be published in electronic form and be available on the Company's website https://www.predatoroilandgas.com/ subject to certain access restrictions applicable to persons located or resident outside the United Kingdom.

18 DOCUMENTS FOR INSPECTION

18.1 Copies of the following documents may be inspected at the registered office of the Company, 3rd Floor, Standard Bank House, 47-49 La Motte Street, Jersey JE2 4SZ during usual business hours on any day (except Saturdays, Sundays and public holidays) and at the Company's website https://www.predatoroilandgas.com from the date of this Document until Admission:

18.1.1 the Articles of Association of the Company;

18.1.2 the accountants' report by PKF Littlejohn LLP on the historical financial information of the Company for the period ended 31 December 2018 set out in Part XII (*Financial Information on the Company*);

18.1.3 the letters of consent referred to in paragraph 18 of this Part XIV (*Additional Information*); and

18.1.4 this Document.

The date of this Document is 19 February 2020.

PART XV

NOTICES TO INVESTORS

The distribution of this Document may be restricted by law in certain jurisdictions and therefore persons into whose possession this Document comes should inform themselves about and observe any restrictions, including those set out below. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction.

1 GENERAL

No action has been or will be taken in any jurisdiction that would permit a public offering of the Ordinary Shares, or possession or distribution of this Document or any other offering material in any country or jurisdiction where action for that purpose is required. Accordingly, the Ordinary Shares may not be offered or sold, directly or indirectly, and neither this Document nor any other offering material or advertisement in connection with the Ordinary Shares may be distributed or published in or from any country or jurisdiction except under circumstances that will result in compliance with any and all applicable rules and regulations of any such country or jurisdiction. Any failure to comply with these restrictions may constitute a violation of the securities laws of any such jurisdiction. This Document does not constitute an offer to subscribe for any of the Ordinary Shares offered hereby to any person in any jurisdiction to whom it is unlawful to make such offer or solicitation in such jurisdiction.

This Document has been approved by the FCA as a prospectus for the purposes of section 85 of FSMA, and of the Prospectus Regulation. No arrangement has been made with the competent authority in any other EEA State (or any other jurisdiction) for the use of this Document as an approved prospectus in such jurisdiction and accordingly no public offer is to be made in any EEA state (or in any other jurisdiction). Issue or circulation of this Document may be prohibited in countries other than those in relation to which notices are given below.

2 FOR THE ATTENTION OF EUROPEAN ECONOMIC AREA INVESTORS

Pursuant to the Prospectus Regulation, an offer to the public of the Ordinary Shares may only be made once the prospectus has been passported in an EEA Member State of in accordance with the Prospectus Regulation. For any other EEA Member State an offer to the public in that EEA Member State of any Ordinary Shares may only be made at any time under the following exemptions under the Prospectus Regulation, if they have been implemented in that EEA Member State:

a) to any legal entity which is a qualified investor as defined under the Prospectus Regulation;

b) to fewer than 150 natural or legal persons (other than qualified investors as defined in the Prospectus Regulation) in such EEA Member State subject to obtaining prior consent of the Company for any such offer; or

c) in any other circumstances falling within Article 1(4) of the Prospectus Regulation,

provided that no such offer of Ordinary Shares shall result in a requirement for the publication by the Company of a prospectus pursuant to Article 3 of the Prospectus Regulation and each person who initially acquires Ordinary Shares or to whom any offer is made will be deemed to have represented, warranted and agreed with the Company that it is a ‘‘Qualified Investor’’ within the meaning of Article 2(e) of the Prospectus Regulation.

For the purposes of this provision, the expression an "offer to the public" in relation to any offer of Ordinary Shares in any EEA Member State means the communication in any form and by any means of sufficient information on the terms of the offer and any Ordinary Shares to be offered so as to enable an investor to decide to purchase or subscribe for the Ordinary Shares.

This Document may not be used for, or in connection with and does not constitute, any offer of Ordinary Shares or an invitation to purchase or subscribe for any Ordinary Shares in any EEA Member State in which such offer or invitation would be unlawful.

The distribution of this Document in other jurisdictions may be restricted by law and therefore persons into whose possession this Document comes should inform themselves about and observe any such restrictions.

3 FOR THE ATTENTION OF UK INVESTORS

This Document comprises a prospectus relating to the Company prepared in accordance with the Prospectus Regulation Rules and approved by the FCA under section 87A of FSMA. This Document has been filed with the FCA and made available to the public in accordance with Rule 3.2 of the Prospectus Regulation Rules.

In the United Kingdom this Document is for distribution to, and is directed only at, legal entities which are qualified investors as defined under the Prospectus Regulation and are (i) persons having professional experience in matters relating to investments who fall within the definition of investment professionals in Article 19(5) of the Financial Promotions Order; or (ii) high net worth bodies corporate, unincorporated associations and partnerships and trustees of high value trusts as described in Article 49(2) of the Financial Promotions Order; or (iii) persons to whom it may otherwise be lawfully distributed under the Financial Promotions Order, (all such persons together being "**Relevant Persons**"). In the United Kingdom, any investment or investment activity to which this Document relates is only available to and will only be engaged in with Relevant Persons. Persons who are not Relevant Persons should not act or rely on this Document or any of its contents.

Dated: 19 February 2020

PART XVI
DEFINITIONS

The following definitions apply throughout this Document (unless the context requires otherwise):

"**2018 Prospectus**"	the Company's prospectus dated 24 May 2018, published in connection with the IPO;
"**2020 Placing Agreement**"	the placing agreement entered into between the Company, Novum and Optiva dated 14 February 2020;
"**Arato**"	Arato Global Opportunities LLC;
"**Acquisition**"	a Company/Business Acquisition or a Licence/Permit Acquisition, as the context may require;
"**Admission**"	admission of the New Ordinary Shares to the standard listing segment of the Official List and to trading on the main market for listed securities of the London Stock Exchange;
"**Articles**" or "**Articles of Association**"	the articles of association of the Company in force from time to time;
"**Bill**"	the Climate Emergency Measures Bill;
"**Business Day**"	a day (other than a Saturday or Sunday) on which banks are open for business in London and Jersey;
"**certificated**" or "**in certificated form**"	in relation to a share, warrant or other security, a share, warrant or other security, title to which is recorded in the relevant register of the share, warrant or other security concerned as being held in certificated form (that is, not in CREST);
"**Change of Control**"	following a Company/Business Acquisition, the acquisition of Control of the Company by any person or party (or by any group of persons or parties who are acting in concert);
"**City Code**"	The City Code of Takeovers and Mergers (as published by the Takeover Panel);
"**CLN**"	convertible loan note instrument entered into on 15 February 2019;
"**CMH**"	Cory Moruga Holdings Limited;
"**Columbus**"	Columbus Energy Resources plc;
"**Company**"	Predator Oil & Gas Holdings Plc, a company incorporated and registered in Jersey under the

	Companies (Jersey) Law 1991 (as amended) on 19 December 2017, with company number 125419;
"**Company/Business Acquisition**"	the acquisition by the Company or by any subsidiary (which may be in the form of a merger, capital stock exchange, asset acquisition, stock purchase, scheme of arrangement, reorganisation or similar business combination) of an interest in an operating company or business in the oil and/or gas sector as described in Part VII (*The Company's Strategy*) of this Document (and, in such context, references to a company without reference to a business and references to a business without reference to a company shall in both cases be construed to mean both a company or a business);
"**Competent Person's Reports**" or "**CPR**"	the reports by SLR as set out in Part XVI of this Document;
"**Control**"	(i) the power (whether by way of ownership of shares, proxy, contract, agency or otherwise) to: (a) cast, or control the casting of, more than 50 per cent. of the maximum number of votes that might be cast at a general meeting of the Company; or (b) appoint or remove all, or the majority, of the directors or other equivalent officers of the Company; or (c) give directions with respect to the operating and financial policies of the Company with which the directors or other equivalent officers of the Company are obliged to comply; and/or (ii) the holding beneficially of more than 50 per cent, of the issued shares of the Company (excluding any issued shares that carry no right to participate beyond a specified amount in a distribution of either profits or capital), but excluding in the case of each of (i) and (ii) above any such power or holding that arises as a result of the issue of Ordinary Shares by the Company in connection with a Company/Business Acquisition;
"**CO2 HOA**"	Heads of Agreement for CO2 Gas Sales;
"**CREST Regulations**"	The Uncertificated Securities Regulations 2001 (*SI 2001 No. 3755*), as amended and the Companies Uncertificated Securities (Jersey) Order 1999 as amended from time to time, and any applicable rule made under those regulations;
"**CREST**" or " **CREST System**"	the paperless settlement system operated by Euroclear enabling securities to be evidenced

	otherwise than by certificates and transferred otherwise than by written instruments;
"**Directors**", "**Board**" or "**Board of Directors**"	the directors of the Company, whose names appear on page 6, or the board of directors from time to time of the Company, as the context requires, and "**Director**" is to be construed accordingly;
"**Disclosure and Transparency Rules**" or "**DTRs**"	the disclosure and transparency rules of the UK Listing Authority made in accordance with section 73A of FSMA as amended from time to time;
"**Document**" or "**Prospectus**"	this Prospectus;
"**Drilling Contract and Well Services Agreement**"	an industry standard turnkey drilling contract and well services agreement to be entered into between FRAM and WIEG and to be furnished by WIEG on such date that may be mutually agreed between POGV and FRAM;
"**EEA**"	the European Economic Area;
"**EEA Member State**"	member states of the European Economic Area;
"**EEA States**"	the member states of the European Union and the European Economic Area, each an "**EEA State**";
"**EHS**"	environmental, health and safety;
"**Enlarged Share Capital**"	the ordinary share capital of the Company as enlarged by the issue of the New Ordinary Shares;
"**EU**"	the Member States of the European Union;
"**Euroclear**"	Euroclear UK & Ireland Limited;
"**Existing Ordinary Shares**"	the existing 108,172,169 issued ordinary shares of no par value in the capital of the Company;
"**FCA**"	the UK Financial Conduct Authority;
"**Financial Promotions Order**"	the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 (SI 2005/1529);
"**FRAM**"	Fram Exploration (Trinidad) Ltd, a company incorporated in Trinidad & Tobago;
"**FSMA**"	the Financial Services and Markets Act 2000 of the UK, as amended;
"**general meeting**"	a meeting of the Shareholders of the Company or a class of Shareholders of the Company (as the context requires);

"**Gross Proceeds"**	means £3,560,000, being 89,000,000 New Ordinary Shares at the Placing Price;
"**Group**"	the Company and its subsidiaries from time to time;
"**Heritage**"	Heritage Petroleum Trinidad Ltd.;
"**IFRS**"	International Financial Reporting Standards as adopted by the European Union;
"**Investor**"	an investor or prospective investor in the Company;
"**IPO**" or "**2018 IPO**"	the Company's initial admission to trade on the Main Market of the London Stock Exchange, which took place on 24 May 2018;
"IPSC"	the incremental production service contract for Innis-Trinity block dated 1 February 2010 between FRAM and Petrotrin, further details of which are described at paragraph 14.8 of Part XIV of this Document;
"ISIN"	International Securities Identification Number;
"**Irish Minister**"	the minister for communications, climate action and environment in Ireland;
"Jersey Companies Law"	the Companies (Jersey) Law 1991(as amended);
"Jersey Takeover Code"	the Companies (Takeovers and Mergers Panel) (Jersey) Law 2009 and the Companies (Appointment of Takeovers and Mergers Panel) (Jersey) Order 2009;
"LEI"	Legal Entity Identifier;
"**Lender**"	Arato Global Opportunities LLC;
"**Licence/Permit Acquisition**"	the acquisition by the Company or by any subsidiary, or the award to the Company or to any subsidiary, of a licence or permit (which may be on a sole or joint bidder basis) or the conclusion of a farm-in arrangement to any existing licence or permit, in any such case to explore, appraise and/or develop oil and/or gas assets, as described in Part VI (*The Company's Strategy*) of this Document;
"**Licensing Options**"	licensing option 16/26 ("Corrib South") and licensing option 16/30 ("Ram Head"), further

	details of which are given in Part VI (*The Company's Strategy*) of this Document;
"**Corrib South**"	Licensing option 16/26;
"**Ram Head**"	Licensing option 16/30;
"**Listing Rules**"	the listing rules made by the UK Listing Authority under section 73A of FSMA as amended from time to time;
"**Locked-in Parties**"	each of the Directors and their immediate family or related trusts;
"**Lock-in and Orderly Market Agreement**"	the agreement dated 18 May 2018 between the Company, the then directors of the Company and Carl Kindinger, further details of which are contained at paragraph 14.2 of Part XIV of this Document;
"**London Stock Exchange**"	London Stock Exchange plc;
"**MAR**"	Regulation (EU) No 596/2014 of the European Parliament and of the Council of 16 April 2014 on market abuse;
"**Massy**"	Massy Gas Products Trinidad Ltd;
"**MEEI**"	the Trinidad Ministry of Energy and Energy Industries;
"**Memorandum**"	the memorandum of association of the Company in force from time to time;
"**Ministry**"	the Trinidad Ministry of Energy;
"**Moulouya_1 Prospect**"	means the area of the Guercif Licence along the Moulouya river bed which has been identified for drilling based on geological criteria;
"**Net Placing Proceeds**"	the funds received on closing of the Placing less any expenses payable on closing of the Placing in connection with the Placing and Admission which have not already been paid by the Company from its existing cash resources;
"**New Ordinary Shares**"	the 89,000,000 new Ordinary Shares to be allotted and issued by the Company pursuant to the Placing;
"**Non-Executive Directors**"	Dr. Stephen Staley and Carl Kindinger;

"**Novum**"	Novum Securities Limited, placing agent to the Company, and which is authorised and regulated by the FCA;
"**Novum Placing Agreement**"	the conditional agreement dated 18 May 2018 between the Company, the Directors and Novum, a summary of which is set out in paragraph 14.1.2 of Part XIV of this Document;
"**Official List**"	the official list maintained by the UK Listing Authority;
"**Options**"	options for the Directors and Non-Executive Directors to acquire Ordinary Shares in the Company on the Placing;
"**Optiva**"	Optiva Securities Limited, former joint broker and placing agent to the Company, and which is authorised and regulated by the FCA;
"**Optiva Placing Agreement**"	the conditional agreement dated 18 May 2018 between the Company, the Directors and Optiva, a summary of which is set out in paragraph 14.1.1 of Part XIV of this Document;
"**Ordinary Shares**"	no par value shares of the Company including, if the context requires, the New Ordinary Shares;
"**Petrotrin**"	the Trinidadian state-owned national oil company;
"**PGV**"	Predator Gas Ventures Ltd., a company incorporated in Jersey with registered company number 127451 and having its registered office at 3rd Floor, Standard Bank House, 47-49 La Motte Street, St Helier, Jersey JE2 4SZ;
"**Placees**"	those persons who have signed forms of confirmation attached to Placing Letters;
"**Placing**"	the conditional placing of the New Ordinary Shares by Optiva and Novum at the Placing Price pursuant to the 2020 Placing Agreement;
"**Placing Letters**"	the letters from Optiva and Novum (as joint placing agents on behalf of the Company) to Placees inviting irrevocable conditional applications for subscription for New Ordinary Shares;
"**Placing Price**"	4 pence per New Ordinary Share;
"**POGT**"	Predator Oil & Gas Trinidad Ltd, a company incorporated in Jersey with registered company number 125427 and having its registered office at

	3rd Floor, Standard Bank House, 47-49 La Motte Street, St Helier, Jersey JE2 4SZ;
"**POGV**"	Predator Oil and Gas Ventures Limited, a company incorporated in Jersey with registered company number 110127 and having its registered office at 3rd Floor, Standard Bank House, 47-49 La Motte Street, St Helier, Jersey JE2 4SZ;
"**Potential CMH Acquisition**"	the potential acquisition by the Company of the entire issued share capital of CMH;
"**Potential FRAM Acquisition**"	the potential acquisition by the Company of the entire issued share capital of FRAM;
"**Premium Listing**"	a premium listing under Chapter 6 of the Listing Rules;
"**Prospectus Regulation**"	Regulation (EU) 2017/1129;
"**Prospectus Regulation Rules**"	the prospectus regulation rules of the FCA made in accordance with section 73A of FSMA;
"**Registrar**"	Computershare Investor Services (Jersey) Limited or any other registrar appointed by the Company from time to time;
"**Resolution of Directors**"	has the meaning specified in the Articles;
"**Resolution of Members**"	has the meaning specified in the Articles;
"**Reverse Takeover**"	a transaction defined as a 'reverse takeover' under section of Chapter 5 of the Listing Rules;
"**SDRT**"	Stamp Duty and Stamp Duty Reserve Tax;
"**Securities Act**"	the U.S. Securities Act of 1933, as amended;
"**SEDOL**"	Stock Exchange Daily Official List;
"**Share Option Scheme**"	the share option scheme adopted by the Company, further particulars of which are set out in paragraph 6.2 of Part XIV of this Document;
"**share register**"	the register of members of the Company;
"**Shareholder**"	a holder of Ordinary Shares and/or New Ordinary Shares, as the context requires;
"**SLR**"	SLR Consulting (Ireland) Ltd, a company incorporated in Ireland with registered number 253332;
"**Special Resolution of Members**"	has the meaning specified in the Articles;

"**Standard Listing**"	a standard listing under Chapter 14 of the Listing Rules;
"**Steeldrum**"	Steeldrum Oil Company Inc.;
"**Takeover Code**"	the UK City Code on Takeovers and Mergers;
"**TIDM**"	Tradable Instrument Display Mnemonics;
"**Theseus**"	Theseus Limited;
"**TT$**"	Trinidad and Tobago dollars, the lawful currency of Trinidad and Tobago;
"**UK Corporate Governance Code**"	the UK Corporate Governance Code issued by the Financial Reporting Council in the UK from time to time;
"**UK Listing Authority**" or "**UKLA**"	the FCA in its capacity as the competent authority for listing in the UK pursuant to Part VI of FSMA;
"**UK Offshore Funds Regulations**"	the Offshore Funds (Tax) Regulations 2009;
"**uncertificated**" or "**uncertificated form**"	in relation to a share or other security, a share or other security, title to which is recorded in the relevant register of the share or other security concerned as being held in uncertificated form (that is, in CREST) and title to which may be transferred by using CREST;
"**United Kingdom**" or "**UK**"	the United Kingdom of Great Britain and Northern Ireland;
"**United States**" or "**U.S.**"	the United States of America;
"**US$**" or "**USD**"	United States dollars;
"**VAT**"	(i) within the EU, any tax imposed by any Member State in conformity with the Directive of the Council of the European Union on the common system of value added tax (2006/112/EC), and (ii) outside the EU, any tax corresponding to, or substantially similar to, the common system of value added tax referred to in paragraph (i) of this definition;
"**Warrant**"	a warrant to subscribe for an Ordinary Share;
"**Well Participation Agreement**" or **"WPA**"	the well participation agreement between POGV and FRAM dated 17 November 2017 whereby POGV shall fund the cost of two infill development wells. Further details of which can be found in Part XIV of this Document;

"**WIEG**"	West Indian Energy Group Ltd., an operating services company;
"**WIEH**"	West Indian Energy Holding;
"**16/26 Option Area**"	the area of 302.4861 km^2 reserved by the Minister by way of licensing option 16/26 over blocks 18/24(p), 18/25(p), 18/29(p) and 18/30(p) as set out in further detail on the map in Part VIII of this Document;
"**16/30 Option Area**"	the area of 799.4 km^2 reserved by the Minister over blocks 49/19, 49/20 and part blocks 49/13, 49/14, 49/15, 49/18 and 49/23 as set out in further detail on the map in Part VIII of this Document;
"**2010 PD Amending Directive**"	directive 2010/73/EU; and
"**GBP**" or "**£**"	pounds sterling, the lawful currency of the UK.

References to a "**company**" in this Document shall be construed so as to include any company, corporation or other body corporate, wherever and however incorporated or established.

PART XVII
GLOSSARY

"**API**"	American Petroleum Institute
"**appraisal**"	activity carried out after a discovery has been made to determine the size of an oil or gas accumulation
"**AVO**"	amplitude variation with offset
"**barrel**"	a unit of volume measurement used for petroleum and its products
"**BCF**"	billion cubic feet
"**BOE**"	barrels of oil equivalent
"**bopd**"	barrels of oil per day
"**carry, carried**"	the arrangement whereby the costs of one party are paid by another party
"**cfgpd**"	cubic feet of gas per day
"**CO2 EOR**"	Enhanced Oil Recovery through CO2 gas injection
"**E&P**"	exploration and production
"**Enhanced Oil Recovery**" or "**EOR**"	the implementation of various techniques for increasing the amount of crude oil that can be extracted from an oil field
"**farm-in" or "farm-out**"	the arrangement by which one party (the farm-in partner) acquires an interest in a concession by paying all or part of the financial commitment of another party, thus carrying the costs of the farm-out partner
"**Hydrocarbon Code**	the hydrocarbon code of the Kingdom of Morocco, composed of law n°21-90 relating to research and exploitation of hydrocarbon deposits and decree n°2-93-786 for the application of the law n°21-90
"**km**"	kilometres
"**km²**"	square kilometres
"**m**"	metres
"**NBP**"	UK national balancing point
"**Guercif Petroleum Agreement**"	the petroleum agreement between ONHYM and PGV relating to the Guercif Licence;
"Guercif Association Contract"	the Association Contract between ONHYM and PGV relating to the Guercif Licence

"Guercif Permit Agreement"	one of four Permits covered by the Guercif Petroleum
"Guercif Licence"	as defined on page 37 of this Document
"Joint Ministerial Order"	the Ministerial Order approved jointly by the Minister of Energy and the Minister of Finance relating to the Guercif Petroleum Agreement and Association Contract regarding the exploration and exploitation of hydrocarbons in the area of interest named Guercif, made between ONHYM and PGV
	the area which is the subject of the Guercif Licence
"**MW**"	megawatt
"**MV**"	market value
"**ONAREP**"	the previous name of the government organisation in Morocco responsible for both mining and petroleum activities – now ONHYM
"**ONHYM**"	Office National des Hydrocarbures et des Mines
"**psi**"	pounds per square inch
"**Rharb**"	a geological basin located on the Atlantic coast of Morocco that is analogous to the Guercif basin in its development and sedimentary fill. Also known as the Gharb basin
"**reservoir**"	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids, which is a critical component of a complete petroleum system
"**seismic reprocessing**"	reworking previously acquired reflection seismic data, using the latest technology, to attempt to improve resolution
"**TCF**"	trillion cubic feet
"**2D seismic data**"	reflection seismic data or a group of seismic lines acquired individually such that there are typically significant gaps (commonly one km or more) between adjacent lines. A 2D seismic survey contains sufficient information to permit mapping of the geological structure of the subsurface
"**3D seismic data**"	reflection seismic data or a group of seismic lines acquired such that the spacing between the lines are typically 100m. A 3D seismic survey contains closely spaced information sufficient to permit three dimensional mapping of the geological structure of the subsurface

PART XVIII

REGULATORY ENVIRONMENT

Key regulatory authorities and regulatory considerations

TRINIDAD

Heritage Petroleum Trinidad Ltd. ("Heritage")

Holder of Inniss-Trinity Exploration and Production (Public Petroleum Rights) Licence.

Heritage are required to approve the CO2 EOR work programme in terms of technical justification, HSE compliance and fulfilment of the Incremental Production Service Contract ("**IPSC**") work commitment agreed between Heritage and FRAM Exploration Trinidad Ltd. ("**FRAM**"), the operator of the IPSC.

Ministry of Energy and Energy Industries ("MEEI")

MEEI are the regulatory authority responsible for overseeing and regulating all oil and gas operations in Trinidad.

MEEI are required to approve the CO2 EOR work programme in terms of technical justification, HSE compliance and economic viability.

Environmental Management Authority ("EMA")

EMA are the regulatory authority responsible for overseeing and monitoring environmental compliance.

EMA are required to approve the CO2 EOR work programme health, safety and environmental compliance by issuing a Certificate of Environmental Clearance ("**CEC**").

MOROCCO

Office National des Hydrocarbures et des Mines ("ONHYM")

ONHYM are the State Oil company and joint venture partner in the Guercif Petroleum Agreement ("**Guercif PA**") and are also the regulatory authority responsible for regulating all oil and gas operations in Morocco and executing oil and gas Petroleum Agreements.

ONHYM are required to approve the operator of the Guercif PA, PGVL, work programmes and annual budgets.

Ministere de l'Energie, des Mines et de l'Environnement, Departement de l'Environnement ("MEME")

MEME are the Ministry responsible for regulating and monitoring the environmental impact of drilling and seismic operations in Morocco.

MEME are required to approve the Environmental Impact Assessment for the Guercif drilling programme.

Ministry of Energy and Mines ("MMEM") and Moroccan Minister of Finance ("MMF")

The MMEM and MMF are required to issue a Joint Ministerial Order to ratify the signing of a Petroleum Agreement between ONHYM and its joint venture partners.

IRELAND

Department of Communications, Climate Action and Environment ("DCCAE") Petroleum Affairs Division ("PAD")

The DCCAE are the regulatory authority responsible for overseeing and regulating all oil and gas operations in Ireland, including the issuing of licences and successor authorisations based on the recommendations of the PAD.

As part of the process of evaluating the suitability of a company for a successor authorisation, an Exploration Licence or a Frontier Exploration Licence, the financial capability of the company is taken into consideration to determine a company's ability to execute a more substantive and costly work programme normally associated with such successor authorisation.

PAD is also responsible for commissioning Strategic Environmental Assessments ("SEA") in accordance with EU Directive 2001/42/EC required to assess the potential impact on the environment of for example seismic and drilling operations.

PART XIX
COMPETENT PERSON'S REPORTS

The Company is required by paragraphs 131 to 133 of the ESMA update of the CESR recommendations to include an independent mineral expert's report in this Document. The Company commissioned SLR to prepare the independent expert's reports (referred to as the Competent Person's Reports) as follows:

- Trinidad;
- Morocco;
- Corrib South (Ireland); and
- Ram Head (Ireland),

which are set out in full below.

COMPETENT PERSONS REPORT

PREDATOR OIL AND GAS TRINIDAD LTD

OR

PREDATOR OIL AND GAS HOLDINGS PLC

ONSHORE TRINIDAD

SLR Ref: 501.00269.00003
Final
30 January 2020

BASIS OF REPORT

This document may contain information of a specialised and/or highly technical nature and the Client is advised to seek clarification on any elements which may be unclear to it.

Information, advice, recommendations and opinions in this document should only be relied upon in the context of the whole document and any documents referenced explicitly herein and should then only be used within the context of the appointment.

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1.0 Introduction

SLR Consulting (Ireland) Ltd ('SLR') of 7 Dundrum Business Park, Windy Arbour, Dublin 14, Ireland, has been commissioned by Predator Oil and Gas Trinidad Ltd (POGT) or Predator Oil and Gas PLC (the "Company" or "Predator") to complete a Competent Person's Report (the "CPR") on the company's Well Participation Agreement (WPA), as amended on 30th July 2018, effective date May 2018 under which the WPA was assigned to Predator Oil and Gas Trinidad Ltd and the option to acquire FRAM Exploration (Trinidad) Ltd was extended to 31st December 2019. The WPA was amended to focus on CO_2 EOR operations with the work programme amended whereby POGT would plan, prepare and execute a Pilot CO_2 EOR Project with FRAM Exploration Trinidad Limited who is operator of the Incremental Production Service Contract for the onshore Innis Trinity Block that contains the Inniss Trinity producing oil field.

This CPR has been prepared in accordance with the requirements of paragraphs 131 to 133 of the ESMA update of the CESR recommendations in respect of the consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive to include an independent expert's report (CPR) in a prospectus document. Resources are reported in accordance with The Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (SPE, AAPG, WPC, SPEE, SEG, SPWLA, EAGE, 2018). The deterministic incremental approach was chosen because the Innis Trinity Block CO_2 EOR project has a pilot development plan but the full range of reliable values for input parameters to a probabilistic approach are not available. Incremental CO_2 Enhanced Oil Recovery associated with analogous reservoirs provides insight and comparative data to assist in the estimation of recoverable resources.

The CPR has been prepared by Mr Nick O'Neill, with assistance from Mr Richard Vernon and Mr Lloyd Vaz based on data supplied by the Company, a literature search carried out by SLR and some independent verification. The data comprised details of permits and acreage interests, basic exploration geological and geophysical data, petroleum engineering data, interpreted data, and technical presentations. SLR has exercised due diligence and independent analysis where appropriate on all technical information supplied by the Company. SLR has not independently checked title interests with Government or licence authorities. No site visit was made to the Inniss Trinity Field.

Richard Vernon has more than 30 years' experience in the energy sector. After graduating with a business degree majoring in accounting and marketing, he worked as a financial analyst specialising in the Canadian oil and gas sector. He then joined the London based consultancy Petroleum Economics Limited and covered all aspects of the international oil and gas industry, including exploration/production and refining/marketing, taxation and licensing regimes, supply/demand/price strategies and forecasting, etc. for a wide range of clients including governments, international institutions and national and private oil companies. Subsequently, he moved to the US based multinational oil and gas company Phillips Petroleum Company as Director of External Affairs, responsible to the Managing Director of the Europe/Africa Division.

Nick O'Neill BSc MSc PGeo EurGeol MEI PESGB M AAPG is a Senior Petroleum Geologist and Director of SLR Ireland. Mr O'Neill joined SLR in 1994, having worked internationally in oil exploration operations since 1977. He was operations manager in the Middle East for an oilfield service company. He obtained an MSc in Petroleum Geology in 1986. He was operations geologist with BP and Shell in London and Aberdeen responsible for North Sea exploration operations. He has written a number of valuations and CPR reports on hydrocarbon properties in Ireland, the US, West Africa, and Italy for UK and Irish based independent oil companies.

Lloyd Vaz BSc MSc. Petroleum Geoscience is experienced in seismic interpretation, geological and geophysical modelling, petrophysics and wireline analysis. He is familiar with all technical stages of hydrocarbon exploration. He joined SLR in 2018 as a project geologist. He completed his M.Sc. in Petroleum Geoscience at University College Dublin in 2017 and after a short period working with Tullow Oil and the Irish Centre for Research in Applied Geosciences in Dublin he joined SLR to work as project co-ordinator for the Irish Petroleum Infrastructure Programme.

SLR Consulting (Ireland) Ltd. has many years of experience undertaking independent expert studies and has completed Expert Reports and Valuations for listings on the London, Copenhagen, Dublin, Vancouver, Luxembourg and Australian Stock Exchanges.

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

INDEPENDENCE OF SLR

This competent persons' report has been prepared by Nick O'Neill who is professionally qualified and a member in good standing of the Institute of Geologists of Ireland, an institution relevant to the activity being undertaken, and who is subject to the enforceable rules of conduct. Nick has at least five years' relevant professional experience in the estimation, assessment and evaluation of oil and gas projects. Nick is independent of Predator Gas Ventures Ltd, its directors, senior management and its other advisers; has no economic or beneficial interest (present or contingent) in the company or in any of the oil and gas assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

SLR confirms that, based on the information provided to it and to the best of its knowledge, no material changes have occurred since the date of the competent person's report the omission of which would make the competent person's report misleading. The assessment of infrastructure is based on information provided by independent drilling consultant Dennis Krahn following his site visit between14th and 22nd April 2019.

We confirm that SLR is responsible for this letter and the contents of the CPR and we declare that we have taken all reasonable care to ensure that the information contained in this letter and the CPR is in accordance with the facts and there is no omission likely to affect its import.

Yours faithfully,

Mr. Nick O'Neill

Director

SLR Consulting (Ireland) Ltd.

2.0 Legal Overview

Predator Oil and Gas Trinidad Ltd (Predator) has negotiated an agreement with FRAM Exploration (Trinidad) Ltd (FRAM) whereby Predator will fund and help plan a CO_2 Enhanced Oil Recovery Pilot Project in the Inniss-Trinity Field, which is operated by FRAM. FRAM is a fully owned subsidiary of Columbus Energy Resources PLC (Columbus). As part of Predator's agreement with Columbus, Predator has the right to purchase FRAM through a Share Purchase Agreement (SPA) on or before 31st December 2019 for US$4.2m if the CO_2 pilot project is a success.

FRAM own one hundred percent (100%) of the operating rights interest in the Inniss-Trinity Incremental Production Sharing Contract (IPSC) with Heritage Petroleum Company Limited (previously Petrotrin) (Heritage). The IPSC was issued to FRAM on 1st February 2010 and runs for 10 years to 31st January 2020. Predator has indicated that it should be possible to extend the duration of the IPSC by negotiation with Heritage. The IPSC contains annual Minimum Work Obligations, mainly in the form of development wells. The IPSC gives FRAM exclusive rights to all petroleum it develops and produces from its activities on the Block but requires FRAM to sell all of its production to Heritage. Heritage pays FRAM a Service Fee based on the market value of the petroleum delivered less a number of deductions (Royalties, Notional Overriding Royalty, Facilitation Fee, Licence Fee etc). These are specified in the original IPSC. The restructuring of Petrotrin's operations in October 2018 included the shutdown of the Point-a-Pierre refinery operations. This is unlikely to impact on crude sales arrangements. The first cargo of local crude was successfully exported in November 2018.

Predator signed an amendment of the Well Participation Agreement (WPA) with FRAM on 21st January 2019 whereby Predator shall fund 100% of a Pilot Enhanced Oil Recovery Project in the Inniss Trinity Block using injected carbon dioxide (Pilot CO_2 EOR). Under the amended WPA FRAM will obtain from Heritage a deferral by one year of all its current drilling obligations to allow for the Pilot CO_2 EOR and shall subcontract the West Indian Energy Group Operating Service Company (WIEG) and/or other suitably qualified service providers for operations and well services for the Pilot CO_2 EOR. On 27th February 2019 Heritage approved the conduct of the Pilot CO_2 EOR subject to FRAM obtaining all necessary approvals from the Environmental Management Authority ("EMA") and the Ministry of Energy and Energy Industries. If the Pilot CO_2 EOR is successful FRAM will pay Predator 100% of the Market Value (less costs and deductions) of any crude oil produced until full cost recovery, following which net proceeds will be split 50/50. This WPA is separate from the SPA and is not conditional on its final agreement.

Predator believes the application of $C0_2$ EOR in an area of the Inniss-Trinity Field that has not been subject to secondary recovery through waterflood and to reservoirs that may not be highly responsive to waterflood, potentially offers a better opportunity to significantly increase production from the field than infill drilling. The AT-4 Block is a good candidate for EOR because an intended waterflood programme was never implemented. The pilot project would involve trucking CO_2 from an industrial plant some 40 kms distant and injecting it into the field for EOR. On 31st August 2018 Predator signed the Heads of Terms Agreement for a take or pay CO2 Gas Supply Contract with Massy Gas Products (Trinidad) Ltd. This pilot project is intended to prove up the concept of a more widespread CO_2 EOR programme in the area. By way of Supplemental Agreements dated 14th September 2018, 2nd January 2019, 4th April 2019 and 5th July 2019, the Exclusivity Period for Predator to negotiate a Gas Sales Agreement has been extended to 30th April 2020 to allow for planning of the CO_2 EOR Project to be completed and injection volumes to be quantified.

3.0 Geological Overview

3.1 Onshore Trinidad

The Island of Trinidad lies north of the Orinoco River's mouth in the eastern Venezuelan Basin (Figure 1). Trinidad's geology is complex and often referred to as a geologist's nightmare. A seven stage evolutionary model for the Trinidad area best fits the geological data (Persad & Ritson, 2014).

1) Pre-Rift, Syn-Rift and Drift (Late Jurassic-Mid Cretaceous)

This first phase comprises pull apart and sea floor spreading, accompanied by thick suites of sediments, in response to crustal attenuation and cooling. Prior to that North America was welded to South America, with the Yucatan Block in between. The proto-Caribbean Seaway had previously opened with the probable initial rotation of the Yucatan Block away from South America about a pole around the northwestern tip of South America.

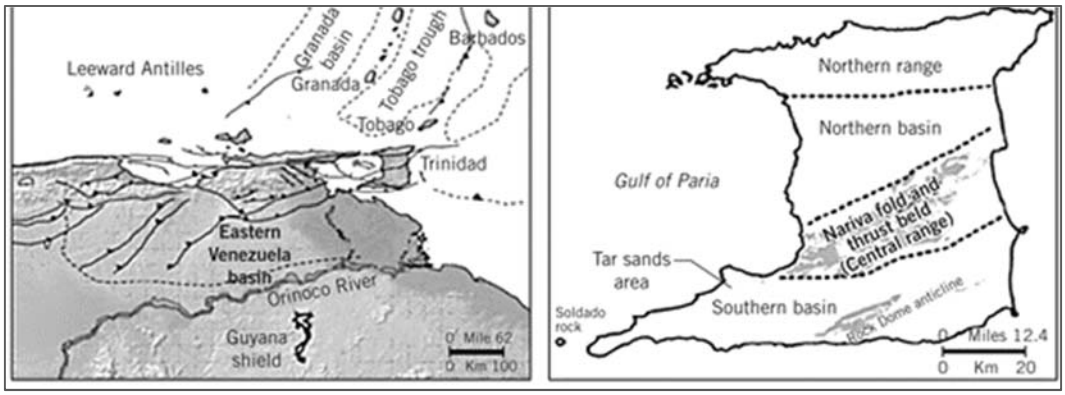

Figure 1 Trinidad Regional setting & geological provinces (Source: Hosein et al)

As the Yucatan Block pulled further away extensional tectonics similar to that occurring in the typical syn-rift stage predominated, and evaporite deposition occurred in the proto-Caroni Basin, and extended westward into eastern Venezuela, into an area known as the Espino Graben. This graben is now recognized to be as old as Cambrian in age, and to extend as far west as the Colombian border. Within the graben Upper Jurassic basaltic volcanics dated at 162 million years have been found, together with red-beds. The extensive evaporites could be the mobile rocks on which the older thrust sheets of the fold-thrust belt slid, at least in the Trinidad area. Northwest of the graben the proto-Araya Northern Range (ANR) Terrane was left behind as the Yucatan block moved away. The carbonate platform sitting on the leading edge of the proto-Araya-Northern Range Terrane moved southeast in later collisions associated with the westward translation of South America relative to the Caribbean Plate.

Continuing separation between the Americas occurred within the proto-Caribbean seaway with the initiation of a southwest trending spreading centre between South America and Yucatan. Thick turbidites most likely represent lowstand basin floor and slope fans formed during falling sea level or lowstands of Lower Cretaceous times.

2) Passive Margin (Mid-Late Cretaceous)

Northern South America remained a passive margin, with a stable platform and uninterrupted sedimentation into the Palaeocene in the west and Eocene in the east. The anoxic shales of the Gautier

and Naparima Hill formations of Upper Cretaceous age were formed during one of the highest stands of sea levels in Earth's history, seemingly accompanied by significant upwelling.

3) North-South Compression (Late Cretaceous-Eocene)

As the proto-Caribbean continued drifting to the north, a spreading centre was seemingly initiated. By latest Cretaceous, compression-induced subduction seems to have started on the flanks of the passive margin.

4) Return to Passive Margin (Eocene-Oligocene)

Oblique convergence between the Caribbean Plate and northern South America started in the west in the Palaeocene; it did not reach the Trinidad area until Late Oligocene. During this period (i.e. prior to Late Oligocene) the Trinidad area seems to have been dominated by a return to passive margin conditions, with main sedimentary input still coming from the Guyana Shield area to the south and southwest.

5) Sequential Oblique Collision (Late Oligocene-Mid Miocene)

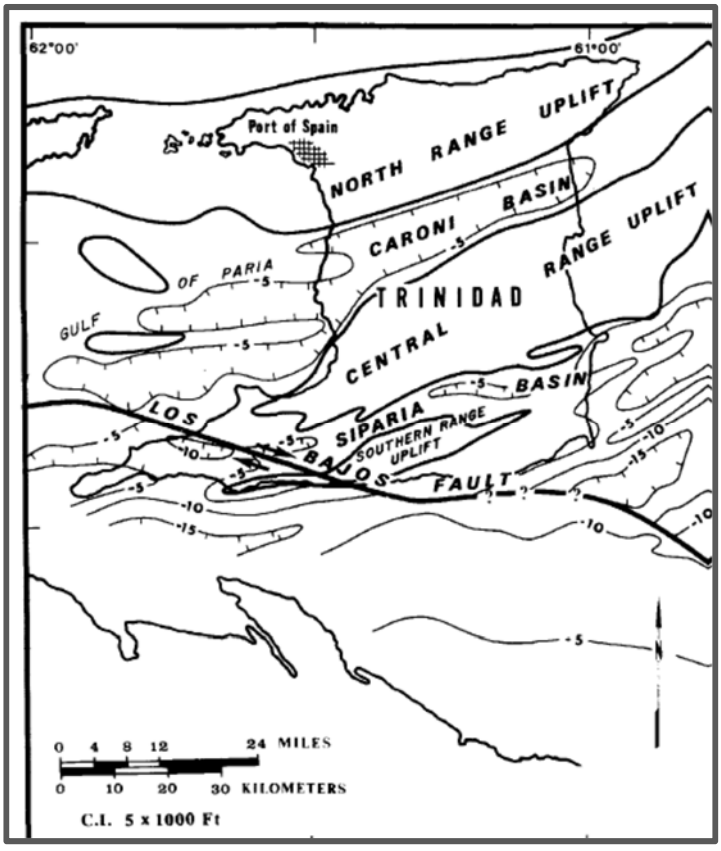

Figure 2 Structural Map (Source: Michelson, 1976)

The diachronous oblique collision of the migrating Caribbean Plate with the northwest extremity of northern South America started in the Palaeocene and continued throughout the rest of the Tertiary moving eastwards with time. The impact of this sequential oblique collision in the Trinidad area was overthrusting of the metamorphic Northern Range Terrane onto the proto-Caroni Basin; development of a series of highly asymmetric anticlines formed within the overthrust east-northeast to west-southwest trending Oligo-Miocene detached fold-thrust belt; downward loading of the crust south-southeast of the active old thrust belt; and development of a thick sequence of turbidite sediments in the fore-deep basin, trending east-northeast to west-southwest, just in front of the leading edge of the fold-thrust belt. This overthrusting was the start of deep burial of Upper Cretaceous source rocks with pene-contemporaneous maturation and expulsion. As the collision progressed in an east-southeast direction a series of source kitchens were formed, with each kitchen delivering a phase of maturation and expulsion. The vast majority of all oils onshore Trinidad are sourced by the Upper Cretaceous Naparima Hill and Gautier formations.

6) Wrench Phase (Late Miocene-Recent)

In Late Miocene times (around 13 ma) the Gulf of Paria pull-apart Basin was formed as the right lateral movement of the El Pilar in eastern Venezuela stepped over via an oblique wrench on the eastern coast of Venezuela to the Warm Springs Fault and to the Central Range Fault. Along the Central Range Fault transpression resulted in the uplift of the Central Range and the formation of a series of faults, such as the Los Bajos Fault, termed lateral ramps. The overthrust portions join together and coalesce along the southern margin as the Southern Range Uplift or Anticline (Figure 2).

7) Continental Embankment (Deltaic Phase) (Pliocene-Present)

When the Caribbean Plate reached the eastern end of northern South America, the main part of the delta pushed eastward into the open Atlantic. Eastward progradation resulted in the migration of the deltaic depocentres, of which four are recognized, two in the Pliocene, and two in the Pleistocene.

In southern Trinidad the Miocene turbidite sandstones and heterolithics represent slope deposits such as turbidite channel fill, channel levees and mudstones (Figure 3). The sands are moderate to well sorted, very fine to fine grained, occasionally mud rich heterolithic to more massive non-laminated sandstone interbedded with bioturbated mudstones. The Inniss Trinity Field is interpreted to be in a proximal position on the slope with a series of narrow channels within a levee complex on a mud dominated slope (Siggerud, 2014).

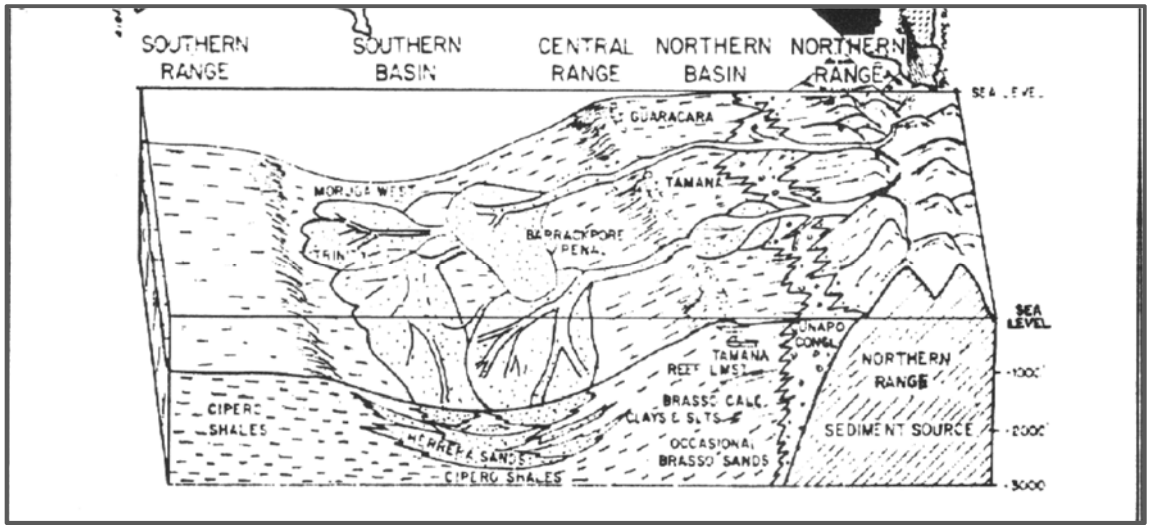

Figure 3 Miocene Sand Facies Relationships

3.2 Petroleum System

Most of the four billion barrels of oil extracted from onshore and offshore Trinidad in the last 100 years has come from the youngest, mainly Plio-Pleistocene, sediments. Onshore Miocene turbidite sands, including the Herrera sands, are significant producers of oil. The tectonic activities within the Miocene and Pliocene created a series of faulted anticlines, which form the main structural framework for oil accumulation from Cretaceous source rocks such as the Gautier and Naparima Hill formations (Figure 4).

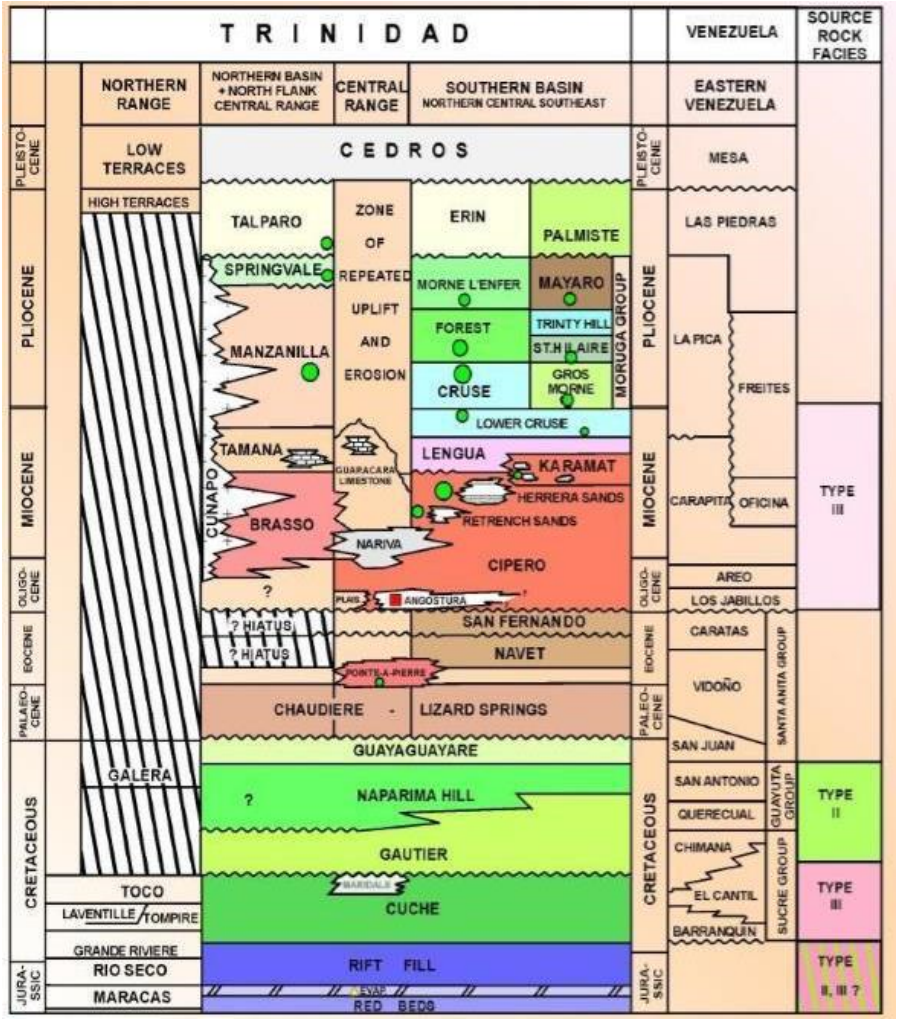

Figure 4 Stratigraphic Chart Trinidad (Source: Geological Society of Trinidad and Tobago)

The northeast-southwest thrust faults and northwest-southeast trending normal faults act as flow barriers forming separate hydrocarbon accumulations with different formation pressures and oil water contacts. Lenticular sand bodies are prominent in the Miocene deltaic setting and the right lateral wrench slip Los Bajos Fault provides vertical migration pathways for oil and gas. The Miocene turbidite sands are found in the Naparima Nariva Fold and Thrust Belt which underlies the piggyback Southern Basin south of the Central Range Uplift and north of the Southern Range Anticline (Figure 2).

The Inniss Trinity Field is located in the Southern Basin and produces from the Miocene Herrera Sands at depth of between 500 ft and 6,000 ft.

3.3 Exploration History and Database

While Trinidad was known to its Spanish conquerors in the 1500s for its pitch the first oil wells were drilled by the Trinidad Petroleum Company in 1857 near the La Brea pitch lake. In the early 1900s the Oil Exploration Syndicate of Canada drilled a well at Guayaguayare which produced oil at 300 barrels a day. Further substantial discoveries were made between 1907 and 1910 near La Brea, at Port Fortin and elsewhere. In 1914 the Forest Reserve Field was found; in 1911 to 1918 Barrakpore; in 1936 Penal and Wilson and in 1950 Cats Hill. The acreage that includes the Innis Trinity Field was originally leased to two companies, United British Oilfields Trinidad (part of Royal Dutch Shell) who became operators of the Inniss Field and Antilles Petroleum Company who operated the Trinity Field (Figure 5).

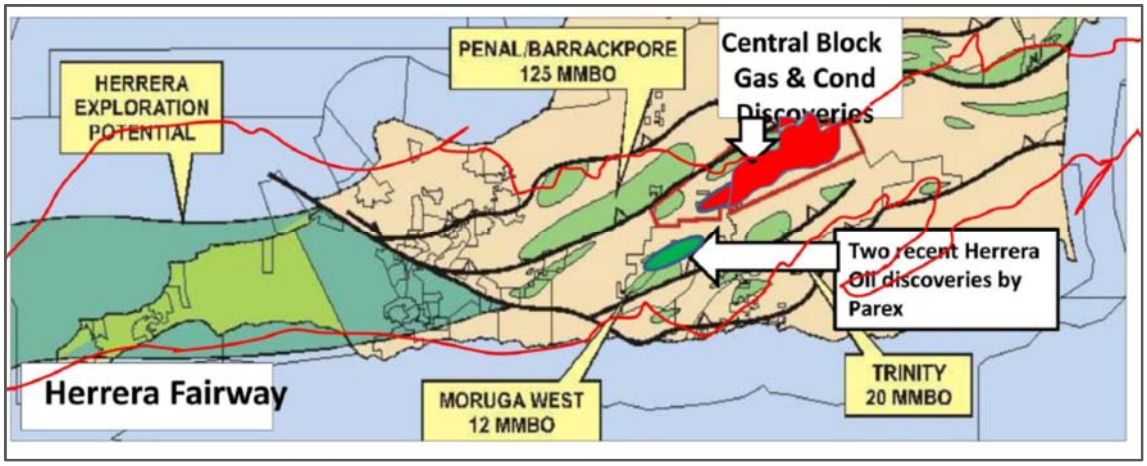

Figure 5 Commercial discoveries in the Fold and Thrust Belt sediments of the Southern Basin (Source: Persad & Ritson 2014)

Development of the Trinity Field began in 1956 with the drilling of AT-1 which was abandoned. Two follow up wells AT-2 and AT-2X were also unsuccessful. Commercial production was achieved by Shell Trinidad with AT-3, which encountered oil bearing Herrera sands between 780ft and 968ft in January 1957. Texaco Trinidad Inc became operator of the Trinity Field in 1958. In 1965 the Trinity Field had 90 wells drilled and an annual production of 1.04 million barrels. The cumulative production to end December 1965 was 8.44 million barrels. Texaco was operator of Trinity Field in 1979 with 95 wells drilled, annual production at 194,706 barrels and cumulative production at 14.20 million barrels. (Deal, 1981). In March 1985 the government of Trinidad and Tobago acquired the assets of Texaco Trinidad Inc. and the Trinity Field was then operated by Trintoc (Wiman, 1986).

In 1965 The Inniss Field was operated by Shell Trinidad with 33 wells drilled and an annual production in excess of 220,000 barrels. The cumulative production at end December 1965 was 4.527 million barrels (Sass & Neff, 1966). Trinidad and Tobago Oil Company (Trintoc) became operator of the Inniss Field in 1974. In 1979 Innis Field had 38 wells drilled, annual production at 46,842 barrels and cumulative production at 5.843 million barrels. In 1965 the combined production from the Innis Trinity Fields was over 3,500 bopd (Sass & Neff, 1966). Secondary recovery waterflooding was implemented in the Trinity Field in 1973 because oil production had declined to approximately 550 bopd. In 1974 onshore production declined in spite of continued efforts in development drilling and secondary recovery techniques. The decline was exacerbated by a number of factors including stagnation in field operations, erratic supply of electricity to pumping wells, sand problems and labour disputes. No enhanced recovery

has been attempted in the Inniss Field where excessive water production has been a problem (Acham, 2013).

The year 1986 saw a significant decrease in exploration activity. Seismic activity was down 77% and exploratory drilling down 47%. Development drilling decreased 22%. In 1986 development drilling was down 18% with Trintoc and Trintopec, both state oil companies, accounting for all but one of the onshore wells.

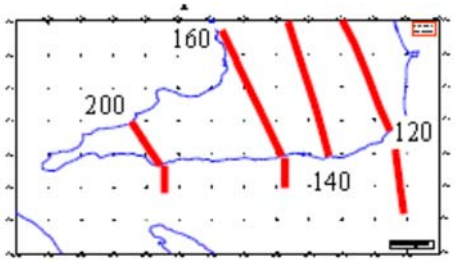

Figure 6 Location map of seismic lines

In 1989 a 2920km^2 deep drilling right permit was awarded to the Southern Basin Consortium of Exxon (operator), Chevron and Total with the state oil companies Trintoc and Trintopec carried. The permit allowed the consortium to explore for oil between 8,000 ft and 17,000 ft. Over 7,000 kms of onshore seismic was acquired in 1989 and 1991.

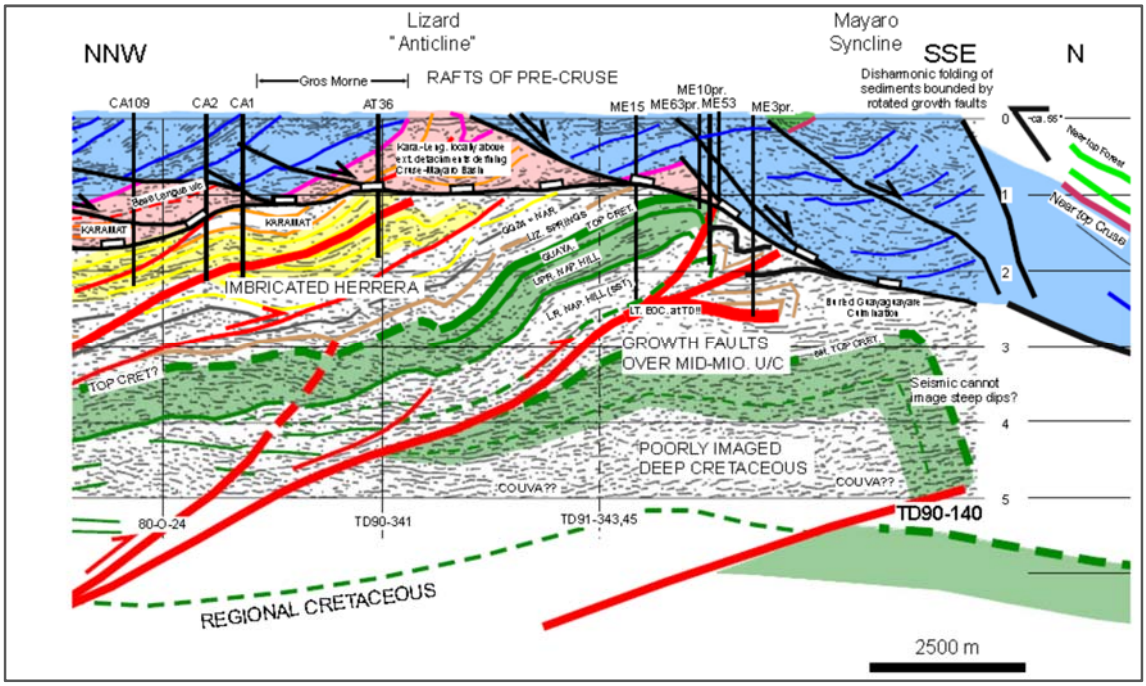

Figure 7 Part of seismic line TD90-140 showing well AT36 in the Trinity Oil Field intersecting imbricated Herrera sands (Source: Pindell & Kennan 2007)

There is an extensive database of technical reports from previous operators, digital wireline logs in LAS, Excel and pdf formats for up to 100 wells, current monthly production data for 26 wells, well files and 2D seismic data. Interpretation of the 1991 vintage 2D seismic data indicates several major thrust faults that intersect the wells but are not recognised in the well bore due to lack of biostratigraphic control. The thrusts are confirmed by wireline log characteristics and contour misties. The Trinity Inniss Field is highly compartmentalised by three main regional thrust faults which dip to the northwest and normal faults generally downthrown to the northeast (Figure 7).

3.4 Inniss Trinity Field Development

Peak production of about 4,200 bopd was achieved by 1958 with most of the production from the Trinity Field. Two secondary recovery waterflooding programs were performed on the Trinity Field in the 1970s and 1980s with moderate success (Persad, 2015). Due to structural complexity and varying reservoir quality across the field more localised waterflooding in certain fault blocks was recommended to improve waterflood performance. Texaco recorded some further success with waterflooding in the late 1980s (Jurawn, 1988) Fram Exploration Trinidad Ltd (Fram) signed an Incremental Production Services Contract (IPSC) for the Inniss Trinity Field with Petrotrin in February 2010.

In July 2014 when Leni Gas and Oil (now Columbus) was considering acquiring the Inniss Trinity Field from Fram it was producing between 140 and 150 barrels of oil per day from about 25 active wells. At the time Leni Gas and Oil (LGO) was focussed on development of the nearby Goudron Field. It planned to transfer the Goudron workover experience and some of the workover equipment to the Inniss Trinity Field to significantly increase the production. LGO identified about 20 well reactivation targets. It quoted the stock tank oil originally in place at 68 million barrels with a possible upside of about 200 million barrels (Energy Business Review, July 2014). In 2015 LGO encountered financial difficulties with the uninsured loss of Goudron well GY-678 and it abandoned the acquisition of Trinity Inniss Field (LGO Energy PLC, 2016).

Fram's commitments under the IPSCA included a comprehensive technical review of the field to identify locations for infill drilling and candidate wells for workover activity, and the construction and maintenance of infrastructure and facilities. A site visit by Gaffney Cline in 2011 confirmed construction of roads, site office and ongoing workovers at a number of well locations. Of the original estimated 145 wells drilled in the field 15 of the best producing wells have been retained by Petrotrin (now Heritage) and do not form part of Fram's IPSC. Fram has taken over 69 wells but the balance of wells have not been located in the deep jungle or have previously been abandoned (Gaffney, Cline & Associates, 2011).

Fram commissioned a number of technical reviews of the field by More Consulting in 2010, Garcia 2011, Peak Petroleum Trinidad 2013, Siggerud 2014, and most recently IGSL in 2016. The wells in the Trinity Inniss Field have a cumulative oil production of about 22.9 million barrels to 30th April 2016 (International Geological Services Ltd, 2016). Herrera sand units 1 to 5 exhibit a combination of solution gas drive assisted by gravity drainage and possibly weak water drive recovery mechanisms giving an average recovery factor of about 35%. The original oil in place value (OOIP) is 67.95 MM barrels calculated by volumetric estimates (Taylor, 1987). Opportunities remain for continued development of the field. Two recompletion candidates, five drilling candidates and resumption of waterflooding were proposed (Garcia, 2011). By July 2011 Fram had rehabilitated 12 wells that were producing 40 barrels of oil per day. Volumetric estimates and reserve calculations based on isopach maps indicate that some fault compartments may be depleted and others may have remaining unproduced reserves. Structure maps on Herrera Sand horizons 3 and 4 highlighted the presence of more prolific oil producing reservoirs along the axial areas of the structure and on the updip parts of the overthrust limbs of each thrust fault segment (International Geological Services Ltd, 2016). Fram's development plan includes several new optimally placed infill wells (Gaffney, Cline & Associates, 2011).

However, an accessible source of CO_2 from Trinidad's petrochemical industry could make CO_2 EOR a more economical and environmentally friendly way to increase production from mature fields than infill drilling. The application of CO_2 EOR is in line with Republic of Trinidad and Tobago Government strategy. Predator will fund the cost of two pilot CO_2 production and injection wells on the Innis Trinity Field in return for 50% of revenues from production under its WPA with FRAM. Initially two wells, AT-5X and AT-

13 will be used to test the Pilot CO_2 EOR concept before any expansion of the Project is undertaken. Predator has carried out a detailed reservoir study which identified the AT-4 Block as the optimum location for the Pilot CO_2 EOR. Upscaling a successful CO_2 EOR Pilot could yield additional undeveloped reserves of up to 8.9MMBbls from the Innis Trinity Field if miscible CO_2 flooding is achieved. If no vertical communication exists between the Herrera Sands miscible CO_2 flooding may be achievable in the Herrera 4 and 5 Sands. The initial CO_2 injection for reservoir re-pressurisation at AT-5X and AT12 during the pilot CO_2 EOR will determine whether the Herrera Sands are currently all in vertical communication.

3.5 Risks

The Inniss Trinity Field is a mature onshore oilfield. Some opportunities remain to increase production from infill drilling, secondary oil recovery by water injection and enhanced oil recovery with CO_2 injection. There are some risks in accessing the potential developed non-producing reserves and undeveloped reserves in the Inniss Trinity Field. These include uncertainties about the original oil initially in place, structural complexity and trapping, reservoir complexity and response to secondary and enhanced oil recovery techniques. Challenges remain with the level of complexity of the structure across the field and the impact this has on hydrocarbon trapping (International Geological Services Ltd, 2016). Furthermore the absence of key historical well information (e.g. complete and accurate records of cumulative gas and water production by well stage) adds risks to the findings from the various geotechnical analyses carried out by Fram in terms of accurately representing the reservoir complexity, the reservoir fluid distribution, the current state of reservoir pressure depletion and the remaining production / reserves potential (Garcia, 2011). There are uncertainties in the static reservoir model particularly in relation to the effectiveness of fault seals and the compartmentalisation of the reservoir.

Predator had initially selected locations for infill wells. The locations assume that the southwest field extension is not fully drained by existing development wells and that the Herrera Sand channel axis runs northeast-southwest. Since AT87 was not perforated at the Herrera Sand 2 Horizon it is reasonable to assume that the southwest field extension is not fully drained. Furthermore, the assumption that the Herrera Sand 2 Horizon channel axis runs northeast-southwest is consistent with the 3D depositional model constructed by Siggerud for the Inniss Trinity Field (Siggerud, 2014).

While Predator recognises the potential for accessing additional undeveloped reserves by infill drilling its main focus is on investigating the potential for EOR using CO_2 injection. Based on Predator's economic analysis a successful CO_2 EOR operation on the Inniss Trinity Field delivers a better internal rate of return than infill drilling. Three heavy oil EOR CO_2 projects have been carried out by Petrotrin (now Heritage) in the Forest Reserve Field onshore Trinidad. One was considered successful recovering 8% of the original oil in place (Mohamed-Singh, SinghaL, & Sim, 2006). However, the oil properties and field characteristics are very different in the Inniss Trinity Field from the Forest Reserve Field.

According to two simple rules of thumb for CO_2 EOR, operators may expect an incremental oil recovery of either 10% of OOIP or 25% of the total of primary plus waterflood oil recovery (Fox & Avasthi, 2014). These figures are based on miscible CO_2 flooding, which is typically restricted to reservoirs deeper than 2,000ft with API oil gravity greater than 22 to 25 degrees and remaining oil saturations greater than 20%. While CO_2 flooding is not sensitive to lithology it is sensitive to reservoir characteristics. Reservoirs that have performed well under waterflooding typically will perform well with CO_2 flooding (Petroleum Technology Transfer Council, 1998). Knowing the flooding technique's performance in analog reservoirs is crucial. The pilot CO_2 injection project proposed by Predator is required to establish the oil recovery potential of CO_2 EOR in the Inniss Trinity Field.

In addition to the reservoir uncertainties outlined above (particularly the reservoir compartmentalisation) Predator's detailed operational plan has identified other risks to a successful CO_2 EOR operation in Block AT-4. The reservoir fracture pressure needs to be validated, from historical leak off tests if available, to constrain the CO_2 injection pressure. A major risk is the current condition of the casing in the candidate wells AT-4, AT-5x, AT12 and AT13. There is evidence for casing damage in well AT-4. Current casing integrity shear strength verification is critical if CO_2 is to be injected at 1500 psi pressure as proposed by the operational plan. This risk can be addressed by running downhole cement bond logs and pressure testing the casing with a remedial cement squeeze if necessary. There is evidence that Texaco's uncontrolled secondary recovery water flooding caused formation damage in the AT-23 Block. However, there is no evidence that Block AT-4 was subjected to water flooding. All these risks will be addressed by the proposed Pilot CO_2 EOR.

Predator's current operational plan involves the isolation of the Herrera No.2 sand in AT-5X and AT-13 by a basal cement bridge plug and an upper removable packer to facilitate CO_2 injection into and production from a single sand. The intention is to focus the CO_2 into a smaller rock volume area.

4.0 Resources

The volumetric estimate of STOIIP in the Herrera Units 1 to 5 made by Texaco originally for the field is 68 million barrels (MMBbl) based on an areal extent of the hydrocarbon bearing reservoirs of 580 acres fragmented into twenty two fault blocks (Taylor, 1987). In 2011 Gaffney Cline used an area of 1,450 acres to calculate a STOIIP of 150 MMBbl. A review of the existing field maps for Herrera Sand units gave a value of about 626 acres, a net oil sand in Herrera Units 1 to 5 of about 140 ft and a STOIIP of 89 MMBbl.

Table 1 Inniss Trinity Field STOIIP Estimate

Area (acres)	626
Net Oil Thickness (ft)	140
Porosity	19%
Oil Saturation	55%
Formation Volume Factor	1.256
STOIIP (MMBbl)	89

In 2011 Garcia carried out a reservoir engineering review of the Inniss Trinity Field using Texaco's conservative value of 68 MMBbl STOIIP as a starting point and calculated recoverable primary reserves for solution gas drive (SGD) and water drive (WD) reservoirs. The water drive recovery factor for the combined recoverable reserves approximates the actual total production achieved by 30th April 2016 (Table 2).

Table 2 Summary of OOIP and Recoverable Reserves (Source: Garcia 2011)

Reservoir	OOIP (MBO)	Cum. Prod. (MBO)
Herrera Unit 1	2,900	792
Herrera Unit 2	23,226	4,540
Herrera Unit 3	20,732	8,254

Herrera Unit 4	12,839	5,641
Herrera Unit 5	8,253	3,541
Totals	67,950	22,768

The recovery up to 30th April 2016 has been by primary solution gas drive and a period of secondary waterflood recovery with an overall recovery factor of 33.5%. An estimated 45.2 MMBbls of oil remains in place based on Table 2 above.

With respect to additional CO_2 EOR reserves on the Inniss Trinity Field the rule of thumb discussed in Section 3.5 above can be applied to the OOIP of 89 MMBbls and cumulative oil production of about 23 MMBbls (Table 2) to yield additional undeveloped reserves of 8.9 MMBbls or 5.7 MMBbls respectively. This assumes miscible CO_2 flooding. Immiscible CO_2 flooding at depths less than 2,000 ft can have CO_2 EOR recovery factors of 5% to 6% based on data from analog fields in the Illinois Basin (Knepp et al, 2009). Immiscible CO_2 EOR could produce additional undeveloped reserves of 5.3 MMBbls. These incremental recoveries can only be included in reserves after a favourable production response from the Herrera Reservoir Sands in a representative pilot CO_2 EOR project (SPE, AAPG, WPC, SPEE, SEG, SPWLA, EAGE, 2018).

The current Innis Trinity Field CO_2 EOR Project can be classified as having gross contingent resources as defined by the Petroleum Resource Management System (SPE, AAPG, WPC, SPEE, SEG, SPWLA, EAGE, 2018) attributable to Heritage (FRAM is the operator) with development pending, where project activities are ongoing to justify commercial development in the foreseeable future (see Appendix 2). If the Pilot CO_2 EOR is successful it must be scaled up for performance and cost for the full Innis Trinity Field assuming that enough volumes of CO_2 are available locally at the appropriate price.

Table 3 Contingent Oil Resource Innis Trinity Field CO_2 EOR Project

	Gross (MMBbls)			Net Attributable	Chance of Commerciality	Operator
	Low Estimate	Best Estimate	High Estimate	Profit share after Predator investment recovery 50:50		
Innis Trinity Field	5.3	6.8	8.9		CO_2 EOR Development Pending	FRAM

The best estimate contingent oil resource of 6.8 MMBbl is based on 10% recovery by miscible CO_2 flooding of Texaco's conservative value of 68 MMBbl STOIIP. The high estimate of 8.9 MMBbl is based on 10% recovery by miscible CO_2 flooding of our 89 MMBbl STOIIP estimate. The low estimate of 5.3 MMBbl is based on 6% recovery by immiscible CO_2 flooding of the 89 MMBbl STOIIP estimate.

It is not possible to calculate the net attributable to Predator at this stage. The WPA assigns profit 50:50 between Predator and FRAM, after Predator investment recovery, unless Predator exercises its option to purchase FRAM on or before 31st December 2019. The estimated post tax revenues from the AT-4 Block Pilot CO_2 EOR Project, if successful, would recover Predator's estimated investment of approximately US$ 750,000.

5.0 Infrastructure and Environmental Issues

Trinidad has established oil and gas infrastructure including a decommissioned refinery, a 4 Train LNG plant with 2 bcf/d capacity, 1,835 km of gas pipelines, 587 km of oil pipelines, and two oil storage and export terminals.

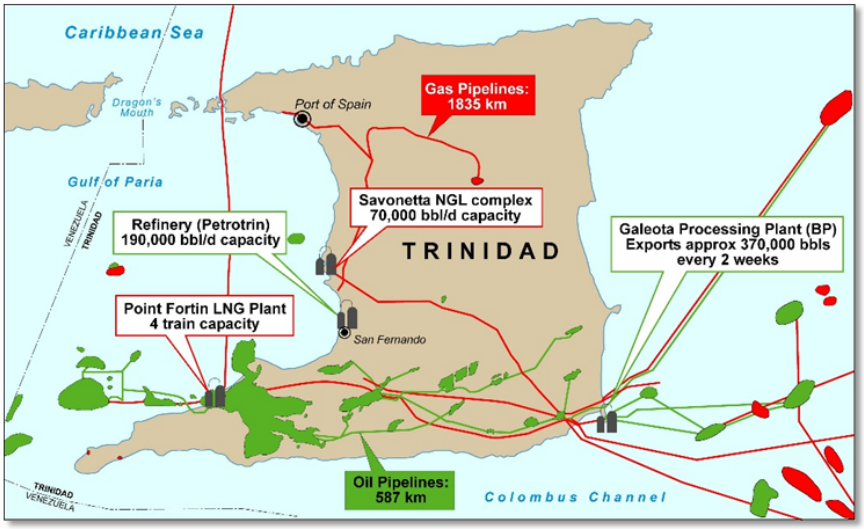

Figure 8 Trinidad Infrastructure

Trinidad and Tobago has a large industrial base comprising mostly petrochemical and gas based plants which, excluding 2.4 bcfgd used for LNG, consume about 1.6 bcfgd. These include seven world scale ammonia plants which collectively vent about 250-300 MMCFD of virtually pure CO2 into the atmosphere (Persad, Potential for Increasing Recovery in mature Fields Onshore & Offshore Trinidad using Carbon Dioxide, 2015). All of these plants are located in the large Point Lisas Industrial Estate (PLIPDECO) onshore the west coast of Trinidad about 40 kms from the Inniss Trinity Field.

A site visit by Gaffney Cline in 2011 confirmed that Fram Trinidad has a fit for purpose HSE policy in place which is implemented by field staff. Prior to signing the IPSC a third party environmental site assessment study was commissioned by Fram in 2010. The study defined an environmental baseline whereby all prior environmental issues remain the responsibility of the previous operator Petrotrin. Several areas of concern were identified in the report and Fram advised that it considered the costs of environmental clean up to be in the order of US $1 million (Gaffney, Cline & Associates, 2011).

6.0 Special Factors

6.1 Country Overview

Trinidad and Tobago has a population of 1.2 million and is one of the most prosperous countries in the Caribbean thanks largely to petroleum and natural gas production and processing. Pitch Lake on Trinidad's southwestern coast is the world's largest reservoir of asphalt. The island is mostly plains with some hills and lows with a tropical climate. It is outside the usual path of hurricanes and other tropical storms. Trinidad and Tobago is a parliamentary republic with an English common law legal system. English is the official language.

Energy production and downstream industrial use dominate the economy. Oil and gas typically account for about 40% of GDP and 80% of exports but less than 5% of employment. Trinidad and Tobago is home to one of the largest natural gas liquefaction facilities in the Western Hemisphere. Trinidad and Tobago produces about nine times more natural gas than crude oil on an energy equivalent basis with gas contributing about two-thirds of energy sector government revenue. The US is the country's largest trading partner, accounting for 28% of its total imports and taking 48% of its exports. International communications are excellent with good local services (Central Inteligence Agency , 2017).

6.2 Fiscal Regime

The Trinidad and Tobago government grants petroleum licences under licensing rounds. Royalty and other taxes are payable to the State based on the production levels and crude prices of production from each licence. In the case of the Inniss Trinity Block Fram acts as a service contractor to Heritage, the owner of petroleum rights in the Block, under an Incremental Production Service Contract (IPSC). Reserves are attributable to Heritage. Under the IPSC Fram is paid a service fee out of which Fram is required to bear all exploration, capital and operating expenditure and, in addition, to pay all royalties and taxes associated with its operation on the block. The service fee is based on the market value of the petroleum delivered less a number of deductions (Royalties, Notional Overriding Royalty, Facilitation Fee, Licence Fee and other deductions). These are specified in the original IPSC, but some have been adjusted to reflect changing market conditions.

7.0 Conclusion

Predator Oil and Gas Trinidad Ltd (Predator) has negotiated an agreement with FRAM Exploration (Trinidad) Ltd (FRAM) a wholly owned subsidiary of Columbus Energy Resources PLC (Columbus) whereby Predator will fund and help plan a CO_2 Enhanced Oil Recovery Pilot Project in the Inniss-Trinity Field, which is operated by FRAM Exploration Trinidad Limited (FRAM). FRAM is a fully owned subsidiary of Columbus. As part of Predator's agreement with FRAM, Predator has the right to purchase FRAM through a Share Purchase Agreement (SPA) on or before 31st December 2019 for US$4.2m if the CO_2 pilot project is a success. If the Pilot CO_2 EOR is successful FRAM will pay Predator 100% of the Market Value (less costs and deductions) of any crude oil produced until full cost recovery, following which net proceeds will be split 50/50.

This CPR provides an independent estimate of the additional contingent oil resources (SPE, AAPG, WPC, SPEE, SEG, SPWLA, EAGE, 2018) that can be accessed by a CO_2 EOR Project on the Innis Trinity Field. In terms of project maturity, the CO_2 EOR Project is classified as Development Pending. It is a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. The AT-4 Block Pilot CO_2 EOR Project will address all the risks and uncertainties identified in Section 3.5 above.

Appendix 1

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Appendix 2

Petroleum Reserve Definitions

This Glossary provides high-level definitions of terms used in reserves evaluations by the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).

DEFINITIONS

Reserves are those quantities of petroleum[1] which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

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

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

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

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

[1]PETROLEUM: For the purpose of these definitions, the term petroleum refers to naturally occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulphur, oxygen, and/or

nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide and hydrogen sulphide.

PROVED RESERVES

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

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

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

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

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

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

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

response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

UNPROVED RESERVES

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

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

PROBABLE RESERVES

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

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when(a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favourable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behaviour in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

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

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

RESERVE STATUS CATEGORIES

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

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

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

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

Behind-pipe reserves are expected to be recovered from zones in existing wells, which will required additional completion work or future recompletion prior to the start of production.

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

The following Glossary provides high-level definitions of terms used in resources evaluations by the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).

As with unproved (i.e. probable and possible) reserves, the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of quantities classified as resources. Such disclosure is left to the discretion of the countries or companies involved. Estimates derived under these definitions rely on the integrity, skill, and judgement of the evaluator and are affected by the geological complexity, stage of exploration or development, degree of depletion of the reservoirs, and amount of available data. Use of the definitions should sharpen the distinction between various classifications and provide more consistent resources reporting.

DEFINITIONS

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

TOTAL PETROLEUM-INITIALLY-IN-PLACE

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

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

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

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

RESERVES

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

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

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

CONTINGENT RESOURCES

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

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

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

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

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

PROSPECTIVE RESOURCES

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

ESTIMATED ULTIMATE RECOVERY

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

AGGREGATION

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

RANGE OF UNCERTAINTY

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

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

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

RESOURCES CLASSIFICATION SYSTEM

Graphical Representation

Figure 2.1 is a graphical representation of the definitions from the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

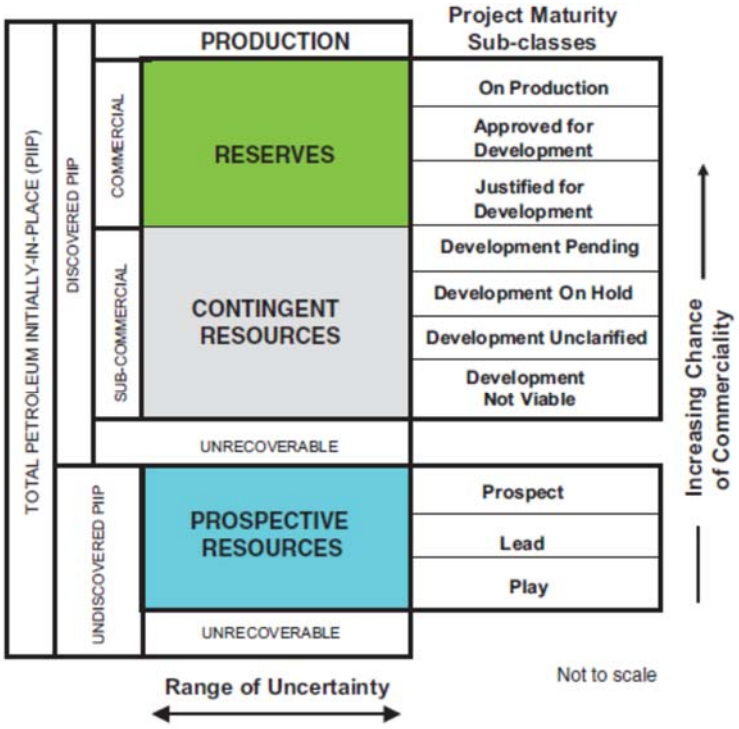

Figure 2.1—Sub-classes based on project maturity

As indicated in Figure 2.1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

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

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

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COMPETENT PERSONS REPORT

PREDATOR OIL & GAS HOLDINGS PLC

MOROCCO

SLR Ref: 501.00269.00003
Final
30 January 2020

BASIS OF REPORT

This document may contain information of a specialised and/or highly technical nature and the Client is advised to seek clarification on any elements which may be unclear to it.

Information, advice, recommendations and opinions in this document should only be relied upon in the context of the whole document and any documents referenced explicitly herein and should then only be used within the context of the appointment.

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1.0 Executive Summary

A Petroleum Agreement has been signed on 19th March 2019 between Predator Gas Ventures Ltd (a wholly owned subsidiary of Predator Oil & Gas Holdings Plc) and the Office National des Hydrocarbes et des Mines (ONHYM), acting on behalf of the Moroccan State, covering four exploration permits (Guercif I, II, III & IV), with an area of 7,269km^2. Predator will be the Operator of the licences. The Joint Ministerial Order was signed on 6th May 2019 and gazetted in the Bulletin Officiel No 6792 1er kaada 1440 4th July 2019.

There are three petroleum systems in the Guercif basin with reservoirs in sub salt Triassic clastics, Lower Jurassic reef complexes, Middle Jurassic sandstones, and Tertiary clastics (ERICO, 1986). Predator has prioritised the Tertiary biogenic and thermogenic gas plays. These Tertiary Neogene gas plays are commercial in the very similar Gharb basin to the west where good seismic, processed with Kirchhoff PSTM and AVO has resulted in a remarkably high discovery rate. Predator has mapped the Tertiary Moulouya Prospect based on seismic amplitude anomalies. The best case gas initially in place (GIIP) is calculated as 646 BCF based on an area of closure of 40.5 km^2 mapped near exploration well GRF-1. The closure is supported by clear seismic amplitude anomalies seen on 2003 vintage data. A sub-salt Triassic prospect with an area of closure of 38 km^2 has also been identified by Predator.

Table 1-1 Prospective Resources Guercif Permit

			Gross			Net Attributable			
Gas Prospective Resources BCF	GIIP	Recovery Factor	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Operator
Guercif Tertiary	646	66%	148	426	879	111	320	659	Predator
Guercif Triassic	515	40%	77	206	378	58	155	283	Predator
Total	1161		225	632	1257	169	474	943	

The net best estimate for the Tertiary Moulouya Prospect is the probable volume of recoverable hydrocarbons based on recovery factors of 66% estimated production over 13 years. To assess the chance of development the Tertiary prospective resources have been evaluated using an economic model constructed by Predator and reviewed by SLR to confirm validity. Prospective Resources are those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations. Based on the potential size of the discovery the project is likely to be commercially viable.

The Guercif Permits, when they are awarded to Predator, will represent an opportunity to develop an onshore gas play similar to SDX Energy's successful Gharb Basin permits where production commenced in 2008.

2.0 Introduction

SLR Consulting (Ireland) Ltd ('SLR') of 7 Dundrum Business Park, Windy Arbour, Dublin 14, Ireland, has been commissioned by Predator Oil and Gas Ventures Limited (the "Company") to complete a Competent Person's Report (the "CPR") on the company's Guercif Permit (net interest 75%) asset.

This CPR has been prepared in accordance with the requirements of paragraphs 131 to 133 of the ESMA update of the CESR recommendations in respect of the consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive to include an independent expert's report (CPR) in a prospectus document. Resources are reported in accordance with The Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation

Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018). The deterministic incremental approach was chosen because the Guercif asset is at the pre discovery stage and the full range of reliable values for input parameters to a probabilistic approach are not available.

The CPR has been prepared by Mr Nick O'Neill, with assistance from Mr Richard Vernon and Mr Martin Davies, based on data supplied by the Company, a literature search carried out by SLR and some independent verification. The data comprised details of permits and acreage interests, basic exploration geological and geophysical data, interpreted data, and technical presentations. SLR has exercised due diligence and independent analysis where appropriate on all technical information supplied by the Company. SLR has not independently checked title interests with Government or licence authorities.

Richard Vernon has more than 30 years' experience in the energy sector. After graduating with a business degree majoring in accounting and marketing, he worked as a financial analyst specialising in the Canadian oil and gas sector. He then joined the London based consultancy Petroleum Economics Limited and covered all aspects of the international oil and gas industry, including exploration/production and refining/marketing, taxation and licensing regimes, supply/demand/price strategies and forecasting, etc. for a wide range of clients including governments, international institutions and national and private oil companies. Subsequently, he moved to the US based multinational oil and gas company Phillips Petroleum Company as Director of External Affairs, responsible to the Managing Director of the Europe/Africa Division.

Martin Davies BSc FGS Chart Geol EurGeol PESGB is a Senior Petroleum Geologist. Mr Davies joined SLR in 1993 after 18 years international experience in oil and gas exploration development and production, both onshore and offshore, with British Petroleum. He has worked in Ireland, the UK, North Africa, the Middle East and the Far East. He has also worked on a number of exploration portfolio evaluations for UK and Irish based independent oil companies.

Nick O'Neill BSc MSc PGeo EurGeol MEI PESGB M AAPG is a Senior Petroleum Geologist and Director of SLR Ireland. Mr O'Neill joined SLR in 1994, having worked internationally in oil exploration operations since 1977. He was operations manager in the Middle East for an oilfield service company. He obtained an MSc in Petroleum Geology in 1986. He was operations geologist with BP and Shell in London and Aberdeen responsible for North Sea exploration operations. He has written a number of valuations and CPR reports on hydrocarbon properties in Ireland, the US, West Africa, and Italy for UK and Irish based independent oil companies.

SLR Consulting (Ireland) Ltd. has many years of experience undertaking independent expert studies and has completed Expert Reports and Valuations for listings on the London, Copenhagen, Dublin, Vancouver, Luxembourg and Australian Stock Exchanges.

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

INDEPENDENCE OF SLR

This competent persons' report has been prepared by Nick O'Neill who is professionally qualified and a member in good standing of the Institute of Geologists of Ireland, an institution relevant to the activity being undertaken, and who is subject to the enforceable rules of conduct. Nick has at least five years' relevant professional experience in the estimation, assessment and evaluation of oil and gas projects. Nick is independent of Predator Gas Ventures Ltd, its directors, senior management and its other advisers; has no economic or beneficial interest (present or contingent) in the company or in any of the oil and gas assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

SLR confirms that, based on the information provided to it and to the best of its knowledge, no material changes have occurred since the date of the competent person's report the omission of which would make the competent person's report misleading. No site visit has been made because no infrastructure associated with the project exists.

We confirm that SLR is responsible for this letter and the contents of the CPR and we declare that we have taken all reasonable care to ensure that the information contained in this letter and the CPR is in accordance with the facts and there is no omission likely to affect its import.

Yours faithfully,

Mr. Nick O'Neill

Director

SLR Consulting (Ireland) Ltd.

3.0 Legal Overview

An application for an exclusive exploration and appraisal licence has been accepted by the Office National des Hydrocarbes et des Mines (ONHYM) acting on behalf of the Moroccan State. When entered into, the Petroleum Agreement will cover four exploration permits (Guercif I, II, III & IV), covering some 7,269km^2 east of the producing fields in the Gharb Basin and northwest of the Tendrara gas project. Predator will be the Operator of the licence. A Petroleum Agreement has been drawn up between Predator and ONHYM and was signed on 19th March, 2019.

The Minimum Exploration Work Programme and budget that has been agreed for these blocks for the thirty (30) months from the signing on 19th March 2019 is as follows:

WORK PROGRAMME & BUDGET	US$ MM
250 kms of 2D seismic reprocessing for AVO analysis	150,000
Drilling One Exploration Well (2,000 meters commitment depth)	2,000,000
Guercif Geological Studies – NuTech Petrophysics Palaeogeography, Source Rock Studies, Migration routes Moroccan Gas Market Study	125,000 40,000
Guercif Licence G & A – US$290,000 p.a. (2.5 years)	725,000
ONHYM Training Budget (2.5 Years)	104,000
CONTINGENCY @ 10%	314,000
Total *Exchange Rate 1.28*	3,458,000

It is not possible at this stage to know where the concentration of expenditure will occur.

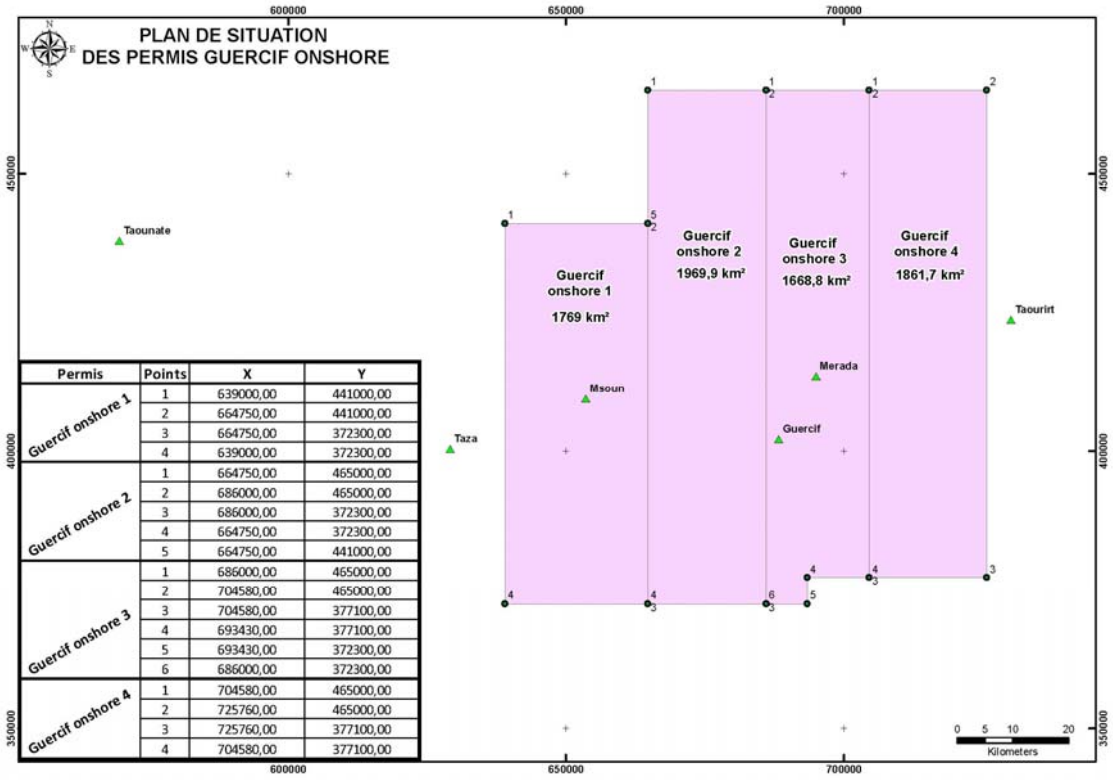
The Minimum Exploration Work Programme and budget that has been agreed for these blocks for the PR – Legal Extension period of thirty-six (36) months from the signing of the extension period is as follows:

WORK PROGRAMME & BUDGET	US$ MM
Acquire and Process 200 sq. km. of 3D seismic over Tertiary prospects Including AVO, Rock Property and Inversion Modelling	2,500,000
Drilling One Exploration Well (2,000 meters commitment depth)	2,000,000
Guercif Geological Studies – NuTech Petrophysics for the Jurassic Well post-mortems Jurassic and integration with palaeogeographic model Development options for discovered gas in Initial Period	125,000 40,000
Gravity and Magnetic modeling of existing data	60,000
Guercif Licence G & A – US$290,000 p.a. (3 years)	870,000
ONHYM Training Budget (3 Years)	125,000
CONTINGENCY @ 10%	572,000
Total *Exchange Rate 1.28*	6,292,000

The Minimum Exploration Work Programme and budget that has been agreed for these blocks for the second extension period of thirty (30) months from the signing of the extension period is as follows:

WORK PROGRAMME & BUDGET	US$ MM
Acquire and Process 400 sq. km. of 3D seismic over Jurassic prospects Including AVO, Rock Property and Inversion Modelling	4,500,000
Drilling One Exploration Well to test Jurassic prospectivity (2,750 meters commitment depth)	5,000,000
Guercif Geological Studies – analyse well results in regional context Investigate scope for applying C02 and Water Flood EOR experience to Moroccan oil discoveries to improve well productivity	50,000 50,000
Guercif Licence G & A – US$290,000 p.a. (2.5 years)	725,000
ONHYM Training Budget (2.5 Years)	104,000
CONTINGENCY @ 10%	1,043,000
Total *Exchange Rate 1.28*	11,472,000

Predator will, on award, have a 75% interest in this permit, with ONHYM having a carried 25% interest in the exploration phase. ONHYM will contribute its share of costs once commercial production is declared. The location of the four Guercif permits can be seen below.



Permis	Points	X	Y
Guercif onshore 1	1	639000,00	441000,00
	2	664750,00	441000,00
	3	664750,00	372300,00
	4	639000,00	372300,00
Guercif onshore 2	1	664750,00	465000,00
	2	686000,00	465000,00
	3	686000,00	372300,00
	4	664750,00	372300,00
	5	664750,00	441000,00
Guercif onshore 3	1	686000,00	465000,00
	2	704580,00	465000,00
	3	704580,00	377100,00
	4	693430,00	377100,00
	5	693430,00	372300,00
	6	686000,00	372300,00
Guercif onshore 4	1	704580,00	465000,00
	2	725760,00	465000,00
	3	725760,00	377100,00
	4	704580,00	377100,00

Figure 1 Location of Guercif Permits

4.0 Geological Overview

4.1 Guercif Basin

The Guercif basin is a young Neogene Basin developed over the north-eastern extension of the Middle Atlas structural trend **(Figure 2).** It contains a sequence of Permo-Trias and Jurassic rocks, but Cretaceous rocks appear to be absent (probably eroded). Underlying the Mesozoic are older Palaeozoic and Pre-Cambrian rocks of which the Upper Carboniferous is proved locally. Silurian hot shales (the classic North African source rock) are known to the south-east on trend in the Middle Atlas, but are unproven so far in the Guercif basin.

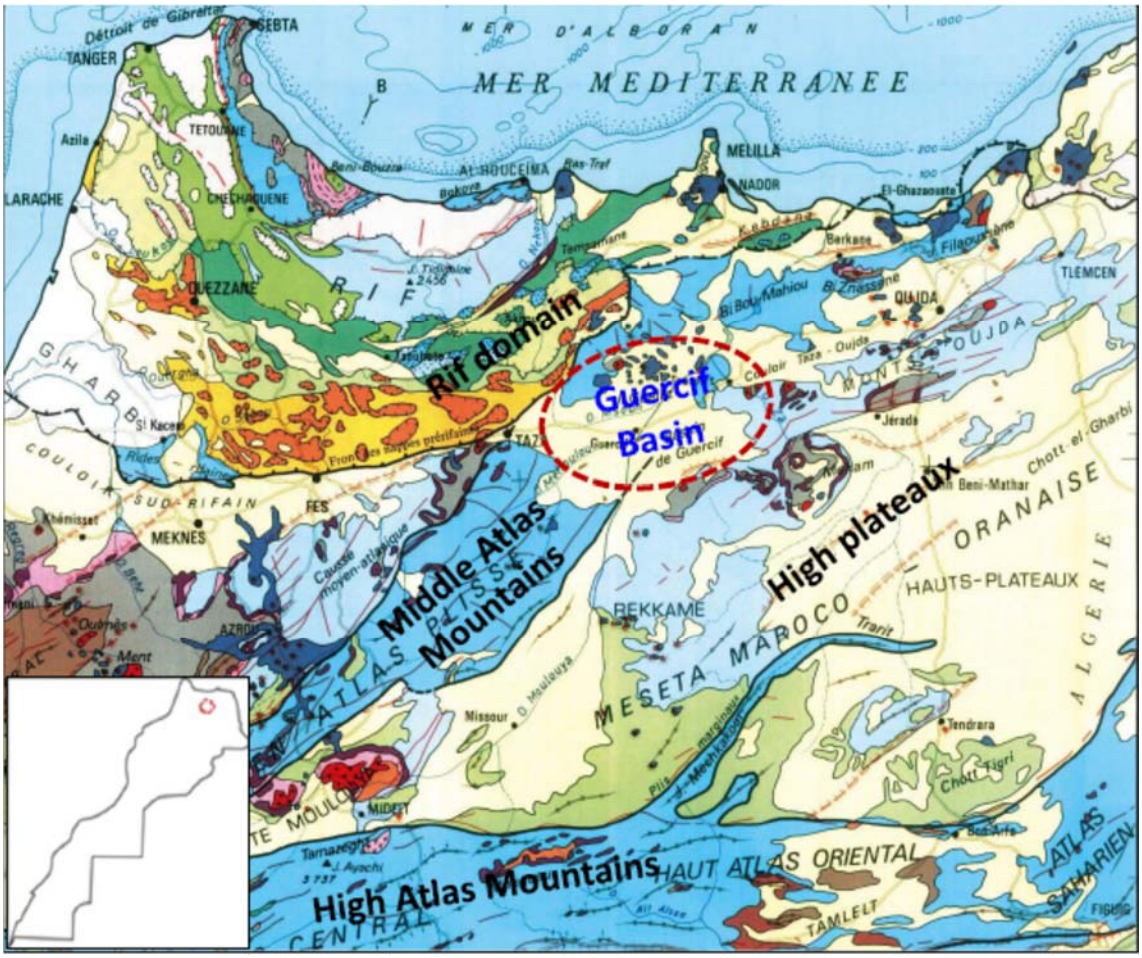


Figure 2 Schematic geological map showing Guercif Basin (after ONHYM)

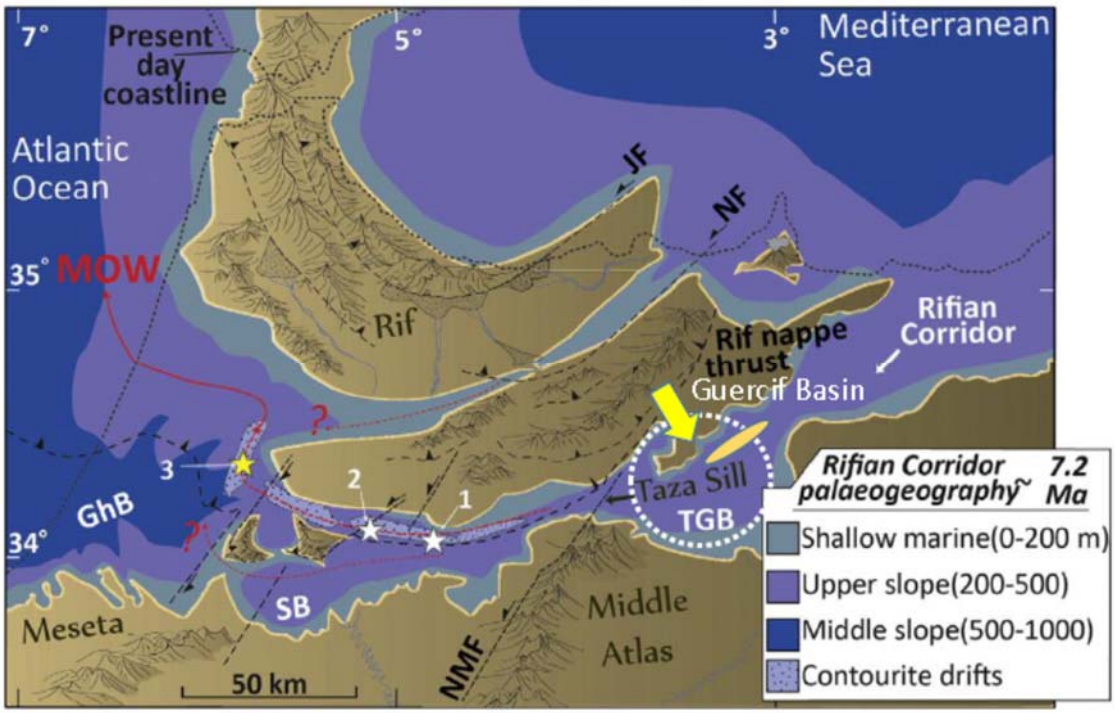


Figure 3 Late Tortonian-Early Messinian palaeogeography of Northern Morocco showing relationship between Guercif, Sais (SB) and Gharb (GhB) basins (Capella et al 2017)

The Neogene Taza-Guercif basin is one of a number of remnants of the basinal South Rifian Corridor that connected the Atlantic Ocean to the Mediterranean Sea during the Miocene **(Figure 3).** The Gharb, Sais, Fes-Meknes and Taza-Guercif basins were interconnected until the late Miocene. The Guercif basin is located on the foreland of the eastern sector of the Rif Belt and has a hybrid structure influenced both by the Rif orogenic belt to the north and northwest and the Middle Atlas Shear Zone to the southwest. It has characteristics of both a foredeep and a basin that evolved in a strike-slip setting. The oldest sediments in the Neogene basin are Tortonian in age. The basin fill comprises continental and marine sediments over 2000 metres in thickness. The basin depocentre migrated southwards during deposition in response to the advancing Rif front (Bernini, 1999) (M. Bernini, 2000), (W. Krijgsman, 1999) (W.Krijgsman, 2000) (R. Gelati, 2000) (F. Sani, 2000).

The earliest sediments of the Neogene are fluviatile sandstones and conglomerates which range from a few metres to hundreds of metres in thickness. These sediments are absent in some areas and are onlapped by shallow marine to outer shelf siltstones, mudstones and sandstones. These are capped by a thick, more basinal sequence of “blue marls”, thick turbiditic sandstones and gypsiferous marls which form a good seal. This is overlain in turn by a marine marginal to lacustrine sequence of thin bedded mudstones, sandstones and limestones. The final sediments are fluvial conglomerates and sandy limestones.

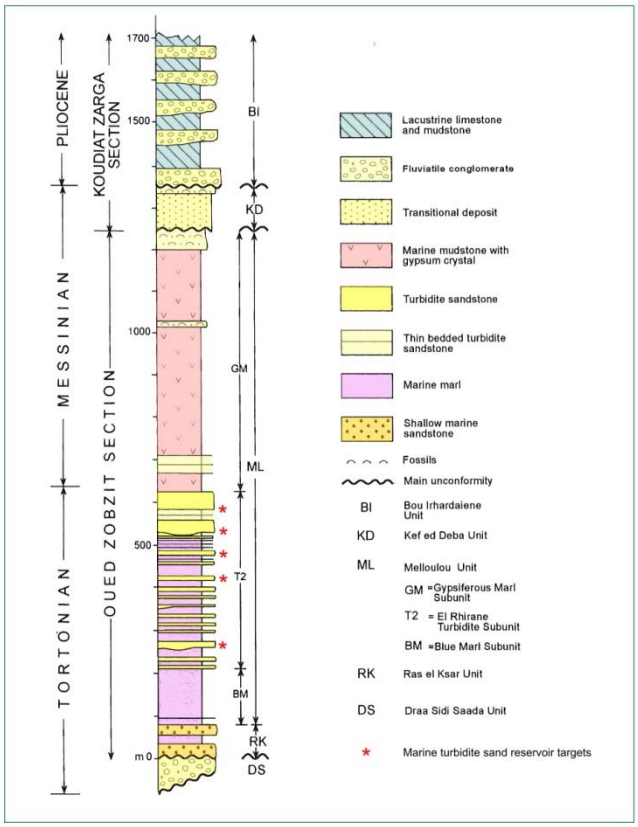


Figure 4 Taza - Guercif Basin Neogene stratigraphic sequence as mapped in Oued Zobzit and Koudiat Zarga (Gelati et al 2000)

Detailed mapping in the south and southwest parts of the Guercif basin (R. Gelati, 2000) has demonstrated the widespread occurrence of marine turbiditic sands in the upper half of the Tortonian sequence (Figure 4). These sands form the main target for the Neogene biogenic and thermogenic gas play, with basal Tortonian sands and conglomerates as a secondary objective.

At least six major compressional phases occurred in the basin in the Miocene to Pleistocene period.

Late Cenozoic volcanism occurs in two phases in the Guercif area. Late Tortonian to middle Pliocene volcanism occurs in the northern parts of the basin. This was followed by more extensive Pliocene and Quaternary volcanism in both the northern and southern parts of the basin (Hernandez J., 1985).

The present-day Guercif basin covers a wide area. Seismic and gravity data show that the basin comprises several parts. The main Guercif graben is more restricted in size and covers the western part. This deep graben is likely to be the most prospective part of the basin for biogenic gas from rapidly buried Neogene. Two wells (GRF-1, MSD-1 – Figure 6) drilled in this area both targeted Mesozoic oil plays as the Neogene was not considered prospective at the time.

4.1.1 Structure

The Guercif basin of northern Morocco occupies a 50 x 60 km area where the transpressional Middle Atlas Mountains terminate and abut the Rif thrust belt (Gomez F., 2000). The name “Guercif basin” refers to the present-day, physiographically expressed basin. We refer to the Mesozoic rift system (including the part in the Guercif basin) as the “Middle Atlas rift.” The smaller Neogene extensional

system depocentre is termed as the "Guercif graben" (see Figure 2). The Neogene Guercif basin is superimposed on an early Mesozoic rift basin and, in contrast to late Cenozoic uplift of the Middle Atlas fold belt, the Guercif basin experienced considerable subsidence during the late Neogene and Quaternary.

Most of the late Miocene deposition was concentrated in the Guercif graben, which contrasts with the wider physiographic expression of the basin today. Geohistory analysis indicates that tectonic subsidence persisted until the Messinian, and sediment loading continued to drive subsidence, even after extension stopped.

Prior to the opening of the Strait of Gibraltar, the Atlantic Ocean and Mediterranean Sea were connected via the "Rifian corridor" seaway, which flowed through what is now the Guercif basin, constricted during the Messinian (7.25–5.2 Ma). Following closure of this narrow seaway, the Messinian desiccation event of the Mediterranean Sea ensued (this event is also known as the Messinian salinity crisis).

Gravity data was used to map the extent of known and possible salt diapirs, most of which are located primarily on the south-eastern side of the Guercif basin. Recent mobilization of some of these diapirs is suggested from field observations documenting locally chaotic structures involving upper Miocene and Pliocene strata.

4.1.2 Source rocks

The Silurian "Hot Shale", the Devonian or the Carboniferous are likely to be present over at least part of the Guercif basin. All these units are proven source rocks in the Middle or High Atlas and adjacent areas, and are likely to be mature for oil and gas. Additional source rocks are also likely in the lower Jurassic and should be mature for oil in the deeper parts of the basin which are buried down to at least 7kms in some areas.

Known source rocks are found in the Mesozoic strata of the northern Middle Atlas and the Paleozoic strata of the High plateau/Missour basin (e.g. (Beauchamp W., 1996); (Zizi M., 1996b)), including Middle Carboniferous (Namurian) shales in the Missour basin showing up to 11% total organic carbon (TOC) and Lower Jurassic (Pliensbachian) calcareous mudstones with 4% TOC (Beauchamp W., 1996). Recent work (M. Rachidi, 2009), (Bodin S., 2011), (Sachse V. F., 2012) suggest a more widespread presence of lower Jurassic source rocks across both the High and Middle Atlas belts, including the areas close to the Guercif basin (Figure 4).

Geochemical sampling and a micro-seep survey confirm an active petroleum system for both oil and gas in the Mesozoic and a biogenic gas system in the Neogene (Geo-Microbial Technologies Inc, March/April 2007). The main plays in the Mesozoic are likely to be stratigraphic traps or traps sealed beneath Triassic salt. The presence of Triassic salt in the basin is proven with numerous salt diapirs, some reaching the surface.

In summary, the Guercif basin contains deeply buried rich source rocks similar to those seen in the Middle Atlas Mountains that have been buried deeper than in the mountain area. This deeper burial may provide a better opportunity for hydrocarbon maturation and entrapment. The hydrocarbon migration history needs to be studied and compared with the timing of tectonic events.

4.1.3 Reservoirs

Reservoirs in the Guercif basin include Triassic clastics, Lower Jurassic reef complexes, Middle Jurassic sandstones, and lower Tortonian clastics (ERICO, 1986). These reservoirs each have corresponding seals provided by Triassic evaporites, Middle Jurassic mudstones, and Tortonian mudstones (ERICO, 1986).

While reservoirs are postulated in the Triassic (the famous TAGI sands of Algeria), lower Jurassic limestones (mainly fracture porosity), middle and upper Jurassic sands (eroded on some highs), only the Miocene sand quality can be considered proven from field outcrops along depositional strike. The Miocene sands are sealed by the gypsiferous Mio-Pliocene marls.

The geological reservoir model is of large scale channelized Miocene Messinian and Tortonian sands reworked by bottom currents and local smaller scale turbidite channel systems that feed into the basin from the GRF-1/MSD-1 High **(Figure 5).**

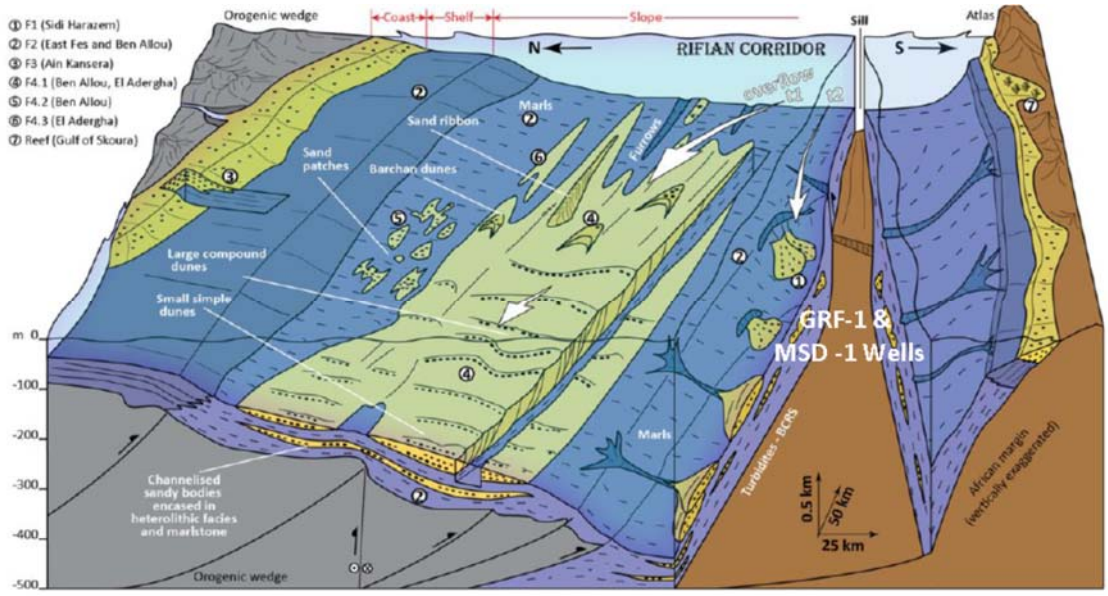


Figure 5 Geological reservoir model in a deep foreland basin seaway (Capella et 2017)

5.0 Exploration History and Database

5.1 Exploration History

Petroleum exploration in Morocco started in the period 1900 to 1920 in the Rharb (or Gharb) Basin and the first oilfield was discovered in 1923. Exploration in the Guercif area began in the late 1950s with reconnaissance gravity and seismic surveys. More detailed gravity and seismic surveys were carried out in the 1960s. Data quality was very poor in these early surveys.

A reconnaissance permit was held over Guercif and Beni Znassen area from June 2005 to June 2007 by TransAtlantic Petroleum Corp. and Stratic Energy Inc. The permit covered a much larger area (13,750 km^2) that extended north to the Mediterranean coast. The permit encompassed two basins: a Mesozoic Rift Basin and the Neogene Guercif Basin which have been tested by five wells.

In January 2008, a portion of the Guercif-Beni Znassen reconnaissance license was converted into two exploration permits ("Guercif West & Guercif East") covering a total of 3,893 square kilometres. These two permits lie within the current Predator exploration permit block. In December 2010, TransAtlantic relinquished their interests in the Guercif exploration permits and transferred their exploration efforts to the Tselfat exploration permit.

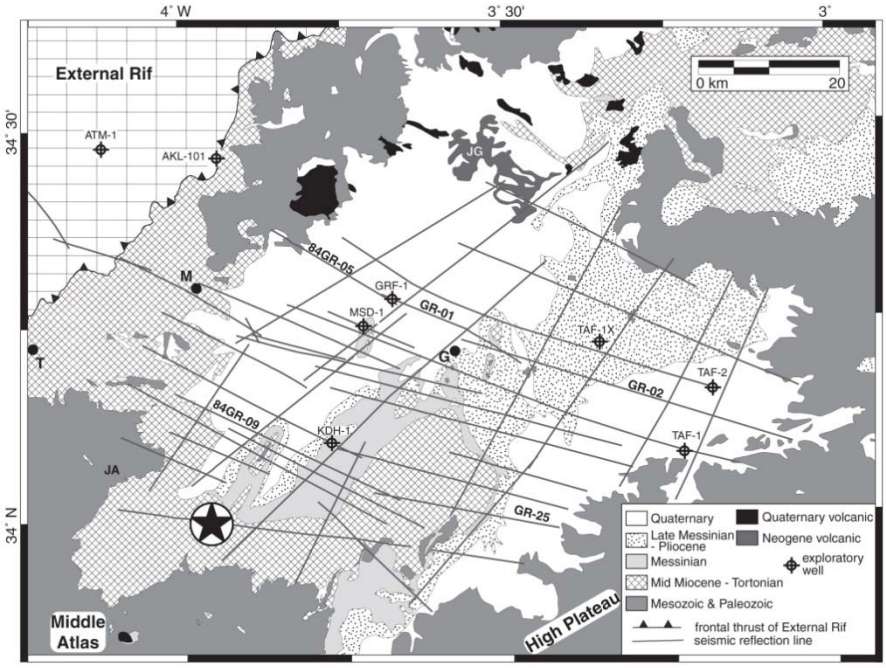


Figure 6 Map of Guercif Basin illustrating Neogene geology, well locations & seismic (Gomez 2000). Large star in SW shows location of Figure 4 stratigraphic section.

Since 2008 Circle Oil successfully explored for, and developed, Miocene gas targets in the Gharb Basin. In 2017 SDX Energy acquired these concessions in the Gharb Basin through its acquisition of Circle Oil. In 2018 SDX Energy, Sound Energy and PEL/FORPETRO hold exploration permits onshore Morocco and have ongoing exploration seismic and drilling programmes. Shell also has a reconnaissance contract onshore Morocco.

Wells:

There are four oil exploration wells (Table 5-1) and several stratigraphic wells drilled on the block of permits to date (Figure 6). The TAF-1 and TAF-2 wells were drilled by BRPM for coal exploration in the 1950s. Other shallow wells, such as PG-1 -2 and -3, were drilled for potash exploration. Oil drilling commenced in 1972 when Elf drilled GRF-1 followed by Phillips who drilled TAF-1X in 1979. MSD-1 and KDH-1 were drilled by ONAREP (now ONHYM) in the 1980's. Two further oil exploration wells, AKL-101 and ATM-1, were drilled on the north-west edge of the block. ATM-1 is located on the Prérif nappe (see Figure 6 for well locations).

Name	Year	Society	T.D(m)	TD Formation	Shows
GRF1	1972	ELF	1968	Top Jurassic	Gas
TAF-1X	1979	PHILIPS	3887	Paleozoic	calculated on well logs
MSD-1	1985	ONAREP	3608	Bajocian	calculated on well logs
KDH-1	1985-86	ONAREP	3801	Toarcian	calculated on well logs

Table 5-1 Well Data

A re-examination of the wireline logs by TransAtlantic in wells with Miocene and Upper Jurassic sands suggested that several gas sands may have been missed in these wells. TransAtlantic re-entered, logged and tested the MSD-1 well, originally drilled in 1985, in the fourth quarter of 2008. The logs and test failed to establish the presence of hydrocarbons. The authors have not seen data on this re-entry.

Seismic:

ONAREP carried out detailed studies in the period 2002-2005 which included a new seismic survey using 6 Vibroseis trucks and longer record lengths and processing using PSTM (TransAtlantic reprocessed 4,318 kms of 2D seismic shot over the area between 1968 and 2003 in 2006 using Kirchhoff PSTM. ONHYM only list 3,291kms of seismic in the Guercif basin proper. The additional 1,100kms may be from the Beni Znassen area further to the north. This reprocessing is said to have been quite successful in improving data quality on most of the data and seismic quality is now good enough in the best areas to identify amplitude anomalies and to postulate gas accumulations in the Neogene sands. Predator has provided sufficient examples of re-processed Guercif seismic to confirm quality and validity of seismic amplitude anomalies.

Table 5-2). A major geological study included a review of all existing geological and geophysical data, new geological mapping and geochemical sampling. This culminated in a major basin review report (Charrat, December 2004).

TransAtlantic reprocessed 4,318 kms of 2D seismic shot over the area between 1968 and 2003 in 2006 using Kirchhoff PSTM. ONHYM only list 3,291kms of seismic in the Guercif basin proper. The additional 1,100kms may be from the Beni Znassen area further to the north. This reprocessing is said

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Table 5-2 2D Seismic Data

Survey	YEAR	(Km)
GF 01 to 03	1968-69	34
GF04 to 21	1969	244
GA	1972	331
GR	1977	1300
PMT	1979	45
GR	1982	228
84GR	1984	446
85MS	1985	363
03 ML	2003	300
		TOTAL: 3291Km

Other Surveys:

TransAtlantic flew an aero gravity and magnetics survey (10,000 km) over the area in 2006 and carried out geochemical sampling coincident with surface and subsurface structures.

Two micro-seepage surveys were carried out by Geo-Microbial Technologies in 2006 and 2007. A total of 32 traverses were carried out over a 2500km^2 area and 731 soil samples were analysed in 2006 and 2007.

The results of the 2006-07 surveys (Geo-Microbial Technologies Inc, March/April 2007) identify several hydrocarbon types in the Guercif basin: thermogenic dry gas and some condensate around the GRF-1 well; oil and gas/condensate around the MSD-1 well, over the Jezira anticline and in southwest; and oil in all other anomalies. Particularly interesting is the abundant seepage in a large area around the TAF-1X well which appears to be oil rather than gas. The anomalies cover a larger area and have higher oil concentrations than the anomalies elsewhere. These surveys confirm there is an active hydrocarbon source system in the basin.

TransAtlantic's regional analysis yielded a number of large untested surface anticlines (up to 25 km in length) with associated surface geochemical anomalies. Its work confirmed the presence of source and reservoir rocks, seals and traps. TransAtlantic attempted to analyze the timing of oil maturation versus migration and trapping. In addition, it believed that two of the four wells drilled appeared to have missed pay opportunities.

5.2 Data

See Appendix A for a list of data and information sources. The list includes data on the four exploration wells in the block and some information on the stratigraphic wells drilled for coal and potash. Basin evaluation reports supplied by ONHYM include a range of seismic, gravity, magnetic and geochemical data.

There is a good selection of data on both the previous Guercif operator (TransAtlantic Petroleum) and on other onshore operators. There are also good government geology reports on the Guercif basin and surrounding areas.

We have also accessed a number of publications in journals and conference volumes. We have not had access to some of the work carried out by TransAtlantic Petroleum in the period 2005 to 2010.

6.0 Prospectivity

Neogene biogenic gas plays are commercial in the very similar Gharb basin to the west where good seismic data processed with Kirchhoff PSTM and AVO has resulted in a remarkably high discovery rate using 2D reprocessed seismic. In the Gharb basin the operator SDX Energy is now using 3D seismic, and 3D seismic acquisition in the Guercif Basin should improve success rates. In the Gharb Basin each structure is relatively small and a number of finds are required to make the play economically viable. Structural closures may be larger in the Guercif Basin where there is less minor faulting.

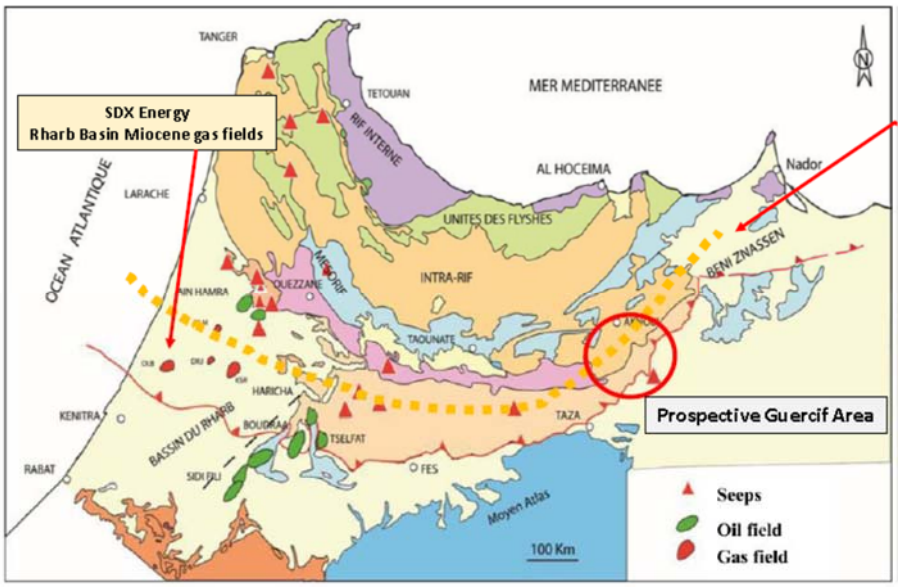


Figure 7 Prospective Fairway for Miocene Turbidite Gas Sands

In the Guercif Basin three possible plays are recognised, the Neogene biogenic gas play, the Jurassic oil (& gas) play and the Triassic oil & gas play.

NEOGENE

There are a number of seismic interpretations of the Neogene sequence in the Guercif basin. Zizi (Zizi, 2002) produced an isopach map of the Tertiary which shows a thickness of over 1,900m 25km SSE of Guercif town. ONHYM (Charrat, December 2004) produced a time structure map on Base Tertiary unconformity (same as base Neogene). Sani (F. Sani, 2000) contains a base Neogene time isopach map that is very similar and also shows the parts of the Neogene basin that were uplifted and eroded in the late Neogene-Quaternary. Predator generated a seismic amplitude anomaly map at the Tortonian sandstone level that indicated a closure of 40.5 km^2 named the Moulouya Prospect (Figure 8).

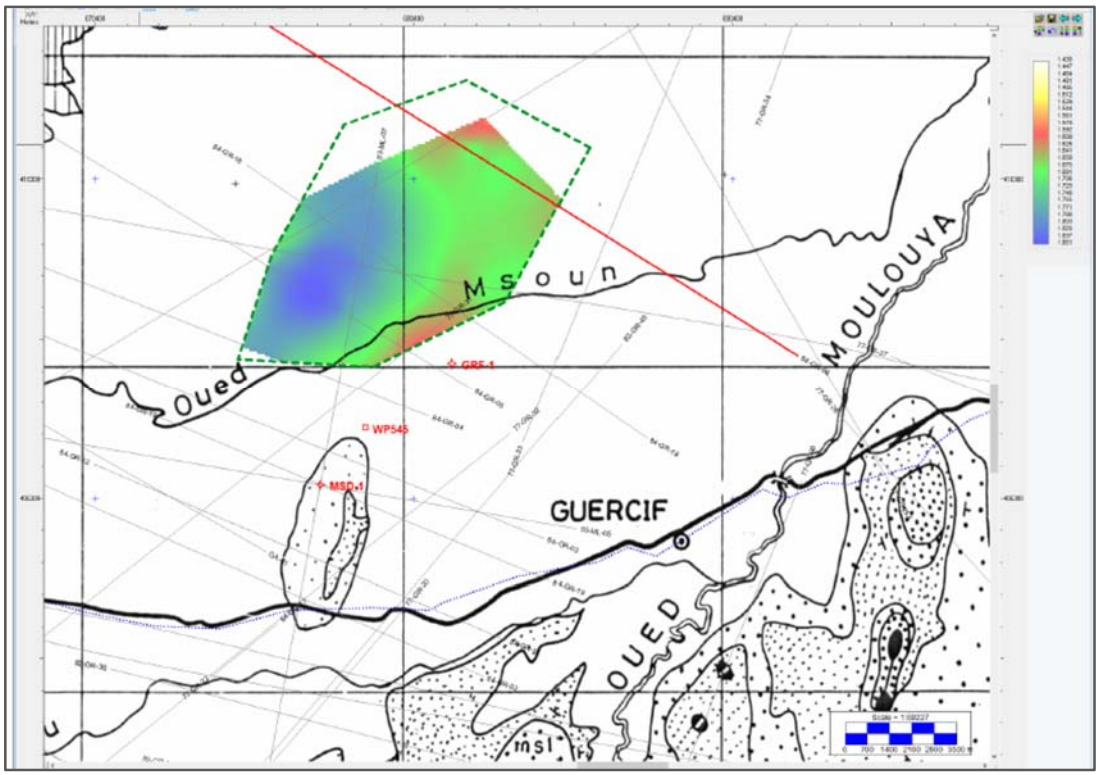


Figure 8 Amplitude map at top of Tortonian sandstone interval

The thickest isopachs are in the area around wells GRF-1, MSD-1 and north of KDH-1 which are west of Guercif town (see Figure 6 for locations). Here the Neogene-Quaternary reaches 1,900msecs TWT which equates to around 2,000m. This is confirmed by the GRF-1 well where the base Neogene was encountered at 1,932m. We believe the likely maximum thickness of the Neogene-Quaternary sequence in the Guercif basin is in the range 2,000 to 2,400 metres and that reservoirs in the interval 1,400m to 2,400m would be attractive targets for biogenic gas.

Based on field mapping (Bernini M. B. M., 1992), (R. Gelati, 2000), (Capella, 2017), turbidite and sandy contourite sands have been identified intercalated within the "blue marls" of the basinal Tortonian sequence. Typical sandstone beds at outcrop range from 1m to 40m in thickness and are deposited in local depocentres. This sequence is overlain by gypsiferous marls that make an excellent seal. Locally this gypsiferous sequence contains bedded lignites that could be a good biogenic gas source in the basinal areas.

The Anchois biogenic gas discovery in the Repsol/Dana Tangier Larache Offshore Permit suggests that thick sands and large accumulations can be found in these young Neogene basins. The deeper Miocene sands show high porosities and high net to gross. Net sand totalled 89m and the mean GIIP for Sand B has been estimated at 160 Bscf; the mean Sand A GIIP is 49 Bscf (Dana, 2010). These figures represent a high side case for the Guercif Permits.

The GRF-1 well encountered thin basalt/andesite lavas at the top of the Tortonian sequence immediately above the target sands and the lower seismic reflectors and seismic amplitude anomalies.

These volcanics are the same age as the late Tortonian to middle Pliocene volcanics known from outcrop in the northern part of the permit area (Hernandez J., 1985).

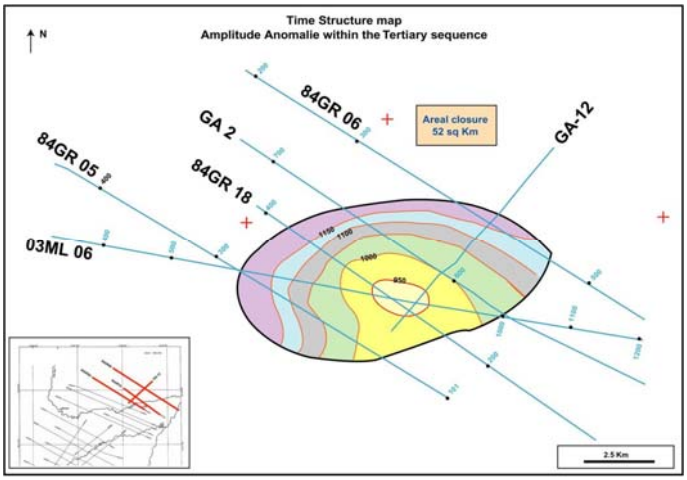
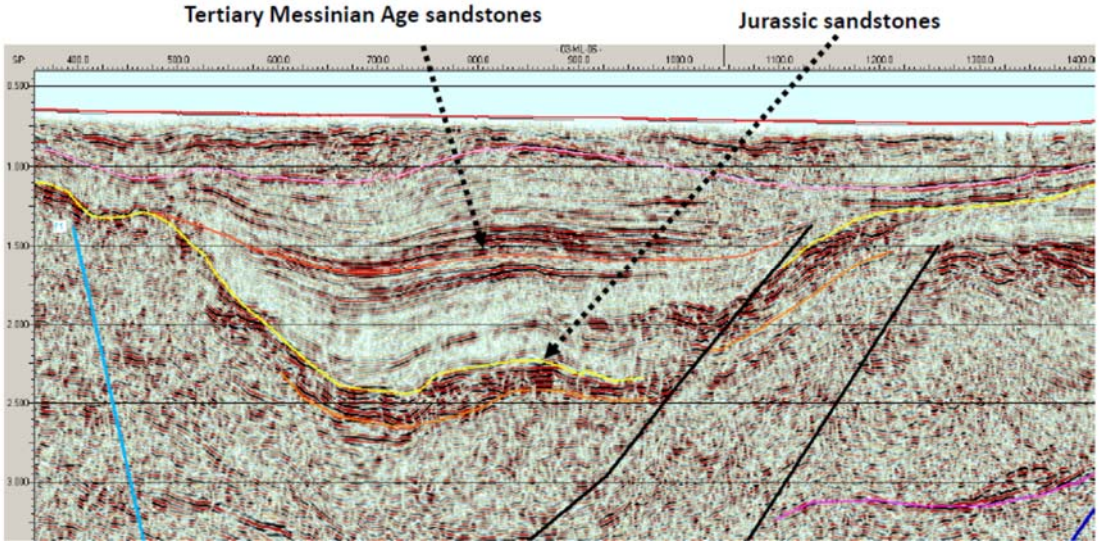


Figure 9 Time structure map top of amplitude anomaly in Miocene. Line 03ML006 is shown on Figure 10.

Reservoir:

The GRF-1 well encountered a series of thin porous sands (1m to 3m thick) in the interval 1,470m – 1,610m overlain by a thick gypsiferous mudstone seal. GRF-1 also has bands of conglomerate in the basal Neogene, but these appear to be less porous and may be very localised in extent. The MSD-1 well also encountered a series of thin sands and silts overlain by a more shaly sequence. KDH-1 encountered 100m gross of interbedded sands in the basal sequence, overlain by silts and mudstones. Outcrop data from the basin shows the younger non-conglomeratic sands from the marine sequence are the best reservoirs.

Figure 10 Seismic Line 03ML-06 showing amplitude anomalies within the Neogene sequence. See Figure 9 for time structure map and location.



DHIs

A number of strong discontinuous seismic reflectors are seen well above the base of the Neogene. In some cases these could be andesite lavas as seen in GRF-1. Other examples such as the 52km^2 closure mapped near the well MSD-1 (see Figure 7) are more convincing, with clear amplitude anomalies on 2003 vintage seismic data (see line 03ML06 – Figure 10).

Volumetrically the Neogene sediments in the Guercif basin are adequate to source large volumes of biogenic gas. While the Gharb basin on the Atlantic coast is somewhat larger, the volume of Neogene sediments in the Guercif basin is not too dissimilar. The success of the biogenic gas play in Gharb suggests that a similar play in Guercif basin is realistic. There is also the possibility of some thermogenic gas sourcing from the underlying Jurassic sequence. Geochemical analyses indicate thermogenic gas reaching the surface in areas of thick Neogene sediments suggesting that salt diapirism and recent Rif tectonics have resulted in some seepage to the surface. This confirms an active hydrocarbon generating system in the area.

JURASSIC

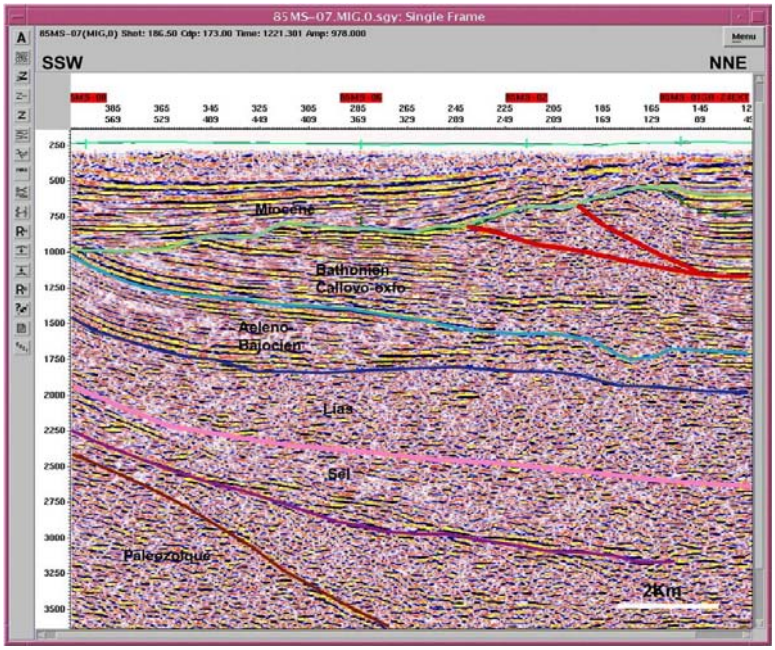


Figure 11 Seismic Line 85MS-07 (PSTM processing) showing Jurassic pinch-out and potential sub-salt Triassic section (ONHYM 2004)

Nearly all Jurassic closures are fault dependent and the large unconformity between upper Jurassic and base Neogene increases the risk of fault leakage as the area has undergone significant structural movement in Miocene to Quaternary time. These movements are associated with the Rif front to the north and northwest. A good geological model of Jurassic depositional environments and the location of key growth faults where there is a marked thickening of the Jurassic (especially lower Jurassic) is the key to successful exploration. Reefal features and oolite banks can be predicted from outcrop geology and seismic interpretation. It can be argued that TAF-1X is the only well drilled to date that targeted the right Jurassic sequence and this missed the target.

A number of seismic lines show Jurassic stratigraphic and structural prospects. ONHYM has mapped a number of Jurassic leads ranging from 18 MMBOE to 366 MMBOE mid case recoverable volumes (Figure 12). It is thought that the most prospective Jurassic reservoirs may be the carbonates rather than the sandstone intervals that tend to have lower porosities and permeabilities. Both carbonate and sand prospects rely on a combination of fracture and secondary porosity.

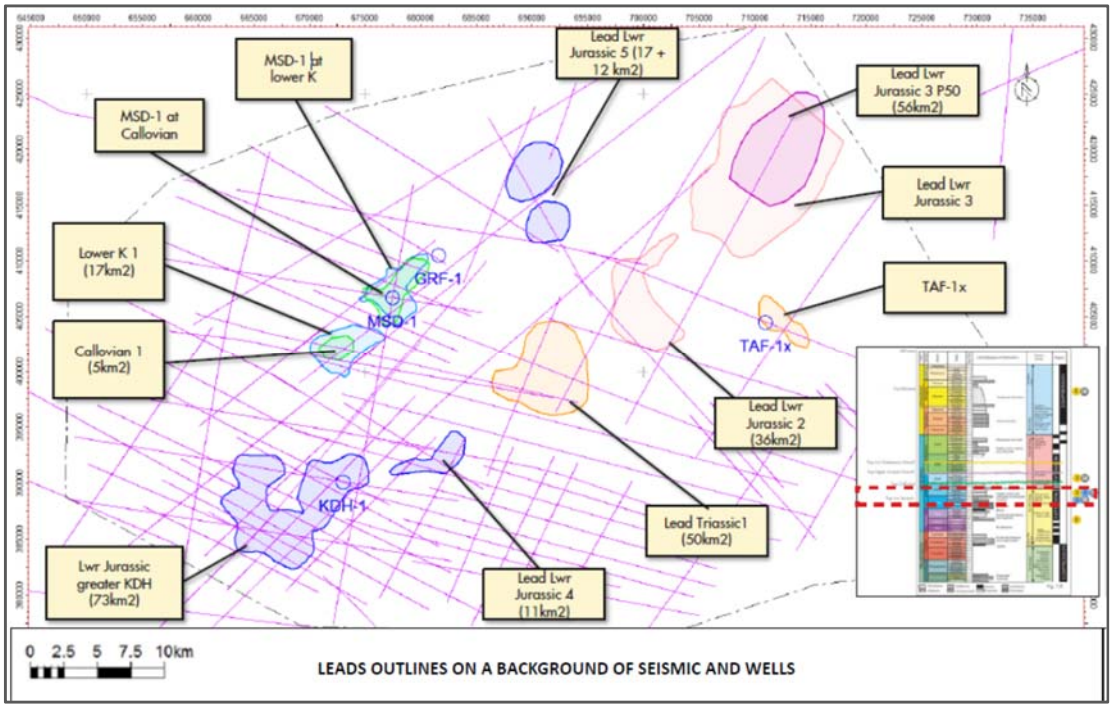


Figure 12 Triassic and Jurassic Leads in the Guercif Basin identified by ONHYM

In the Essaouira basin area, recoverable reserves range from 0.2MM bbls to 7.3MM bbls in the known Jurassic oilfields and from 0.7BCF to perhaps 42BCF (Meskala) for gas. Lias sands have porosities of 16.7% at 2,600m and dolomites porosities of 12% and permeabilities of 8.7md at 2,700m

The GRF-1 well has a possible 39 metres of missed pay in Kimmeridgian limestones from 1,850m to 1,960m; close to TD of the well. The well MSD-1 may also have missed pay in a series of Oxfordian sands between 1,512m and 1,637m, but it is thought that this horizon was tested in the 2008/9 re-entry by TransAtlantic Petroleum. Data on this re-entry was not seen by the authors and not provided by ONHYM.

TRIASSIC

Late Triassic/early Jurassic age salt is known from parts of the Guercif basin and forms significant salt diapirs. Seismic character suggests a locally preserved pre-salt Triassic sequence which may include the TAGI sands seen elsewhere in Morocco and Algeria. Only one well, TAF-1 (for location see Figure 6), has penetrated to basement and this well failed to encounter Triassic reservoir rocks. The presence of excellent salt cap rocks also open possibilities of other sub-salt plays such as fractured or weather Palaeozoic or Pre-Cambrian reservoirs that are proven commercial elsewhere in North Africa.

ONHYM has identified several sub-salt Triassic prospects. One of these prospects has been mapped with a closure of 38km^2 and is well covered by seismic of reasonable quality (Figure 13). Closure appears to be in excess of 150msecs TWT and is shown by seismic line GR-11 EXT (Figure 14).

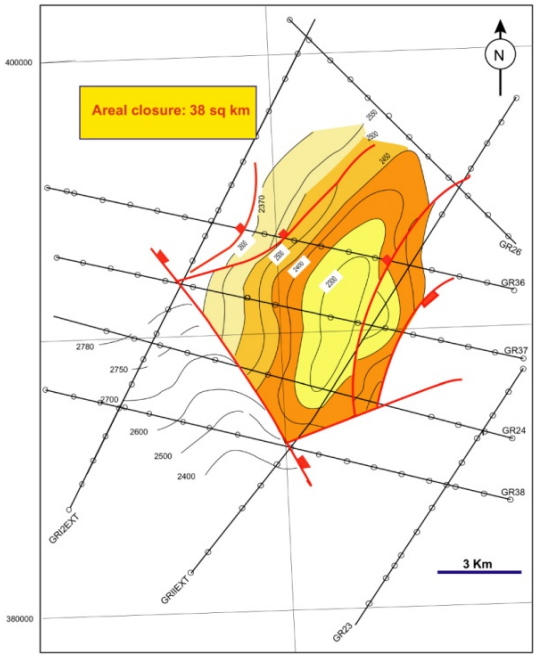


Figure 13 Time structure map of sub-salt prospect in Guercif basin (ONHYM 2004). Seismic Line GR11-EXT is shown on Figure 11.

Most Triassic prospects lie in the area to the east and southeast of Guercif town and could be potentially tested in combination with the Jurassic which is well developed in this area.

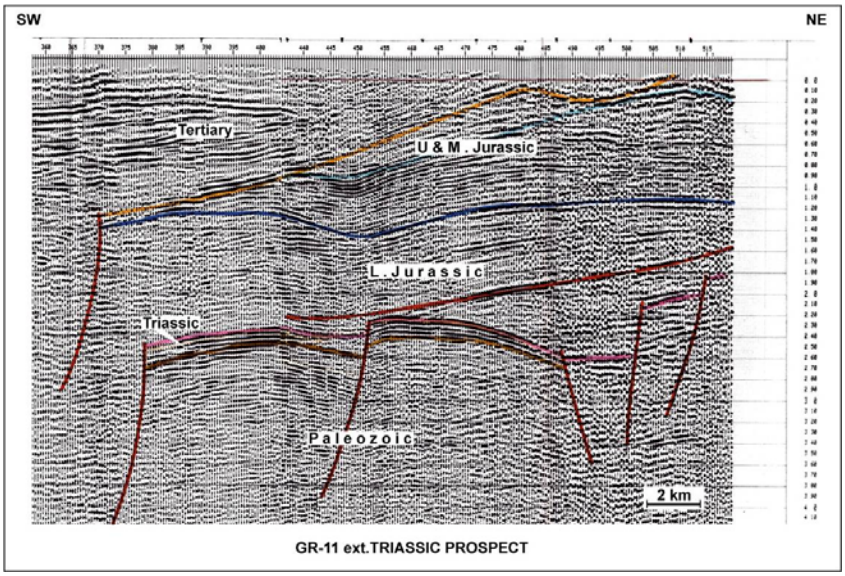


Figure 14 Seismic Line GR-11 EXT illustrates a sub-salt Triassic play (ONHYM 2004)

In the Essaouira basin wells drilled to below 4,000m show Triassic TAGI sand porosities of around 12% (JRP-1 well). In a series of traps mapped historically by LASMO, closures range from 8km^2 to 72km^2 and 25m and 40m as their minimum and maximum likely net reservoir pay. Depths range from 2,200m to 5,000m. They calculate an average reserve per structure at 345BCF. In Meskala wells,

average Trias sand porosity is 10.3 to 13% and permeability 0.6 to 2.5md. Net sand ranges 8m to 24m. Similar reservoir properties can be expected in the Guercif area.

Conclusion

Guercif can be compared geologically with the Gharb basin and its series of commercial biogenic gas discoveries. An oil discovery would benefit from the presence of good road and rail connections to both the Atlantic and Mediterranean coast. A new 150MW wind power plant is under construction in the adjacent Taza area. This would upgrade the local high power electricity grid and permit local gas-powered electricity generation.

In Summary:

a. Reservoirs are postulated in the Triassic (the famous TAGI sands of Algeria), lower middle and upper Jurassic limestones (mainly fracture porosity), middle and upper Jurassic sands and Miocene sands. Only the Miocene sand quality can be considered proven.

b. Predator's stated philosophy is to initially pursue the Neogene (Miocene) sand play.

c. The Guercif basin biogenic gas play is analogous to the Gharb basin on the Atlantic coast where Circle Oil and Caithness Petroleum developed a successful biogenic gas play with sales to local industries. An 8" gas pipeline was constructed by Circle Oil to allow for increased production.

d. The Gharb gas discoveries are individually small but a string of small fields and a high success rate (5 of the last 7 wells quoted) makes them economic. Structural closures may be larger in the Guercif Basin where there is less minor faulting.

e. Re-entry of existing wells to test by-passed pay that may contain gas and the drilling of new Neogene sand prospects is a feasible strategy.

f. Early production of gas would assist cash flow. The use of the 48" Maghreb-Europe Gas Pipeline (MEG) to export gas is technically feasible. No capacity, market or technical reasons exist why Predator could not utilise the MEG to commercialise any gas find in the Guercif Permit Area.

g. Alternatives include sale to cement plants (such as at Oujda), other local industries or the use of gas for local electricity generation.

Re-entry:

Based on currently available data (both published and from TransAtlantic) only two wells penetrated the deep Guercif Neogene graben sequence and encountered good Miocene sands. These are GRF-1 and MSD-1.

a. MSD-1 was drilled by ONAREP (now ONHYM) in 1985 and was apparently re-entered by TransAtlantic Petroleum in 2009. No information is available at present on this attempted re-entry, except a statement that *"log operations and tests on potential zones, at the Jurassic level, were carried out by the end of 2008/9. No inflow of hydrocarbons, in the tested levels, was established"* (ONHYM, 2008). It is not known what condition the well was in and whether the failure can be considered a valid test.

b. GRF-1 was drilled by Elf in 1972. It is not known whether this well can be located or what condition it may be in. However, re-entry of a 40 year old well is questionable.

Exploration well:

a. Predator has proposed "an updip appraisal of the untested hydrocarbons in GRF-1" where some 39m of net gas pay are identified on logs. The seismic line through this well shows a number of strong amplitude events that may be gas sands. Postulated reserves are 10 to 200BCF.

b. Another possible prospect is a mid Tertiary amplitude anomaly with 52km^2 closure mapped at the intersection of seismic lines GA-12 and 03-ML-06 with postulated reserves of 300 to 1000BCF.

We consider that there are proven good reservoirs in the Neogene and that apparent biogenic gas DHIs can been seen on reprocessed seismic in the deep Guercif graben area. The proposed re-entry of old wells is highly questionable, even if the log interpretation is considered valid. New exploration wells to properly log and test the prospects are clearly preferable.

7.0 Risks and Resources

The risk factor, or geological chance of success, is based on the probability of presence and maturity of source rock, presence and quality of reservoir and presence and sealing of structures. This is not to be confused with the probability of economic success.

Table 7-1 Prospect Risking

	Source	Maturity	Reservoir	Seal	Structure	Risk Factor
	1.00	1.00	1.00		1.00	1.00
Guercif Tertiary*	0.90	0.85	0.60	positive	0.75	0.34
Guercif Triassic	0.75	0.90	0.50	salt risk	0.52	0.18

There are three petroleum systems in the Guercif basin with reservoirs in sub salt Triassic clastics, Lower Jurassic reef complexes, Middle Jurassic sandstones, and Tertiary clastics (ERICO, 1986). Predator has prioritised the Tertiary biogenic gas plays. These Tertiary Neogene gas plays are commercial in the very similar Gharb basin to the west where good seismic, processed with Kirchhoff PSTM and AVO has resulted in a remarkably high discovery rate.

Predator has mapped the Tertiary Moulouya Prospect based on seismic amplitude anomalies. The best case gas initially in place (GIIP) is calculated as 646 BCF based on an area of closure of 40.5 km^2 mapped near exploration well GRF-1 (Figure 8). The closure is supported by clear seismic amplitude anomalies seen on 2003 vintage data (Figure 9). Typical Tortonian sandstone beds at outcrop are up to 130ft in thickness (Capella, 2017). Eighty feet of net pay is assumed based on GRF-1 log analysis and multiple separate amplitude anomalies adjacent to the GRF-1 well. Average Porosity is assumed to be 19% based on a range from 13 - 25% seen in the GRF-1 well. Average Gas Saturation is assumed to be 65%. Traces of gas are recorded on the GRF-1 mud logs. A gas expansion factor of 150 was used. Depth to top reservoir is about 1,800m. A 66% recovery factor was used. Volumetrically the Neogene sediments in the Guercif basin are adequate to source large volumes of biogenic gas.

The GIIP is considerably higher than the P10 figures of 41.7 BCF gross quoted by Circle Oil for structures discovered by it in the Gharb Basin. The Gharb gas discoveries are individually small but the high drilling success rate (5 of the last 7 wells) resulted in a number of small producing fields making the prospect economic. Furthermore, gravity, magnetic and seismic data indicates that the Guercif Basin it is more likely to contain larger structures than those seen in the Gharb Basin. Stratigraphic traps can be identified by amplitude anomalies in Tertiary turbidite sand lenses in the Guercif Basin permit area.

A sub-salt Triassic prospect with an area of closure of 38 km^2 has also been identified (Figure 13). A net pay of 100 feet is assumed based on the Triassic reservoir thickness in the TT-1 well in the adjacent Missour Basin. The average porosity is 6% based on a range from 1% to 13%. The average gas saturation assumed is 70% and the gas expansion factor is 300 based on an average depth to reservoir of 3,500m.

The Guercif permit area contains prospective resources as defined by PRMS 2018. 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 (Appendix 2). A drilling

programme is required to prove the Tertiary biogenic gas play. The risk factors that could contribute to project failure are the potential lack of good reservoir development and uncertainty about the size of the structural and stratigraphic traps. The gross best estimate is the probable volume of recoverable gas. The net attributable is based on Predator's 75% interest. The risk factor, or geological chance of success, is an assessment of the chance of having reservoir, mature source rock and effective trap present.

Table 7-2 Prospective Resources Guercif Permit

			Gross			Net Attributable			
Gas Prospective Resources BCF	GIIP	Recovery Factor	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Operator
Guercif Tertiary	646	66%	148	426	879	111	320	659	Predator
Guercif Triassic	515	40%	77	206	378	58	155	283	Predator
Total	1161		225	632	1257	169	474	943	

The best estimate prospective resource for Guercif Tertiary is 320 BCF and the high estimate is 659 BCF.

The best estimate prospective resource for Guercif Triassic is 155 BCF and the high estimate is 283 BCF.

The low best and high estimates are based on a combination of volumetric analyses derived from a range of areas of closure mapped near exploration well GRF-1, a range of spill points based on GRF-1 log analysis, and a range of reservoir porosity based on regional and local geology.

The Tertiary Miocene fluvial channel sands and low-seeking basin-centre turbidites are directly analogous to Circle Oil's gas developments in the Gharb Basin to the west. The analogue for the Guercif Triassic prospect is the Meskala Field in the Essaouira Basin.

The decoupling of the gas price from oil price and the wider availability of shale gas could result in a lower average price for gas in Europe. A SDX Energy update (2018 Annual Report) quoted the realised Morocco gas price for 2018 as USD 9.78 per Mscf. This is the only source of gas price information available. Sound Energy PLC announced it received a gas sales proposal from the state-owned Moroccan power firm, the National Office of Electricity and Drinking Water (ONEE). The offer expects "gas pricing from 2022 based on a structure that includes a variable element linked to the Brent oil price along with a fixed element to fully cover transportation costs (capped at US$12.2mln per year)." Based on this a Moroccan Domestic Gas Prices of USD 8 per Mscf (flat, un-escalated) is reasonable. Based on the potential size of the discovery the development of the prospective resource is likely to be commercially viable.

The Guercif Permits, when they are awarded to Predator, will represent an opportunity to develop an onshore gas play similar to SDX Energy's successful Gharb Basin permits where production commenced in 2008.

8.0 Infrastructure

Pipelines and Logistics

The Guercif licence is ideally located in an area through which the Magreb Europe Gas Pipeline (MEG Pipeline) passes.

Figure 15 MEG Pipeline crossing Guercif Permit area

The MEG Pipeline, also known at the Pedro Duran Farell Pipeline, was constructed to export Algerian gas initially to Spain and subsequently also to Portugal. The pipeline transits Morocco for some 518kms from the Algerian border near Oujda to Cap Spartel, on the Mediterranean coast near Tangier, and commenced operation in November 1996.

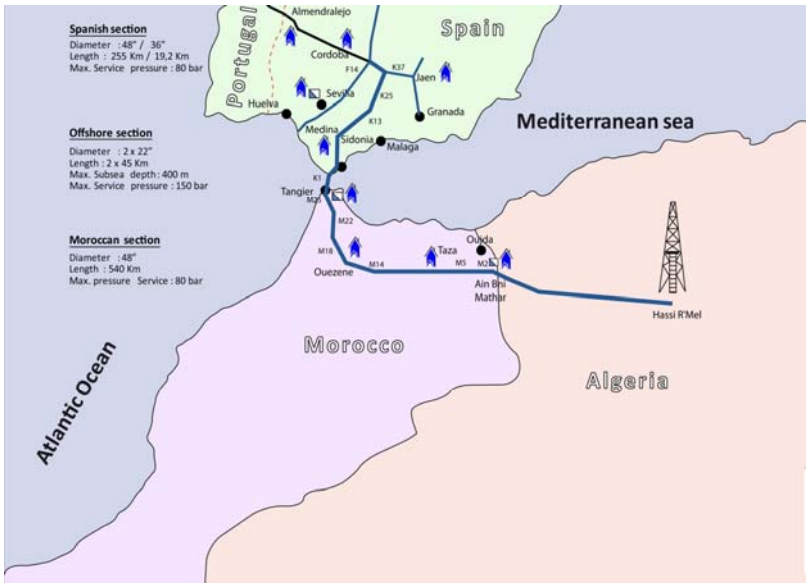


Figure 16 Maghreb-Europe Pipeline

Specification

The Algerian and Moroccan sections of the pipeline are 48" and had an initial design capacity of some 8.6 billion cu meters/year. The maximum operating pressure for the Algerian and Moroccan sections is 80 bar. Originally, compressor stations were located on the Algerian border with Morocco and at Cap Spartel. Capacity was increased in 2004 by adding the Mécheria Compression Station (SC3) in Algeria. This is understood to have increased capacity from 9 to 12 million cu metres per year. Maintenance Centres in Morocco are located at Cap Spartel, Ouezzane, at the Algerian border near Âïn Béni Mathar and at Taza. Taza is located on the western edge of Predator's Guercif Permit.

Moroccan Interest

The Moroccan sector of the MEG pipeline is owned by the Moroccan government and operated by Metragaz, a joint venture of Sagane (owned by the Spanish company Gas Natural, Transgas (Portugal) and Société Nationale des Produits Pétroliers (SNPP) and EMPL). EMPL was responsible for the construction of the pipeline and owns the capacity rights from the Morocco-Algerian border to the Spanish coast until 2020. Metragaz is responsible for the operation and maintenance of the pipeline and receives commissions for transported volume. Metragaz pays royalties to the Moroccan government

Under the original agreement that led to the construction of the pipeline, Morocco receives a 7% royalty on all gas transported through the pipeline. This gas can be taken in cash or kind. Initially it sold its royalty gas to Spanish offtakers. Subsequently, it began to use some of its royalty gas to supply the 385MW Tahaddart power station near Tangier which commenced operation in 2005 and it was anticipated that when the 470MW Âïn Béni Mather power station came on stream in 2010, all of Morocco's royalty gas would be needed to supply these two plants. However, it was reported in August 2011, that Sonatrach had agreed to supply the Office National de l'Electricité (ONE) with 640 million cu meters per year for 10 years for these two power plants. It is not known how this contract impacts on royalty gas.

Although no final agreement has been reported, it is expected that Morocco will assume full ownership of the MEG Pipeline in 2021. This should facilitate access to the pipeline by Predator for any gas discovered in its permit area.

Access to MEG Pipeline

Connection to the MEG pipeline could be made through an existing tee, if these were installed on the line when it was constructed, or at an existing valve or connection point used for maintenance or as a pig trap. Alternatively, the technology exists to undertake a hot tap into the line, which would allow a new pipeline to be connected to the existing pipeline without reducing or halting gas throughput.

There would appear to be no capacity, market or technical reasons why an operator could not utilise MEG to commercialise any gas found in the Guercif permit area. As the pipeline only transports Algerian gas and there are no third parties using MEG to transport gas at this time, it is unclear what access and tariff arrangements would apply. These would need to be negotiated with Metragaz and EMPL, or whatever Moroccan entity takes over full ownership and operation of the pipeline in 2021.

Other Algerian Pipelines

As well as the MEG Pipeline, Algeria has been exporting natural gas to Italy through the Enrico Mattei Gasline (originally known as the Trans Mediterranean Pipeline) since 1983. Another pipeline has been constructed recently by Algeria. Medigaz, which connects directly to Spain without transiting Morocco, commenced operation in March 2011. Galsi, which would connect to Italy through Sardinia, was originally expected to start up in 2014, but has been subject to a number of delays and construction does not appear to have commenced yet. These actual and proposed pipelines could result in reduced supplies through MEG and thus lower the value of the royalty gas that Morocco currently receives from Algeria.

It is understood that export volumes through the MEG Pipeline from Algeria to Europe via Spain have fallen as more gas has been routed through these other pipelines that connect Algeria with Spain and Italy. This could create ullage in the pipeline, that would be beneficial to Predator.

Electricity in Morocco

General

Morocco has power generating capacity of about 8,000MW (end 2015), of which about two thirds is thermal (mainly coal and natural gas), most of which is controlled by the state power utility, Office National de l'Electricité (ONE). However, this capacity is unable to meet growing electricity demand and the Moroccan transmission network is connected with Algeria by a 1,300MW interconnector and with Spain by two 30km subsea transmission cables with a total capacity of 1,300MW. Currently, electricity flows from Spain to Morocco, but Morocco has ambitious plans to increase generating capacity, including exporting solar power to Europe. As part of this, a project to increase transmission capacity is underway to raise this to 2,100MW.

Although ONE retains a monopoly on electricity transmission and distribution, independent contractors have been able to build and operate power stations since 1994. For example, the Tahaddart power station was constructed by ONE (48%), Siemens of Germany (20%) and the Spanish company Endesa (32%) and the Al Wahda power station, which is a joint venture between ONE and Endesa. The location of these plants was chosen because their proximity to both MEG pipeline and the transmission link to Spain.

Options

ONE is encouraging other private operators to build and operate new power stations to satisfy domestic demand and has plans to construct a number of new generating stations on the coast and adjacent to the MEG Pipeline. A third plant close to MEG is planned for Oued Al Makhazine (2x400MW). Thus any gas production from the Guercif Permit could be moved to these stations if commercial agreement could be reached.

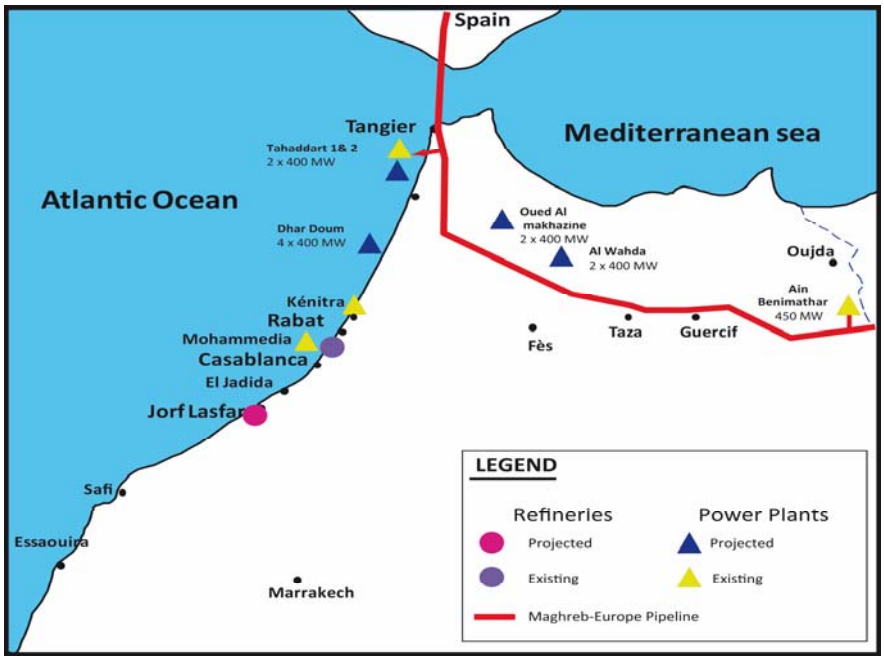


Figure 17 Location of existing and potential gas users (ONHYM)

Another option for utilising gas production in the Guercif Permit could be to generate electricity at the production site and export it to the local transmission or distribution network. As noted above, private companies are permitted to generate electricity in Morocco, but ONE has the monopoly right to sell it. As can be seen below, there is a variety of different voltage transmission and distribution lines already in the Guercif permit area.

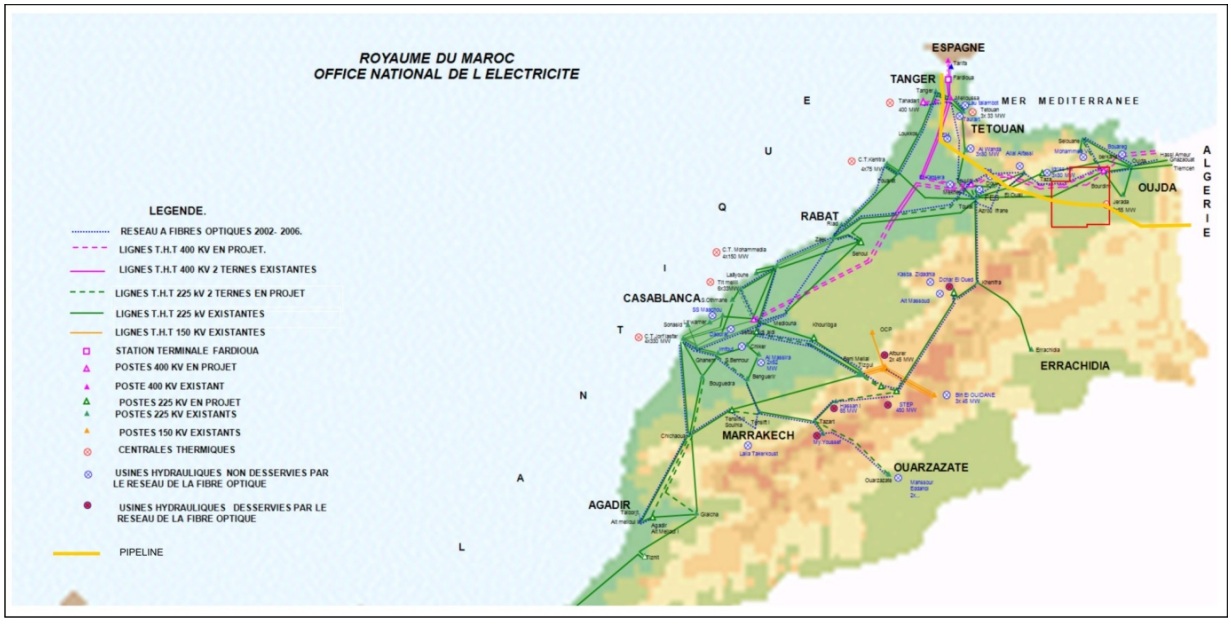


Figure 18 Transmission and distribution lines crossing Guercif Permit (ONE)

If it proved simple and more cost effective to utilise gas for direct power generation on site and export it by wire, this might be a useful bargaining lever in any negotiation for access to the MEG Pipeline.

9.0 Special Factors

9.1 Country Overview

9.1.1 Country Background

Morocco is a constitutional monarchy under King Mohammed VI, who has reigned since 1999. With the advent of the so-called "Arab Spring" a new constitution was passed by popular referendum in July 2011 and new powers have been extended to parliament, although ultimate authority still rests with the monarchy. Parliamentary elections were held in November 2011 and a moderate Islamist party, the Justice and Development Party (PJD) won the largest number of seats. The PJD again won the largest number of seats in the next national election, held in 2016

Moroccan GNP grew relatively rapidly during the last two decades, but this has moderated more recently. The major contributors to GNP include agriculture, phosphate minerals, and tourism, all of which have cyclical elements, particularly rainfall which impacts significantly on agricultural production. However, Morocco, like many other developing countries has seen a significant increase in its population, which has tripled since 1960 (World Bank). Social tensions continue to exist in less developed areas, but overall these are expected to be managed. GDP is forecast to expand by 4% per year in 2019-23, but the economy remains exposed to swings in agricultural output (The Economist).

9.1.2 Energy Background in the context of Natural Gas

Total primary energy consumption in Morocco has been growing at around 5% per annum in recent years. About one third of this is accounted for by electricity generation. In 2015, this was fuelled roughly by coal (31%), natural gas (25%), oil (10%), hydro (22%) and wind (10%) (US Gov). The government is making a sustained attempt to increase the amount of electricity from renewable energy, in particular solar power for both domestic consumption and for export. However, the country is also attempting to increase gas fired electricity generation and has plans to construct an LNG import terminal on the coast at Jorf Lasfar.

Thus, with natural gas production of 94 million m^3 and consumption of 1.480 million m^3 in 2015 (CIA), Morocco is very dependent on gas imports.

As part of the overall energy strategy to reduce rapidly growing level of natural gas imports, Morocco has introduced incentives for foreign companies to encourage investment into the exploration for and production of hydrocarbons. The principal fiscal terms are understood to be:

- The ONHYM royalty for gas is 5% for onshore, with the first 300 million M^3 from each exploitation concession exempted
- The ONHYM royalty for oil is 10% for onshore, with the first 300,000 tons from each exploitation concession exempted
- A 10 year tax free period, before Corporation Tax of 31% is applied
- Oil and gas prices linked to international prices

- ONHYM has carried interest of 25% during the exploration phase but will pay its full share of development and future other costs.

These terms would appear to be attractive, when compared with other North African oil and gas producing countries. A number of other companies are exploring actively onshore Morocco and recently gas discoveries have been announced by SDX Energy at its Lalla Mimouna permit and Sound Energy at Tendrara.

Appendix 1

Data and References

LIST OF FILES PROVIDED BY PREDATOR TO SLR CONSULTING ON MOROCCO ACREAGE

Guercif

Guercif TCM Presentation 4th September 2019

Predator Guercif Presentation 19_11-2018.pdf – presentation on the prospect

Guercif P50 GIIP Tortonian Moulouya Prospect ck23_11_2018.xls – spreadsheet scoping economics Moulouya Tortonian Turbidite Prospect

txt2004.doc – 54 page 2004 report in French on Geology of Guercif area – includes chapters on Upper Jurassic lithostratigraphy, Neogene biostratigraphy, seismo-stratigraphy and structural evolution, geochemistry, log analysis, petroleum potential, prospects & leads, conclusions & recommendations.

préambule04.doc – 1 page introduction in French to above report.

pages chapitres.doc – chapter headings in French to above report.

Tab-fig2004final.doc – List of tables, figures, maps and photos – presumably from above 2004 report (French)

figures et tabeaux rapport guercif 2004 – folder containing all 36 report figures, maps, plates, etc in various formats (PowerPoint, Word, Excel, Adobe Illustrator, JPEG) - *figures rapport Guercif 2004.ppt* is particularly good.

titreguercif2004.doc – title page to 2004 report (French)

étiquete.ppt – Cover of report on Petroleum Potential of Guercif region, December 2004

Bibliogr04.doc – 5 page 2004 bibliography of publications on Morocco – nearly all in French

donneesTerrain04.doc – 6 page 2004 geochemical report based on field samples (French)

Texte rapport Guercif 14-01-05.doc – 50 page 2005 report in French on Guercif region – similar to large report above – possibly a revision.

sommaire 14-01-05.doc – List of Contents of above 2005 report (French)

TRIASSIC-JURASSIC EXTENSIONAL I.pdf – Memoir of the Moroccan Geological Survey on the Triassic-Jurassic extensional system and their reactivation in the Neogene in Northern Morocco, 2002, 136 pages – very detailed with lots of old seismic (English)

Essaouira Basin MESKALA FIELD.doc – 7 page report on Essaouira Basin giving oil and gas reserves by field for 2001 plus details on Meskala gas field (English)

TML_Morocco_Guercif_Brochure Feb2007.pdf – Transatlantic Petroleum Corp 4 page Farmout brochure dated February 2007 for Guercif / Beni Znassen Reconnaissance License (English)

Moroccan Natural Gas Sector V finale.pptx – ONHYM PowerPoint presentation September 2009, 23 slides (English)

Circle Oil Jan 2011 v3 22-01-11.pdf – 31 page PowerPoint presentation by Circle Oil Plc dated January 2011 – includes sections on Morocco, Tunisia, Egypt, Oman. Section on Morocco covers Rharb Basin - Sebou & Oulad N'zala Permits (English)

Guercif_Présentation_Pathfinder_06_05_2011 NEW.ppt – Petroleum Evaluation of the Guercif Basin – 91 slides, lots of good detail. Not sure who wrote it or when (English)

Guercif Block Corporate Presentation 02 Aug 2011.ppt – 22 page Pathfinder presentation on onshore shallow gas opportunity with geology, seismic, economics, budgets (English)

Morocco_Flyer_August_2011.pdf - Transatlantic Petroleum Corp 8 page Farmout brochure dated August 2011 for the under-explored Asilah Exploration Permit and the Tselfat Exploration Permit (which includes Haricha oil field redevelopment) (English)

FB.pdf – Maghreb Petroleum Exploration SA – 61 page Farmout brochure dated October 2011 – Tendrara, Tendrara-Sud & Missour-Est onshore blocks and Casablanca-Safi & Loukos blocks offshore (English)

Guercif Block Corporate Presentation 02 NOV 11.ppt – 25 page Pathfinder presentation on onshore shallow gas opportunity with geology, seismic, economics, budgets (English) – update on August presentation above.

Guercif presentation nov2011.ppt – very slightly modified version of above Pathfinder presentation – 25 slides dated 3rd November 2011

NW_Africa_Davison.pdf – paper by Ian Davison on the Central Atlantic margin basins of North West Africa: Geology and hydrocarbon potential (Morocco to Guinea), Journal African Earth Sciences 2005, 21 pages (English)

PHVL New Proposal GUERCIF APPLICATION 18102011.doc – PHVL Application letter for Guercif Onshore Block dated 4th October 2011 (English)

Guercif Onshore.jpg – map of Guercif Permits with coordinates

Guercif_Geologie.jpg – geological map of region with Guercif Permits area outlined.

Guercif budget 01 Nov 2011 (Fast-tracked Drilling).xls – spreadsheet as stated in title

Guercif budget 01 Nov 2011 (Minimum Commitment).xls - spreadsheet as stated in title

Guercif budget 21 Nov 2011 Two Wells 2012.xls - spreadsheet as stated in title

Guercif P90 Miocene Gas Economics 21112011.xls – spreadsheet as stated in title

Guercif P90 Miocene Gas Economics 21 11 2011 with NPV.xls - spreadsheet as stated in title

Guercif P50 Trias Prospect A Gas Economics 12122011.xlsx - spreadsheet as stated in title

Guercif P50 Tortonian Prospect A Gas Economics 12122011.xls – spreadsheet as stated in title

1. Others

Pathfinder corporate presentation Morocco 2 11 11 Part A.ppt – PowerPoint presentation dated 11th November 2011 on both Foum Assaka and Guercif Permitss – 16 slides in Part A with Parts B & C below having further slides (English)

PART B.ppt – Further 12 slides on Foum Assaka as above, including comparison with other West African plays

PART C.ppt – 25 slide Guercif presentation –as earlier version above?

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Appendix 2

Petroleum Reserve Definitions

This Glossary provides high-level definitions of terms used in reserves evaluations by the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).

DEFINITIONS

Reserves are those quantities of petroleum[1] which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

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

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

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

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

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

PROVED RESERVES

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

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

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

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

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

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

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

UNPROVED RESERVES

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

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

PROBABLE RESERVES

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

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when(a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favourable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behaviour in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

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

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

RESERVE STATUS CATEGORIES

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

Developed: Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary

equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

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

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

Behind-pipe reserves are expected to be recovered from zones in existing wells, which will required additional completion work or future recompletion prior to the start of production.

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

The following Glossary provides high-level definitions of terms used in resources evaluations by the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).

As with unproved (i.e. probable and possible) reserves, the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of quantities classified as resources. Such disclosure is left to the discretion of the countries or companies involved. Estimates derived under these definitions rely on the integrity, skill, and judgement of the evaluator and are affected by the geological complexity, stage of exploration or development, degree of depletion of the reservoirs, and amount of available data. Use of the definitions should sharpen the distinction between various classifications and provide more consistent resources reporting.

DEFINITIONS

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

TOTAL PETROLEUM-INITIALLY-IN-PLACE

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

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

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

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

RESERVES

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

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

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

CONTINGENT RESOURCES

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

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

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

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

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

PROSPECTIVE RESOURCES

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

ESTIMATED ULTIMATE RECOVERY

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

AGGREGATION

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

RANGE OF UNCERTAINTY

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

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

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

RESOURCES CLASSIFICATION SYSTEM

Graphical Representation

Figure 2.1 is a graphical representation of the definitions from the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to

classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

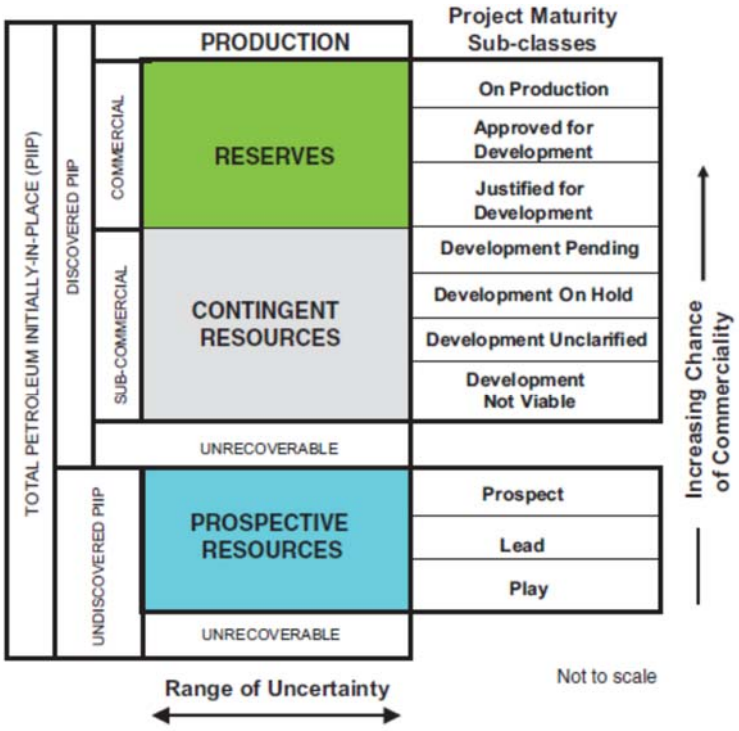

Figure 2.1—Sub-classes based on project maturity

As indicated in Figure 2.1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

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

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

Appendix A Glossary and Definitions of any terms used

AIM	Alternative Investment Market
AVO	In geophysics, amplitude versus offset (AVO) or amplitude variation with offset is a variation in seismic reflection amplitude with change in distance between shotpoint and receiver.
B	Billion (10^9)
bbl	Barrels
stb	Stock tank barrels
BCF	Billion cubic feet of gas
Beni Znassen	A Mesozoic geological basin located to the north of the Neogene Guercif basin and extending up to the Mediterranean coast.
bopd	Barrels oil per day
BRPM	Bureau de Recherches et de Participations Minières – state owned company responsible for both oil and mineral exploration in 1950s and 1960s
Bscf	Billion standard cubic feet
CPR	Competent Person's Report
DHIs	Direct Hydrocarbon Indicators as seen on seismic sections. Also known as bright spots or amplitude anomalies.
Ft	feet
ft^3	Cubic feet
GIIP	Gas initially in place
GWC	Gas Water Contact
km	Kilometres
km^2	Square kilometres
m	Metres
m^3	Cubic metres
mD	Permeability in millidarcies
M	Thousand (10^3)
MEG	48" Maghreb-Europe Gas Pipeline that transports gas from Algeria to Spain and Portugal via Morocco.
Middle Atlas	A mountain range formed as a result of the uplift and inversion of the Mesozoic Middle Atlas rift basin. The Neogene Guercif basin is developed over a down-warped part of this trend.
High Atlas	Another mountain range formed as a result of the uplift and inversion of the Mesozoic High Atlas rift basin. This lies to the south of the Middle Atlas and the Guercif basin.
MM	Million (10^6)
MD	Measured Depth
ONAREP	earlier name for the government organisation responsible for both mining and petroleum activities – now ONHYM.
ONHYM	Office National des Hydrocarbures et des Mines – the current government organisation responsible for both mining and petroleum activities. Also a carried partner in the PHVL permits.
PI	Productivity Index
psi	Pounds per square inch
psig	Pounds per square inch gauge

PSTM	Pre-stack time migration – a method of processing seismic data to enhance the data and to move the data into the correct position with regard to faults
Kirchhoff PSTM	A specialised version of PSTM using the Kirchhoff algorithm to enhance data quality.
Rharb	A geological basin located on the Atlantic coast of Morocco that is analogous to the Guercif basin in its development and sedimentary fill. Also known as the Gharb basin.
RF	Recovery Factor
Rif	The Rif is a mainly mountainous region of northern Morocco that is part of the Cordillera Bética that also includes the mountains of Southern Spain. The Rif Mountains are not part of the Atlas Mountains but belong to the Gibraltar Arc or Alborán Sea geological region that formed in Miocene to Recent time as a result of the collision of Spain and Morocco.
scf	Standard Cubic Feet
scfd	Standard Cubic Feet per day
SPE	Society of Petroleum Engineers
SS	Subsea
SW	Water Saturation
Tcf	Trillion cubic feet of gas
TVDSS	True Vertical Depth Subsea
WPC	World Petroleum Congresses
2D	Two dimensional
3D	Three dimensional
%	Percentage

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COMPETENT PERSONS REPORT

PREDATOR OIL AND GAS VENTURES LTD

CORRIB SOUTH LICENSING OPTION 16/26

OFFSHORE IRELAND

SLR Ref: 501.00269.00002
Final
30 January 2020

BASIS OF REPORT

This document may contain information of a specialised and/or highly technical nature and the Client is advised to seek clarification on any elements which may be unclear to it.

Information, advice, recommendations and opinions in this document should only be relied upon in the context of the whole document and any documents referenced explicitly herein and should then only be used within the context of the appointment.

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1.0 Introduction

SLR Consulting (Ireland) Ltd ('SLR') of 7 Dundrum Business Park, Windy Arbour, Dublin 14, Ireland, has been commissioned by Predator Oil and Gas Ventures Limited (the "Company") to complete a Competent Person's Report (the "CPR") on the company's Corrib South Licensing Option 16/26 (net interest 50%) asset.

This CPR has been prepared in accordance with the requirements of paragraphs 131 to 133 of the ESMA update of the CESR recommendations in respect of the consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive to include an independent expert's report (CPR) in a prospectus document. Resources are reported in accordance with The Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018). The deterministic incremental approach was chosen because the Corrib South Licensing Option 16/26 asset is at the pre discovery stage and the full range of reliable values for input parameters to a probabilistic approach are not available.

The CPR has been prepared by Mr Nick O'Neill, with assistance from Mr Richard Vernon, Mr Martin Davies and Mr Charlie Carlisle based on data supplied by the Company, a literature search carried out by SLR and some independent verification. The data comprised details of permits and acreage interests, basic exploration geological and geophysical data, interpreted data, and technical presentations. SLR has exercised due diligence and independent analysis where appropriate on all technical information supplied by the Company. SLR has not independently checked title interests with Government or licence authorities.

Richard Vernon has more than 30 years' experience in the energy sector. After graduating with a business degree majoring in accounting and marketing, he worked as a financial analyst specialising in the Canadian oil and gas sector. He then joined the London based consultancy Petroleum Economics Limited and covered all aspects of the international oil and gas industry, including exploration/production and refining/marketing, taxation and licensing regimes, supply/demand/price strategies and forecasting, etc. for a wide range of clients including governments, international institutions and national and private oil companies. Subsequently, he moved to the US based multinational oil and gas company Phillips Petroleum Company as Director of External Affairs, responsible to the Managing Director of the Europe/Africa Division.

Martin Davies BSc FGS Chart Geol EurGeol PESGB is a Senior Petroleum Geologist. Mr Davies joined SLR in 1993 after 18 years international experience in oil and gas exploration development and production, both onshore and offshore, with British Petroleum. He has worked in Ireland, the UK, North Africa, the Middle East and the Far East. He has also worked on a number of exploration portfolio evaluations for UK and Irish based independent oil companies.

Nick O'Neill BSc MSc PGeo EurGeol MEI PESGB M AAPG is a Senior Petroleum Geologist and Director of SLR Ireland. Mr O'Neill joined SLR in 1994, having worked internationally in oil exploration operations since 1977. He was operations manager in the Middle East for an oilfield service company. He obtained an MSc in Petroleum Geology in 1986. He was operations geologist with BP and Shell in London and Aberdeen responsible for North Sea exploration operations. He has written a number of valuations and CPR reports on hydrocarbon properties in Ireland, the US, West Africa, and Italy for UK and Irish based independent oil companies.

Charlie Carlisle BSc Geol (Hons), MSc. Petroleum Geology, is experienced in seismic interpretation, wireline analysis, and logging of drill core and cuttings. He is familiar with all technical stages of hydrocarbon exploration. He joined SLR in 2013 as a project geologist. He completed his M.Sc. in Petroleum Geology at Dalhousie University in 2017 and after a short period working with the Petroleum Affairs Division in Dublin he has re-joined SLR to provide geological assessments and exploration risking.

SLR Consulting (Ireland) Ltd. has many years of experience undertaking independent expert studies and has completed Expert Reports and Valuations for listings on the London, Copenhagen, Dublin, Vancouver, Luxembourg and Australian Stock Exchanges.

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

INDEPENDENCE OF SLR

This competent persons' report has been prepared by Nick O'Neill who is professionally qualified and a member in good standing of the Institute of Geologists of Ireland, an institution relevant to the activity being undertaken, and who is subject to the enforceable rules of conduct. Nick has at least five years' relevant professional experience in the estimation, assessment and evaluation of oil and gas projects. Nick is independent of Predator Oil and Gas Ventures Limited, its directors, senior management and its other advisers; has no economic or beneficial interest (present or contingent) in the company or in any of the oil and gas assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

SLR confirms that, based on the information provided to it and to the best of its knowledge, there has been no material change in circumstances to those stated in the CPR and in this letter.

We confirm that SLR is responsible for this letter and the contents of the CPR and we declare that we have taken all reasonable care to ensure that the information contained in this letter and the CPR is in accordance with the facts and there is no omission likely to affect its import.

Yours faithfully,

Mr. Nick O'Neill

Director

SLR Consulting (Ireland) Ltd.

2.0 Legal Overview

On 3rd June 2016 the then Minister for Communications, Energy and Natural Resources reserved by way of Licensing Option 16/26 an area amounting to 302.4861 km^2 over blocks 18/24(p), 18/25(p), 18/29(p) and 18/30(p) within co-ordinates 54°20'0'' N, 11°18'0'' W, 54°7'30'' N, 11°18'0'' W, 54°7'30'' N, 11°6'0'' W, 54°20'0'' N, 11°6'0'' W, 54°20'0'' N, 11°18'0'' W for Predator Oil and Gas Ventures Limited (50% and Operator) and Theseus Limited (50%) from 1st July 2016 to 30th June 2018 subject to the following conditions:

1. During the option period Predator Oil and Gas Ventures Limited will carry out an agreed programme of work as defined below.
2. Predator Oil and Gas Ventures Limited will prepare and present reports to the Department on the results of the work undertaken as specified by the Department in their reporting requirements
3. Predator Oil and Gas Ventures Limited will hold a Petroleum Prospecting Licence (PPL) during the full period of the Licensing Option.
4. Predator Oil and Gas Ventures Limited will pay annual rental fees applicable in respect of the Licensing Option area.
5. On or before 30th June 2018 Predator Oil and Gas Ventures Limited will relinquish the Licensing Option or will have applied to have the acreage covered by the Licensing Option exclusively licensed.
6. If Predator Oil and Gas Ventures Limited applies, on or before the expiry date of the Licensing Option, to licence the area reserved by Licence Option 16/26 the Minister will be prepared to consider the granting of a Frontier Exploration Licence to the company covering an area to be agreed with the Minister having regard to the work programme proposed by Predator Oil and Gas Ventures Limited.
7. Predator Oil and Gas Ventures Limited must demonstrate to the Minister's satisfaction that it has the technical and financial resources for a Frontier Exploration Licence before such a follow on authorisation will be granted.
8. Predator Oil and Gas Ventures Limited complies with the General provisions and provisions relating to Licensing Options as set out in the Licensing Terms for Offshore Oil and Gas Exploration and Development 2007.

The agreed programme of work to be completed during the period of Licensing Option 16/26 is:

1. Purchase of all released seismic, well and other technical data relevant to the Licencing Option area.
2. Perform petrophysical analysis and integrate with existing geological and geophysical data to create a consistent interpretation over the Licensing Option area. Re-interpret the integrity of structures drilled and the impact of results on undrilled structures.
3. Reprocess a minimum of 300km of 2D seismic data and in the order of 400km^2 of 3D seismic data.
4. Map leads and prospects.
5. Review and assess the potential of Upper Carboniferous and possible Permian Rotliegendes equivalent structural features, both beneath the mapped Prospects/Leads and elsewhere within the Licensing Option area, and in respect of the mapped Prospects/Leads, review and assess all conduits for the migration of Carboniferous sourced gas through the Zechstein.
6. Incorporate the results of the work programme into a comprehensive assessment of the petroleum potential of the Licensing Option area, including the results of the detailed mapping of the identified Prospects and Leads, of the geological interpretation of each of these features, and of the perceived risks attaching to them and submit the assessment to the Department along with reports on other constituent studies performed as part of the work programme, no later than three months before the expiry of the Licensing Option.

7. Propose, no later than three months prior to the expiry of the Licensing Option, a detailed work programme for any follow-up Frontier Exploration Licence for the approval of the Minister.

The reporting requirements for Licensing Option 16/26 are as follows:

- Before the June 30th 2017 Predator Oil and Gas Ventures Limited will report to the Department on its progress in completing the agreed work programme during the first year of the Licensing Option.
- Before 31st March 2018 Predator Oil and Gas Ventures Limited will prepare and present a report detailing the results of its work to the Department. The report will provide details of Predator Oil and Gas Ventures Limited technical assessment of the Licensing Option area, including:
    - The geology of the Licensing Option area with a full description of structural controls, stratigraphy and plays supported by structure maps, illustrative seismic sections with well ties, correlation panels, facies maps, burial history/maturation models, source kitchen maps, stratigraphic summary charts, etc.
    - An evaluation of each prospect or lead identified with detailed description of trap, reservoirs, source rocks, seals, timing of trap development, timing of hydrocarbon migration, migration route, volumetrics and critical risks supported by time and depth structure maps for key horizons, interpreted dip and strike seismic sections, fault plane profiles, reservoir parameters etc.
    - Full documentation of any technical studies or analyses performed or commissioned pertinent to the Option area.
    - A complete listing of the database used (well data, seismic data, reports/studies purchased or traded) with specific details of all physical and geological data acquired during the period of the Option.

On 7th June 2016 Predator Oil and Gas Ventures Limited and Theseus Limited confirmed acceptance of the terms and conditions of Licensing Option 16/26. As required under the Licensing Option conditions Predator Oil and Gas Ventures Limited holds a Petroleum Prospecting Licence (PPL) valid for the full period of the Licensing Option. On 25th May 2018 Predator Oil and Gas Ventures Limited applied for a Frontier Exploration Licence, a Successor Authorisation to Licensing Option 16/26.

With respect to the agreed work programme Predator Oil and Gas Ventures Limited has re-mapped Corrib South with special attention to depth conversion sensitivities. Quotes have been received for seismic re-processing and work will commence subject to receipt of seismic field tapes from Shell.

3.0 Geological Overview

3.1 Slyne Basin

The Corrib South Prospect is located in the North Slyne Basin, a Mesozoic half-graben, which lies approximately 60km offshore west of Ireland. Water depths are between 200m and 400m. The Slyne Basin is part of the Mesozoic basin system which stretches from the West Shetland Basin, north of Scotland, to the Porcupine Basin, west of Ireland (Corcoran & Dore, 2005). It is a 35km wide eroded graben system which trends NNE for 200km across the Palaeozoic and Precambrian basement rocks of the shelf off northwest Ireland. The graben is deepest in the south. To the north it joins the 150km long Erris Basin (Figure 1). The Slyne Basin has a thin Cretaceous to Quaternary cover above a Jurassic section more than 2,000m thick overlying Triassic and Zechstein strata which rest unconformably on Carboniferous rocks (Figure 2). The basin is controlled by the presence of a number of complex transfer zones which show strike-slip movement and post-Miocene reactivation The basin has been affected by regional uplifts in mid Cretaceous and Oligocene/Miocene times which together amount to 1 to 2km (Scotchman, 1995). There is a proven Lower Jurassic petroleum system in the Slyne Basin (Bandon Oil Discovery 27/4-1,1z) and the commercial Corrib Gas Field in the Triassic Sherwood Sandstone reservoir thought to be sourced by Carboniferous coals.

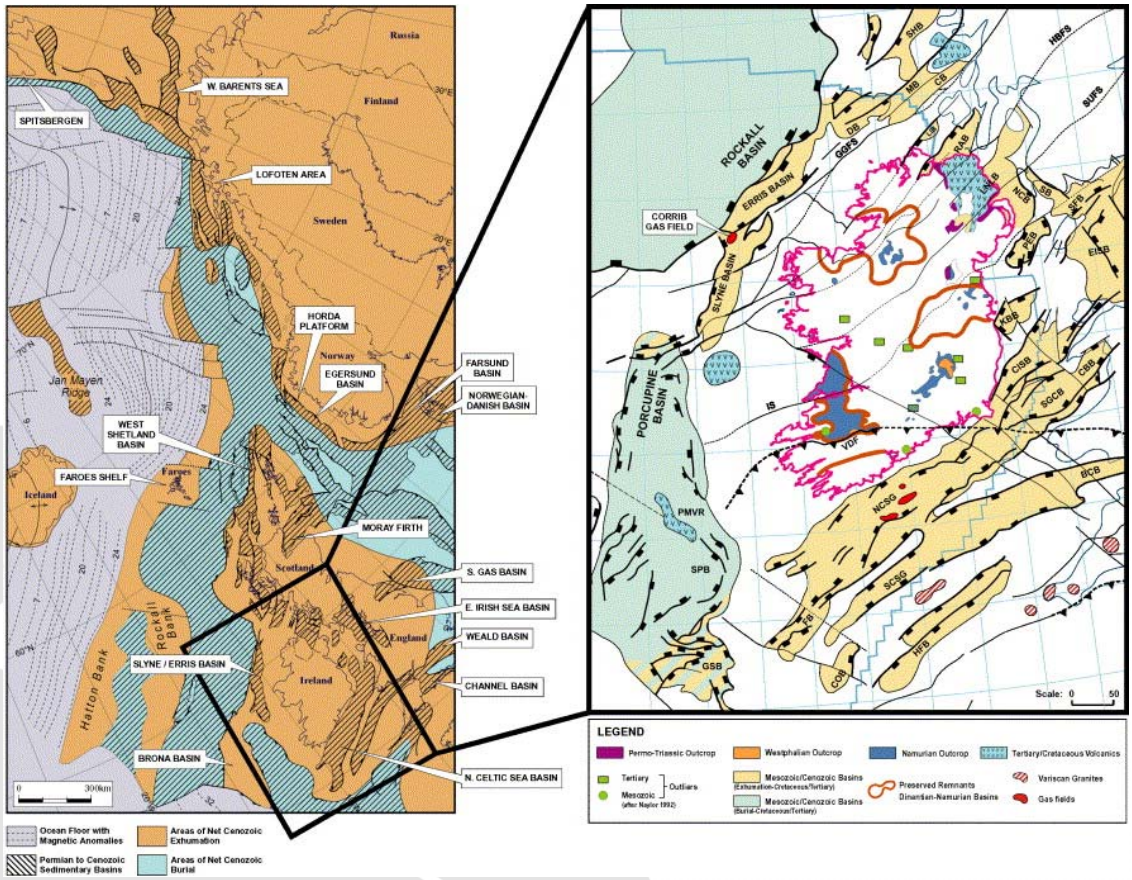
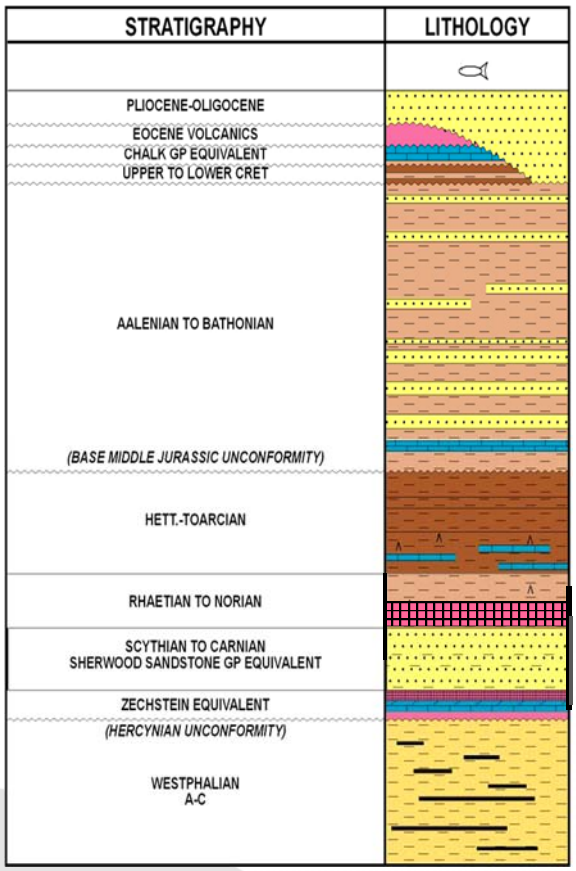


Figure 1 Slyne Basin regional setting (Source Corcoran & Dore, 2005)

Pockmarks at the seafloor and palaeo pockmarks at the Intra-Late Tertiary horizon are identified on multibeam bathymetry, high resolution 3D reflection seismic and sub bottom acoustics in the Slyne Basin which may reflect distinct multiple phases of fluid seepage in the basin. Extensional fault systems that displace the Late Palaeozoic and Mesozoic succession might have facilitated vertical migration of reservoir fluids during the Cenozoic deformation (Roy, et al., 2017).



- Neogene - thin
- Palaeogene - Eocene lavas
- Upper Cretaceous Chalk Group
- Lower Cretaceous - Albian
- **Middle - Upper Jurassic**
  - **Intraformational sealing Shales**
- **Middle Jurassic reservoir**
  - **Bathonian sandstone reservoirs**
- **Lower Jurassic source**
  - **organic rich shales**
  - **Upper Triassic Seal- shales and evaporites**
- **Lower Triassic Reservoir - fluvial clastics**
- **Permian Seal - thick evaporites**
- **Carboniferous Source and ?Reservoir - Westphalian and Namurian fluvio-deltaics**

Figure 2 Slyne Basin Stratigraphy & Play Elements (after Shell)

3.2 Exploration History and Database

Six exploration wells were drilled in the Slyne Basin between 1981 and 1999. One well was drilled by Elf in 1981 and five by Enterprise Oil between 1996 and 1999 resulting in the discovery of the Corrib Gas Field. Enterprise Oil drilled another three appraisal wells in the Corrib area before it was acquired by Shell in 2002. Shell E&P Ireland drilled a number of Corrib production wells and one exploration well 18/20-7 in 2007 for a potential Corrib tie in called the Corrib North Prospect. Well 18/20-7 was plugged and abandoned without shows in the Triassic Sherwood Sandstone. Statoil drilled the Cong Prospect further north of Corrib in 2003 with well 19/11-1a. The well was plugged and abandoned without shows in the Triassic Sherwood Sandstone. Serica drilled well 27/4-1Z into the Jurassic Bandon Prospect in 2009 to the south of Corrib. The well encountered a 38m oil column in Lower Jurassic reservoir sandstones but the secondary Triassic Sherwood Sandstone was of moderate quality and water wet (Figure 3). In July 2017 Canada Pension Plan Investment

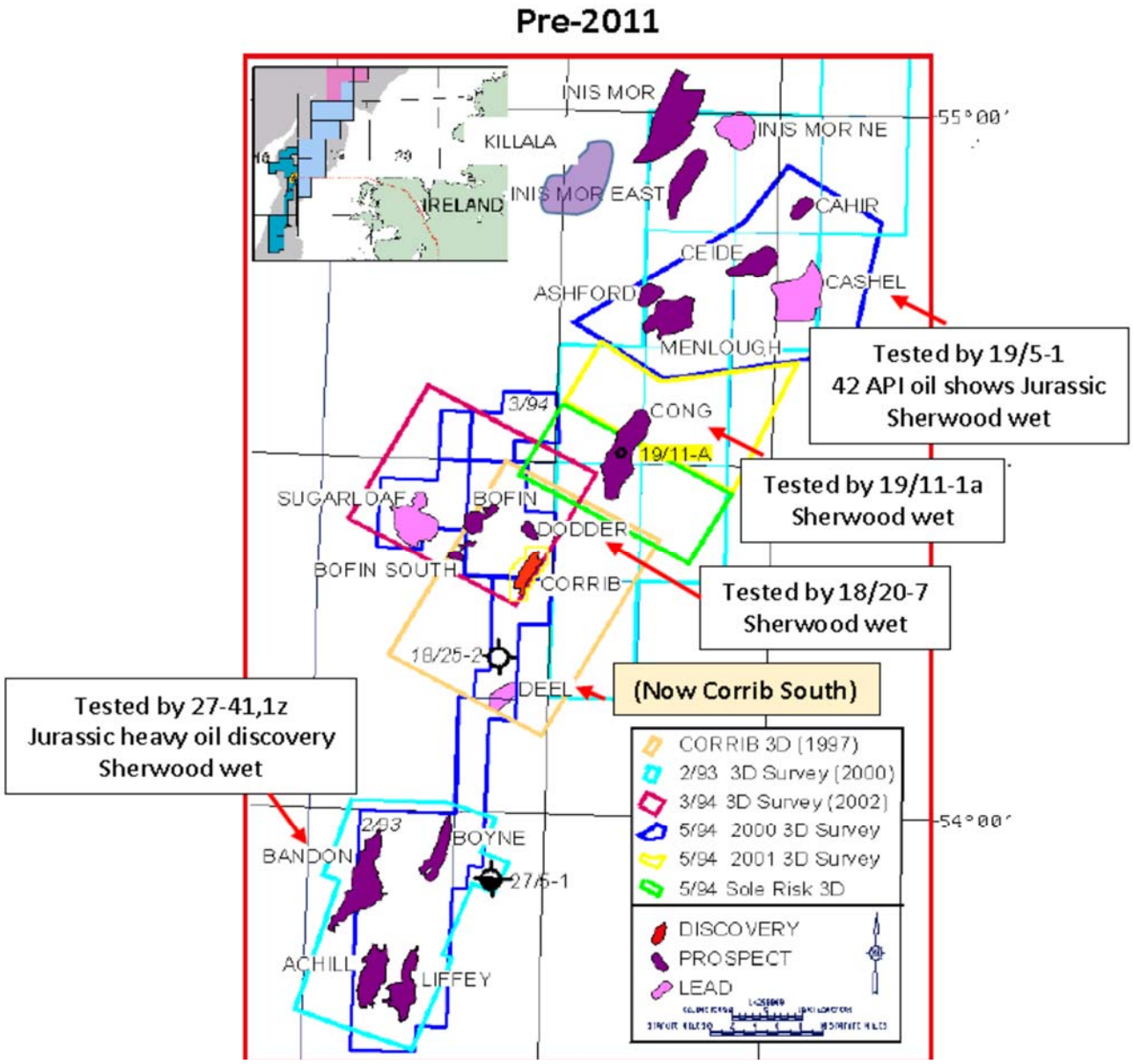


Figure 3 Historic inventory of prospects and leads in the Corrib Area (Source Predator modified after Shell)

Board (CPPIB) and Vermilion Energy Inc. announced a strategic partnership in the Corrib Gas Field whereby CPPIB will acquire Shell's 45% interest in the field with Vermilion operating the assets after completion of the acquisition with closing anticipated in the first half of 2018.

The Slyne Basin has six 3D surveys acquired between 1997 and 2002 and an extensive 2D seismic grid of 20 surveys between 1976 and 2007. The Corrib South Prospect is covered by Enterprise Oils Western Geophysical E97IE 3D seismic survey and an extensive 2D seismic grid (Figure 4).

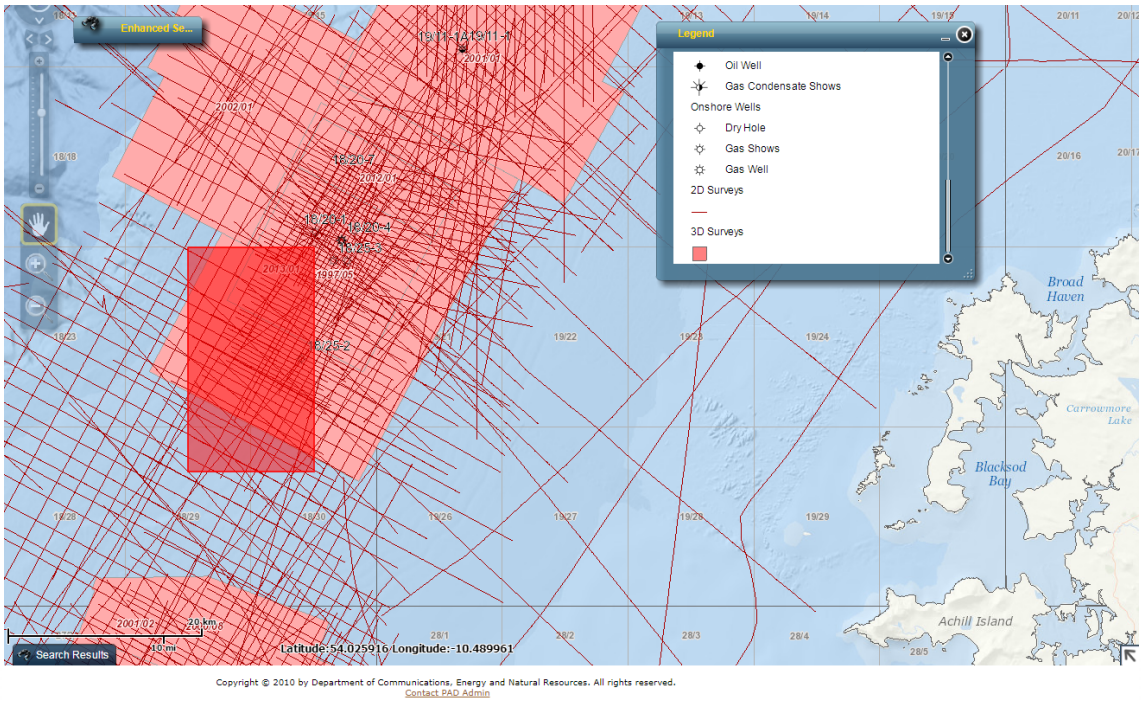


Figure 4 Seismic coverage in the LO16/26 Corrib South Prospect area (Source PAD)

3.3 Corrib South Prospect

Corrib South is an undrilled Triassic Sherwood Sandstone gas prospect in the Northern Slyne Basin first identified by Enterprise Oil as the Deel Prospect. It was retained by Shell under Reserved Area Licence 1/05 following the acquisition of Enterprise Oil and the relinquishment of EL2/93. RA1/05 expired on 31/12/2008. Providence Resources held Licensing Option 11/12 over the prospect until it expired on 31/10/2013. The Jurassic is not seen as a viable exploration target in the area covered by LO16/26 because the traps are too small and have cross-fault sealing risks. Furthermore the presence of light oil sourced from an optimally mature Jurassic source interval cannot be demonstrated within the area adjacent to LO16/26. There may be potential for the development of Permian Rotliegendes reservoir sands within the licence area. The trend defined by the Midland Valley Basin of Scotland and the Larne Basin of Northern Ireland, where the Permian is well-developed, may also extend into the Slyne Basin.

Enterprise Oil drilled well 18/25-2 in 1999 approximately 60km off the west coast of Ireland on the Shannon structure 8km north of the Deel Prospect. This is the nearest offset well to the Corrib South Prospect. The well was plugged and abandoned as a dry hole having penetrated the primary Lower Triassic Sherwood Sandstone Group target 891m high to prognosis with no hydrocarbon shows detected. Post well log

correlation with well 27/5-1, sedimentology and petrographic analysis has identified this interval as a fine grained basal Sherwood Sandstone interval similar to other local occurrences. The secondary Middle Jurassic sandstones were penetrated close to prognosis but without hydrocarbon shows.

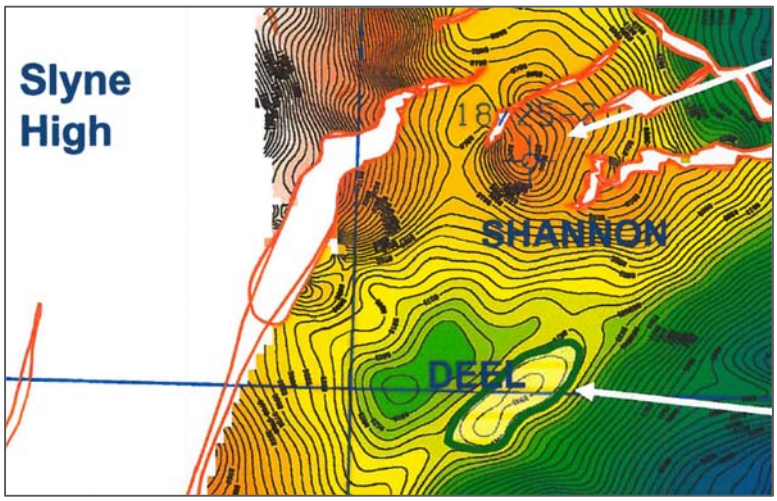


Figure 5 Top Sherwood depth map showing well 18/25-2 on the Shannon structure approximately 8km north of the Deel Prospect (after Enterprise Oil)

In the post well structural analysis the main prospect bounding fault to the west and south had a much greater throw than anticipated. Also seismic evidence suggests that the Sherwood Sandstone interval is thinned below an unconformity within the Lower Jurassic. The Lower Jurassic onlaps this unconformity from the south, suggesting that the structure may have been a topographic feature at the time. The well was drilled close to the crest of the structure at Sherwood Sandstone level where faulting is concentrated, making it difficult to determine if faults or erosion were the main process responsible for thinning the Sherwood Sandstone Group. The well penetrated the lower part of the Sherwood Sandstone Group in the footwall (see Figure 6). The correlation of the Top Triassic seismic reflector from the Corrib Field to the Shannon Structure was erroneous. The well reached total depth in Silurian siltstones and shales.

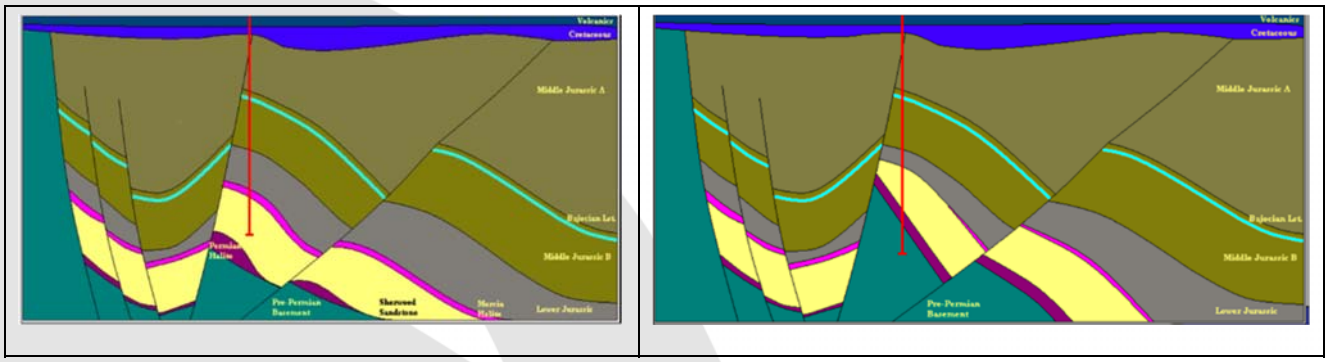


Figure 6 Shannon Prospect pre-drill (on left) and post-drill geoseismic sections (After Shell)

The average porosity of the Lower Triassic Sherwood Sandstone Group encountered in the well was 8%, bearing in mind that the top of the reservoir, which has the better quality at Corrib, was not penetrated. The top seal of the Sherwood Sandstone reservoir, the Mercia Halite, was not penetrated in the well and it is not

known if it is present over the structure. A 40m thick anhydrite unit interpreted as Upper Permian Zechstein Group was present below the Sherwood Sandstone Group. Below this a Pre-Permian interbedded sequence of sandstones, siltstones and shales was dated as Silurian based on biostratigraphical analysis of core. The Upper Carboniferous Westphalian Coals, the source rock for gas in the Slyne Basin, were absent in the well but are mapped regionally. The lateral seal to the Sherwood Sandstone reservoir are the well compacted, clay rich, Middle Jurassic shales. However late fault movements may lower the fault seal capacity.

Royal Dutch Shell purchased Enterprise Oil in 2002 soon after the Shannon Prospect was drilled. When Shell finally relinquished EL2/93 in 2004 the Deel Prospect was identified as a possible Corrib near field production prospect. The risks to the Deel Prospect identified in the Shell EL2/93 Relinquishment and Retention Report were basement involved faulting and closure to the south.

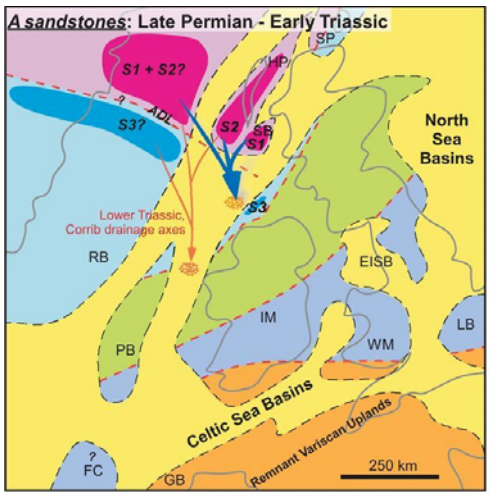


Figure 7 Triassic drainage axis Slyne Basin (Source Tyrrell et al 2007)

Providence Resources acquired Licensing Option 11/12 (which partly overlies LO16/26) in 2011. Their initial technical evaluation revealed the presence of two prospects, Kylemore and the former Shannon Prospect. The Kylemore Prospect was interpreted as a mid-basinal inverted four way dip-closed anticline based on a combination of 2D and 3D seismic data and structurally analogous to the Corrib Field. A potential gas in place of up to 228 BCF was quoted. Providence Resources and its partner in the licence First Oil Expro Ltd believed that the Shannon Prospect warranted a complete re-evaluation because the mapped structural closure was so large. Providence Resources was focussed on the development of the Barryroe Oil Field during this time and LO 11/12 expired in 2013.

The Deel/ Corrib South Prospect remains untested by drilling. Predator Oil and Gas Ventures Limited has identified a well location to test the structure. The Triassic Sherwood sandstone reservoir hosts the Corrib gas field and comprises fine- to medium-grained arkosic fluvial and alluvial sandstones with subordinate sand-flat and playa mudstone deposits. Pb isotopic data for the K-feldspar component suggests derivation from a potentially wide area to the north and west with drainage scales likely to have been in excess of 500 km. The Corrib South Prospect lies south along the drainage axes supplying the Triassic Sherwood Sandstone reservoir of the Corrib gas field (Figure 7). Further south the Triassic Sherwood Sandstone reservoir is encountered in well, 18/25-2, 27/5-1 and 27/4-1. Serica described the Triassic sandstone reservoir in 27/4-1 as of moderate quality but water wet. Given the regional distribution of the Triassic Sherwood sandstone facies and the fact that it is expected to occur at the equivalent depth to the reservoir at Corrib, the risk of not encountering adequate reservoir for gas production is low.

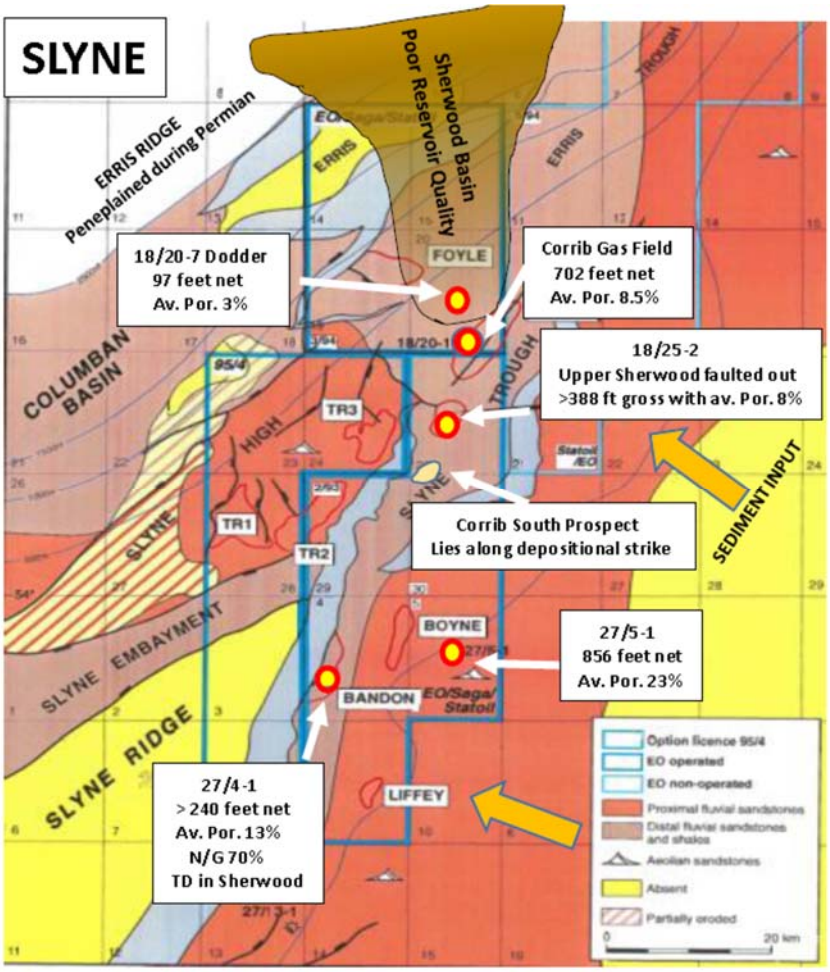


Figure 8 Triassic Reservoir Distribution (Source Predator modified after Enterprise Oil)

The Mercia Halite is the sealing formation for the Triassic Sherwood Sandstone reservoir at Corrib. The Mercia Halite was faulted out at well 18/25-2 which was drilled on a "pop up" fault block possibly related to Jurassic strike slip displacement along the Central Slyne Transfer Zone. The Mercia Halite is also absent in well 27/4-1. In well 27/5-1 to the south the Triassic Sherwood Sandstone is overlain by 30m of Mercia Mudstone but the Mercia Halite is absent. The presence of an effective Mercia Halite cap rock at the South Corrib Prospect is not certain. However where the halite is absent the Mercia Mudstone is an effective seal.

The Carboniferous, Westphalian claystones and coals are the source rocks for the Triassic Play. The Westphalian succession offshore Ireland is dominated by sandstones, coals and shales. Significant cumulative coal bed thicknesses have been observed in wells. Thirty metres of net coal is present in the Westphalian A-C section in Well 27/5-1 approximately 20kms south of the Corrib South Prospect.

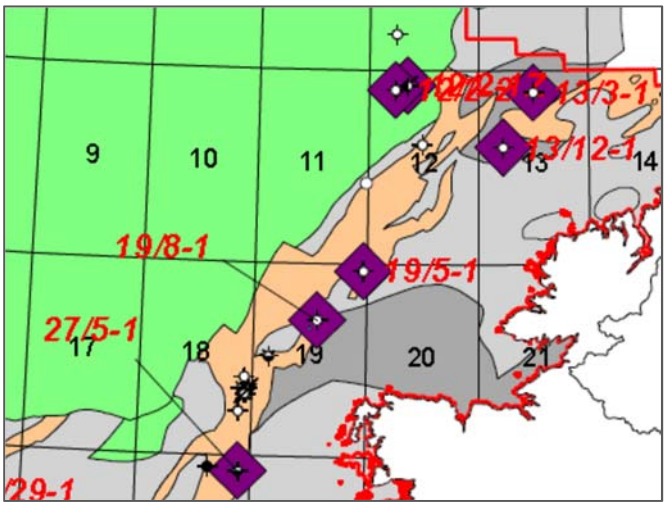


Figure 9 Wells penetrating Carboniferous offshore NW Ireland

The detailed distribution of the Carboniferous Westphalian lithofacies in the Slyne Basin is not well defined but the presence of Carboniferous source rock in the vicinity of the Corrib South Prospect is highly probable based on regional distribution from well penetrations (Figure 9) and relatively undisturbed seismic reflectors across the Slyne Basin attributed to the Carboniferous. In well 27/5-1 to the south of the Corrib South Prospect the source rock potential of the Carboniferous Westphalian was 65% TOC/wt in coals and 8% TOC/wt in claystones. Exhumation of the Slyne Basin during the Late Carboniferous-Early Permian may have temporarily arrested the maturation of the Carboniferous source rocks. However subsequent reburial during Mesozoic time, and exposure to temperatures that exceed those reached in the earlier episode of burial, would have produced renewed maturation and provided a gas charge for the Triassic Sherwood Sandstone reservoir in the Corrib South Prospect (Corcoran & Clayton, 2001). The presence of the Corrib gas accumulation confirms the certain maturity of the Carboniferous source rock where present. Communication between the Carboniferous source rock and the Triassic Sherwood Sandstone reservoir requires windows in the Permian Zechstein Halite. In the nearest offset well 18/25-2 the Zechstein is represented by anhydritic facies with no salt present. The Corrib South Prospect requires Zechstein salt withdrawal to provide Carboniferous source rock gas charge. In summary the presence of Carboniferous source rock in the vicinity of the Corrib South Prospect trap is highly probable, its maturity is certain and communication with the reservoir is possible.

A 3 way dip closure structural trap with a fault seal, in a similar setting as the Corrib Gas Field, has been mapped by Enterprise Oil, Shell E&P Ireland and Predator at the Corrib South Prospect location (Figure 10, Figure 11 and Figure 12).

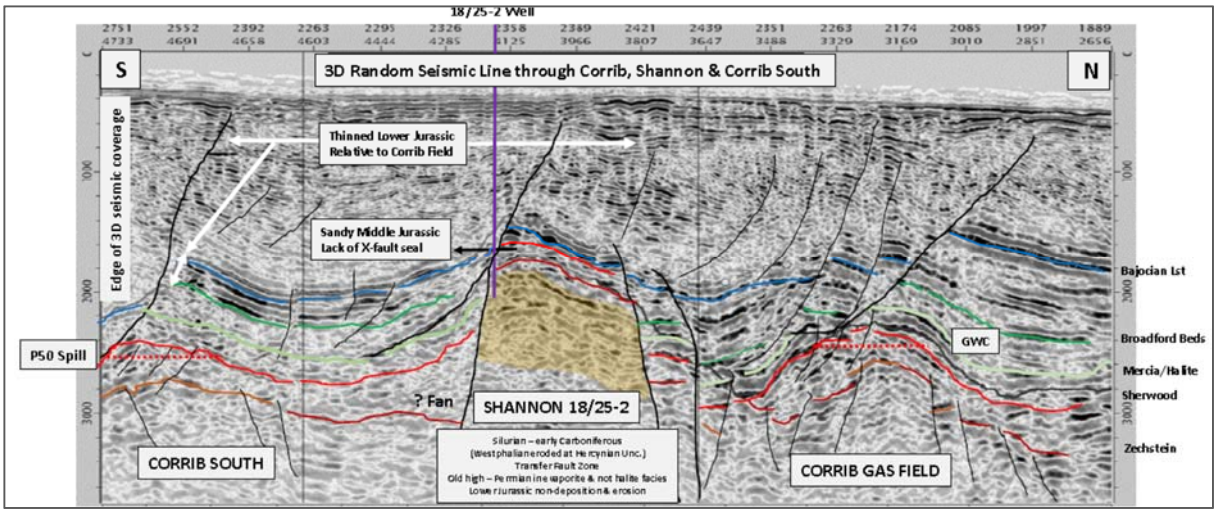


Figure 10 Seismic correlation Corrib Gas Field, Shannon 18/25-2 and Corrib South Prospect (Source: Predator modified after Shell)

The structural trap is probably effective if the fault to the SW is sealing as is the case in the Corrib Gas Field.

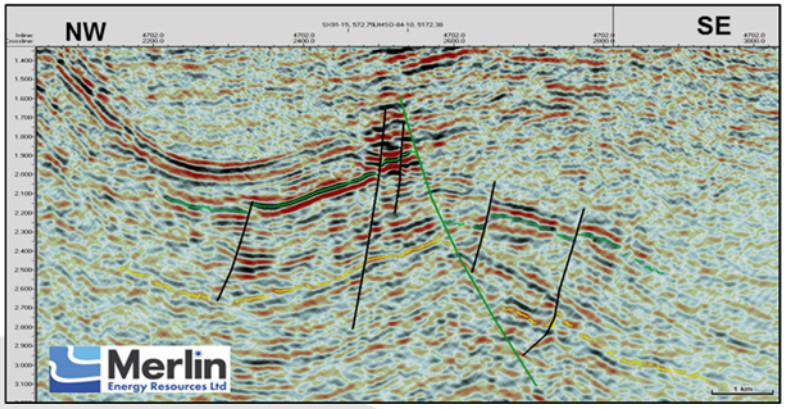


Figure 11 Corrib South Prospect 3D Seismic Line

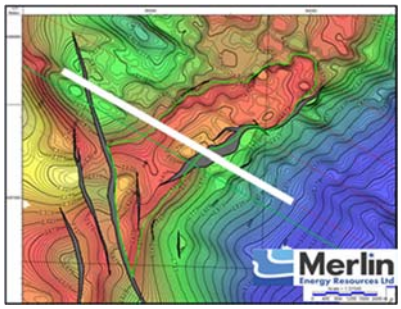


Figure 12 Seismic time to Top Triassic Reservoir showing seismic line location

3.4 Risks

The risk or geological probability of success (GPoS) or chance of geologic discovery (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018) is assessed at 30% for the Corrib South Prospect based on the probability that all the necessary components for an accumulation to form are present (Table 1).

As discussed above the primary Triassic Sherwood Sandstone gas prospect risks at Corrib South are trap development, presence of an effective seal and gas migration.

Table 1 Prospect Risking

Licence Option 16/26- Corrib South Prospect Risking (%)							
Target	Source Presence	Source Maturity	Reservoir Presence	Migration	Effective Seal	Effective Trap	GPoS
Triassic Sherwood Sandstone	95%	100%	100%	70%	75%	60%	30%

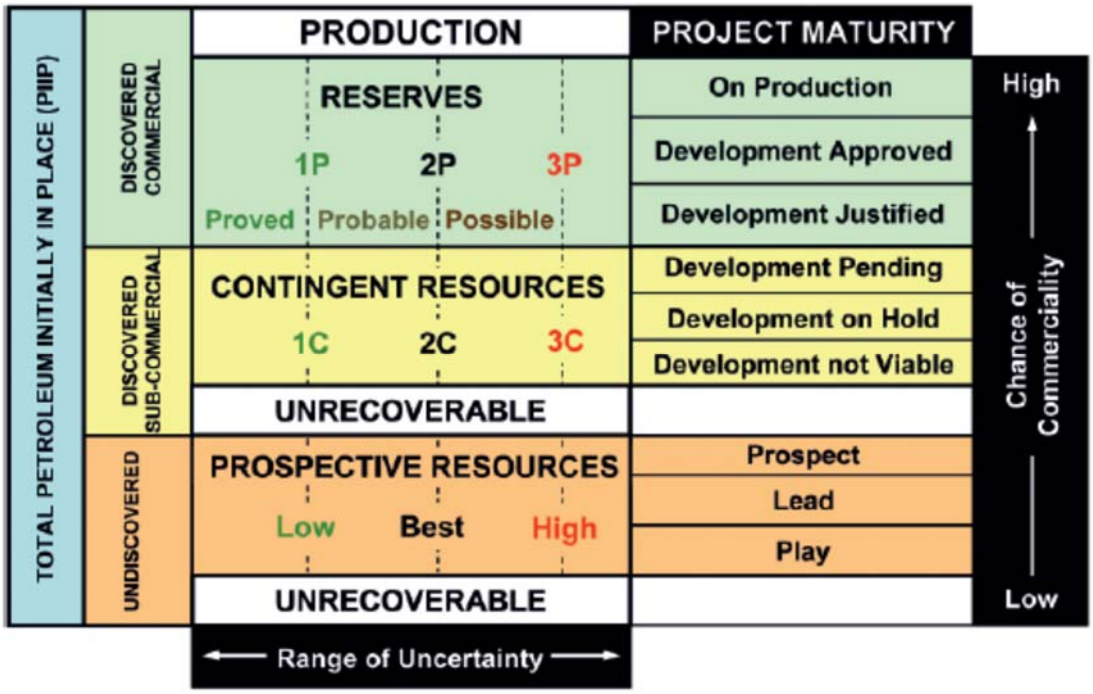
Historically the critical issue with mapping the Corrib gas field Triassic trap and similar trapping styles is whether or not Jurassic listric faulting extends through the Mercia and Sherwood intervals or soles out into the Mercia salt or its equivalent facies. Detachment of Jurassic faulting from the deeper trap forming Triassic faults is not absolutely clear from seismic data. However such an interpretation has been made by several operators in the area and it is consistent with structural styles in analogous basins with Triassic gas production such as the East Irish Sea Basin.

Since the award of LO16/26 Predator Oil and Gas Ventures Limited has submitted a progress report with initial geophysical and geological interpretation based on the results of the initial seismic interpretation. The strategy for seismic reprocessing has been identified with emphasis on re-evaluating the subtle closure of the Corrib South structure to the southwest. This subtle closure can be re-evaluated by reprocessing 2D seismic data (selected lines from the UMSO84, 82-1S, 83-IS, SFX91, E97-IE-20 and E96IE-09 surveys) subject to accessing seismic field tapes.

4.0 Resources

The resource at Corrib South is characterised as a prospective resource and low, best and high estimates were calculated in accordance with the 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System (Table 4). 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. The scheme shown below (**Error! Reference source not found.**) describes the range of technical uncertainty, for different project maturities and is based on the PRMS 2018 classification scheme. The position of prospective resources in the classification system is indicated in the bottom left of the table.

Table 2 Classification Scheme for Different Project Maturities



The Risk Factor in Table 3 is the geological probability of success (GPoS) as defined in Table 1. The low best and high estimates are calculated based on the range of values discussed below. A maximum thickness of 1250ft (381m) of Sherwood Sandstone has been penetrated in the Corrib Field (18/20-4). The base of this unit has not been encountered in the field area. The Sherwood Sandstone Group is a consistently high net-to-gross succession (field-wide average 72.1%, zonal averages per well range from 8% to 100%). The sandstones record moderate to low porosities (8.5% average in net sands, zonal average per well ranges 4.9% to 16.9%) (Dancer, et al., January 2005). In well 18/25-2, about 8km from the Corrib South Prospect, the Sherwood Sandstone reservoir is more fine grained than elsewhere and has pervasive dolomitic cement. The reservoir at Corrib South is likely to be similar in quality. The mapped areas are based on different interpretations of the spill point and fault seal. There are risks to the resource estimates associated with depth conversion where the variable velocity gradient across the structure is not well constrained.

Table 3 Corrib South Prospective Resources

Prospective Resource	Corrib	South
Triassic Gas	Units	Low
Area	acres	1,500
Net productive thickness	ft	212
Reservoir Bulk Volume	MM ft3	1.385E+10
Porosity	%	8%
Gas Saturation	%	70%
Gas Expansion Factor		0.0029412
GIIP	BCF	263.7
Recovery Factor	%	70%
Resource	BCF	184.6

Prospective Resource	Corrib	South
Triassic Gas	Units	Best
Area	acres	2,250
Net productive thickness	ft	259
Reservoir Bulk Volume	MM ft3	2.538E+10
Porosity	%	8.5%
Gas Saturation	%	75%
Gas Expansion Factor		0.0028571
GIIP	BCF	566.4
Recovery Factor	%	75%
Resource	BCF	424.8

Prospective Resource	Corrib	South
Triassic Gas	Units	High
Area	acres	3,200
Net productive thickness	ft	313
Reservoir Bulk Volume	MM ft3	4.363E+10
Porosity	%	9%
Gas Saturation	%	80%
Gas Expansion Factor		0.0027778
GIIP	BCF	1130.9
Recovery Factor	%	80%
Resource	BCF	904.7

	Gross Attributable			Net Attributable to Predator(50%)				
Prospect	Low Estimate (Bscf)	Best Estimate (Bscf)	High Estimate (Bscf)	Low Estimate (Bscf)	Best Estimate (Bscf)	High Estimate (Bscf)	Risk Factor (%)	Operator
Corrib South	184.6	424.8	904.7	92.3	212.4	452.4	30%	Predator

Table 4 Summary Corrib South Prospective Resources

The best estimate prospective resource for Corrib South is 424.8 BCF and the high estimate is almost 1TCF.

5.0 Infrastructure and Environmental Issues

5.1 Conceptual Development Plan

The development option proposed is a subsea tie in to the Corrib Gas Field. Corrib comprises subsea wells tied back to a central gathering manifold, connected to an offshore pipeline. The 20" offshore pipeline carries gas back to a landfall point and then a short distance onshore to the Bellanaboy Bridge gas processing terminal. This development option offers a connection to an established route to market with onward pipelines into the onshore grid with the onshore planning issues resolved. Spare Corrib infrastructure capacity should become available as production is forecast to begin to decline in the next few years (see below). However, Corrib reservoir pressure and deliverability issues will need to be accommodated as any new gas entering the Corrib manifold is likely to be at a higher pressure than that of the Corrib reservoir. Moreover the availability of spare capacity assumes that no other development in the area comes on stream before Corrib South.

6.0 Special Factors

6.1 Country Overview

Ireland is politically stable and close to the European gas market. Ireland has a well developed gas pipeline infrastructure, with good connections from the UK, which itself is well connected by pipeline and LNG import facilities to and from Continental Europe and further afield (Figure 17). The potential impact on Irish gas supply as a result of the UK exiting the European Union is regarded as low, as the Treaties covering the two gas Interconnectors between Great Britain and Ireland that were signed in 1993 (IC1) and 2004 (IC2) in effect guarantee that any shortage of gas in GB would be treated equally with Ireland.

In 2017, overall energy use in Ireland increased by 0.5%, while the economy grew by 7.2% when measured by GNP and by 3.0% when measured by modified gross national income (GNI*). The share of natural gas in final consumption in 2017 amounted to 15%. It has increased its share of the market slowly over the last number of years.

Moreover, the share of natural gas for electricity generation has increased significantly in recent years and now accounts for over 50%.

Imports of natural gas have increased since production from the Kinsale Gas Field started to fall in 1995. Demand peaked in 2010 and fell in the next few years as a result of a fall in economic activity following the global financial crisis. However, this reversed in 2016 and natural gas demand has risen since then. Natural gas production reached the highest level ever, as a result of the Corrib gas field coming on stream in late 2015 and increasing production in 2016 & 2017. Total gas production increased by 1.7% in 2017, when compared with the previous year. As a result, imports of natural gas fell sharply in 2016 & 2017.

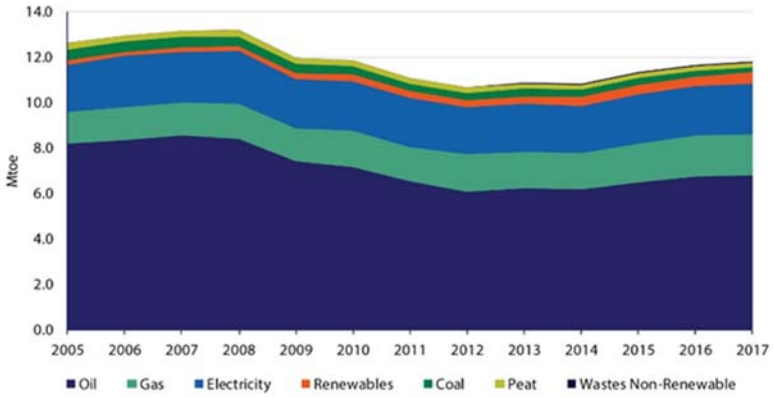


Figure 13 Total final energy consumption by fuel (SEAI 2018)

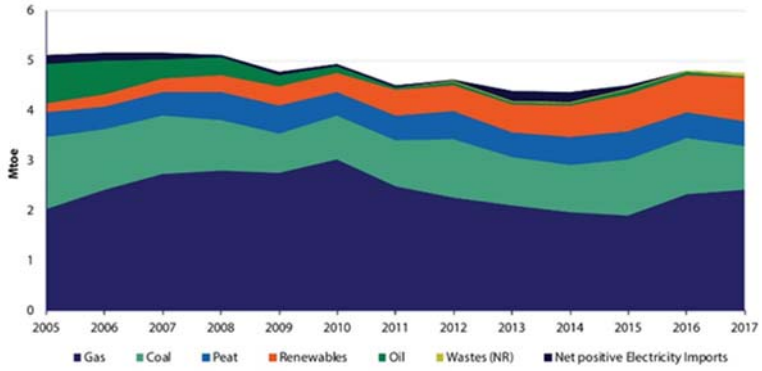


Figure 14 Primary fuel mix for electricity generation (SEAI 2018)

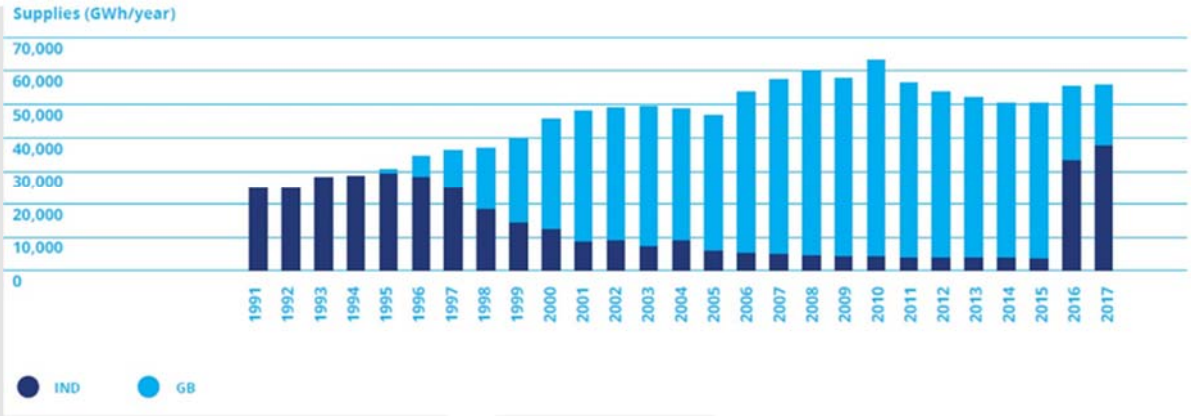


Figure 15 Indigenous and GB gas supplies (GNI 2018)

In the median demand scenario annual Republic of Ireland gas demand is expected to grow by 23.7% between 2017/18 and 2026/27 with growth of 6.7% and 36.8% forecast in the low and high demand scenarios respectively over the same horizon (**Figure 16**).

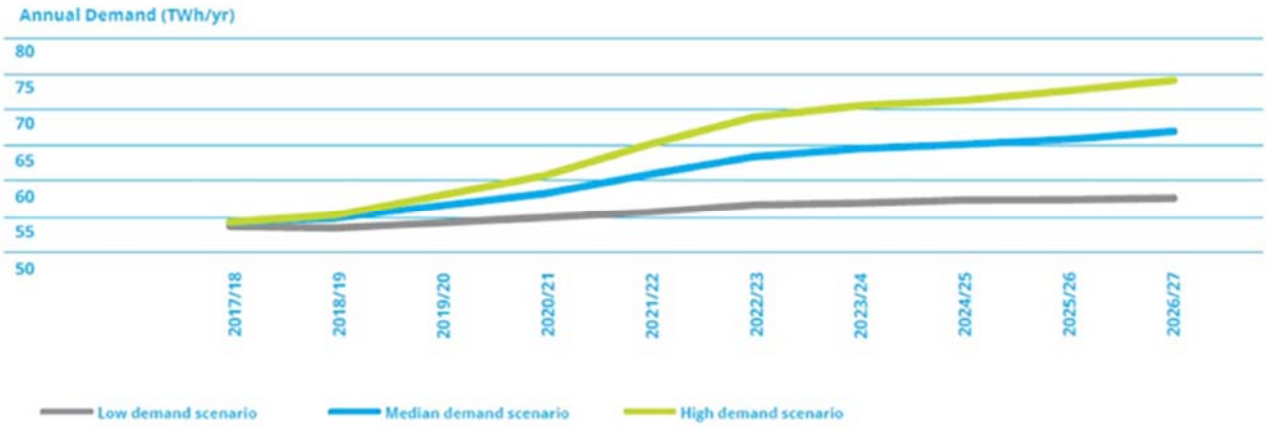


Figure 16 Total annual ROI gas demand (GNI 2018)

The level of production from the Corrib Gas Field is expected to taper off significantly in the next couple of years providing spare infrastructure capacity from the offshore area. On 30th November 2018 the sale to Canada Pension Plan Investment Board of Shell's upstream operations in Ireland, comprising the Corrib natural gas project, was completed. Vermilion assumed operatorship of the Corrib Field.

Table 5 Corrib Forecast Maximum Daily Supply (GNI 2018)

	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Daily Supply (mscm/d)	9.91	8.13	7.7	7.44	6.01	4.91	4.25	3.65	3.28	2.86
Daily Supply (GWh/d)	103.8	85.1	80.6	77.9	62.9	51.4	44.5	38.2	34.3	30.0

The Corrib Gas Field, together with marginal supplies from Kinsale Head supplied approximately 67% of annual system demands in 2017. But energy security of supply as Corrib production declines in the medium term will continue to depend on the Moffat entry point if new sources of indigenous gas are not discovered and brought on production (Figure 15). Nevertheless Gas Networks Ireland is investigating physical reverse flow at Moffat from the Republic of Ireland to Great Britain and Northern Ireland to increase market integration in the face of high swings in daily gas demand caused in part by increased wind generation. The Kinsale storage facility has commenced blowdown of Southwest Kinsale cushion gas in 2016 with production expected to cease in 2021. By 2026/27 Corrib gas supply will have declined to less than one third of initial peak production levels.

In summary there is a strong indigenous market for gas with the potential to export to GB in the event of surplus supplies if large gas discoveries are made. Any discovery at Corrib South will have the potential to utilise spare infrastructure at the Corrib field itself, the pipeline from Corrib to the Ballinaboy Gas Processing terminal in County Mayo and find a ready market in Ireland or, if there are excess indigenous gas supplies, the potential to export to GB through a reversal of the Interconnectors. It should be noted

that any initial production from Corrib South is likely to be at a significantly higher pressure than the residual pressure of the Corrib field. This will require a technical solution.

The fiscal regime is considered to be appropriate for the stage of development of the country's exploration history and reflects the relatively high risk associated with exploration in Ireland, when compared for example with the UK and Norway. The current terms, which were modified in 2014, include a Petroleum Production Tax (PPT) to apply at a variable rate of 0% to 40% linked to profitability of discoveries. This would result in a maximum rate of 55% applying in the case of new licences. There is a minimum annual PPT payment of 5% of the gross revenues of a field once production has commenced. The PPT is permitted as a deduction from Corporation Tax applying to petroleum production, which is 25%. Expenditures are subject to 100% write-off. Thus, given the low/medium cost development scenarios for a tie back to the Corrib Gas Field infrastructure, any commercial development of a small/medium sized field should prove to be commercially attractive.

It should be noted that a risk to hydrocarbon development in Ireland exists through a proposed new law. The private members Petroleum and Other Minerals Development (Amendment) (Climate Emergency Measures) Bill 2018 is at Committee Stage in the Oireachtas (Irish Parliament). It includes a proposal that would have the effect of preventing a Minister from issuing licences, undertakings or leases to companies wishing to develop hydrocarbon discoveries offshore Ireland if certain national and global environmental considerations are not met. Under Government Standing Orders the Minister for the Department of Communications, Climate Action and Environment (DCCAE) halted the legislation on the grounds that the State would face significant financial risks as a result of the Bill.

On 20th September 2019 the Climate Change Advisory Council (CCAC) advised the DCCAE that the exploration for, and recovery of new offshore oil reserves is not compatible with a low carbon transition. However, the CCAC further advised that natural gas has been identified internationally as an important transition fuel, as the global energy system switches from carbon intensive fossil fuels to low carbon and renewable systems on the way to complete decarbonisation. On 23rd September at the United Nations Climate Action Summit An Taoiseach (the Irish Prime Minister) said that he accepted the advice of the CCAC and that Ireland will now act on it. The Minister for DCCAE will bring a memo to government to set out the next steps. It is possible that positive attention may now be focussed on Celtic Sea and Slyne Basin gas prospects.

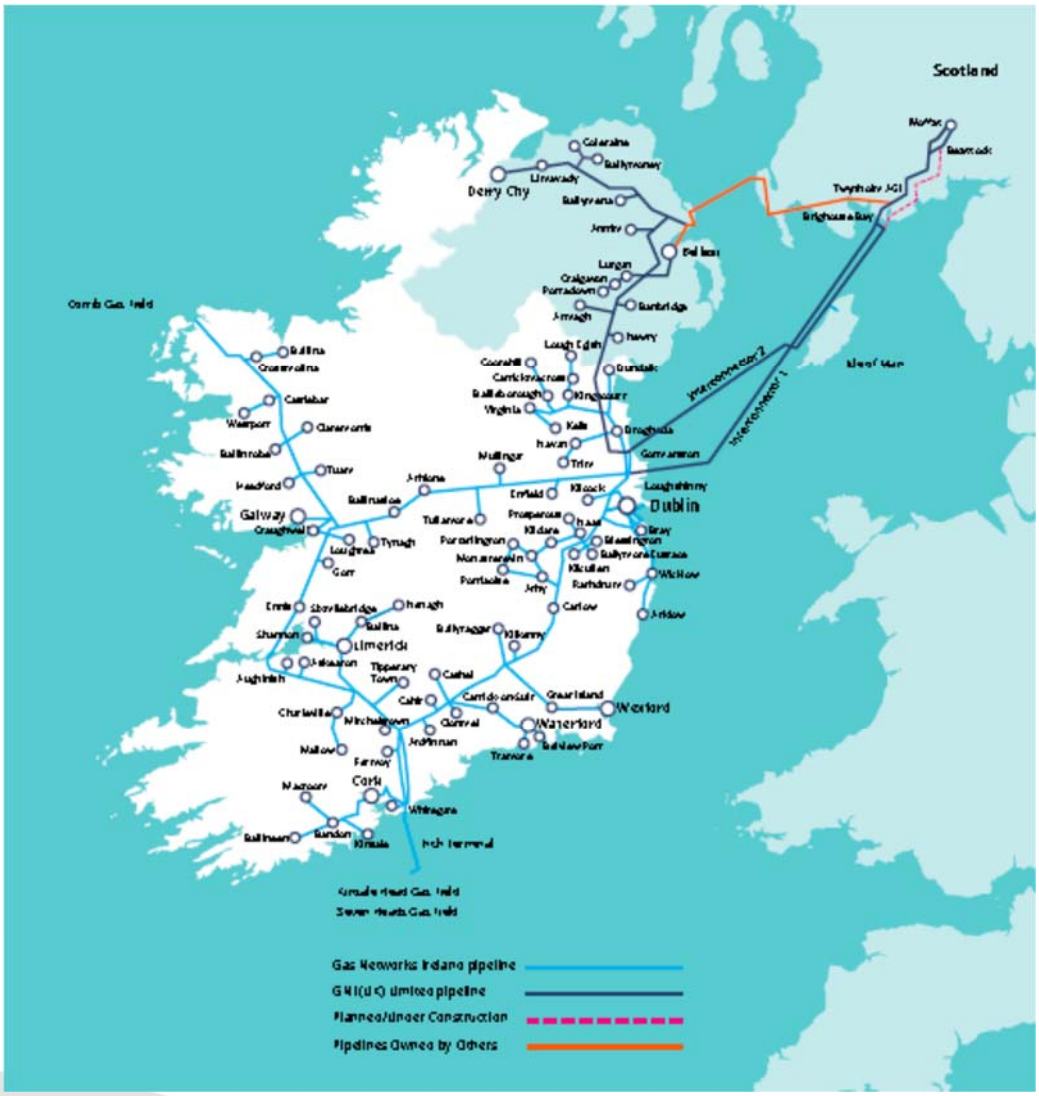


Figure 17 Overview of Gas Networks Ireland Transmission System (Source GNI)

Appendix 1

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SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018. *Petroleum Resources Mamnagement System,* s.l.: s.n.

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COMPETENT PERSONS REPORT

PREDATOR OIL AND GAS VENTURES LTD

RAM HEAD OFFSHORE IRELAND

SLR Ref: 501.00269.00003
Final
30 January 2020

BASIS OF REPORT

This document may contain information of a specialised and/or highly technical nature and the Client is advised to seek clarification on any elements which may be unclear to it.

Information, advice, recommendations and opinions in this document should only be relied upon in the context of the whole document and any documents referenced explicitly herein and should then only be used within the context of the appointment.

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1.0 Introduction

SLR Consulting (Ireland) Ltd ('SLR') of 7 Dundrum Business Park, Windy Arbour, Dublin 14, Ireland, has been commissioned by Predator Oil and Gas Ventures Limited (the "Company") to update a Competent Person's Report (the "CPR") on the company's Ram Head Licensing Option 16/30 (net interest 50%).

This CPR has been prepared in accordance with the requirements of paragraphs 131 to 133 of the ESMA update of the CESR recommendations in respect of the consistent implementation of Commission Regulation (EC) No 809/2004 implementing the Prospectus Directive to include an independent expert's report (CPR) in a prospectus document. Resources are reported in accordance with The Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018). The deterministic incremental approach was chosen because the Ram Head Licensing Option 16/30 asset is classified as contingent resources with development pending (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018) and the full range of reliable values for input parameters to a probabilistic approach are not available.

The CPR has been prepared by Mr Nick O'Neill, with assistance from Mr Richard Vernon, Mr Lloyd Vaz and Mr Martin Davies, based on data supplied by the Company, a literature search carried out by SLR and some independent verification. The data comprised details of permits and acreage interests, basic exploration geological and geophysical data, interpreted data, and technical presentations. SLR has exercised due diligence and independent analysis where appropriate on all technical information supplied by the Company. SLR has not independently checked title interests with Government or licence authorities.

Richard Vernon has more than 30 years' experience in the energy sector. After graduating with a business degree majoring in accounting and marketing, he worked as a financial analyst specialising in the Canadian oil and gas sector. He then joined the London based consultancy Petroleum Economics Limited and covered all aspects of the international oil and gas industry, including exploration/production and refining/marketing, taxation and licensing regimes, supply/demand/price strategies and forecasting, etc. for a wide range of clients including governments, international institutions and national and private oil companies. Subsequently, he moved to the US based multinational oil and gas company Phillips Petroleum Company as Director of External Affairs, responsible to the Managing Director of the Europe/Africa Division.

Martin Davies BSc FGS Chart Geol EurGeol PESGB is a Senior Petroleum Geologist. Mr Davies joined SLR in 1993 after 18 years international experience in oil and gas exploration development and production, both onshore and offshore, with British Petroleum. He has worked in Ireland, the UK, North Africa, the Middle East and the Far East. He has also worked on a number of exploration portfolio evaluations for UK and Irish based independent oil companies.

Nick O'Neill BSc MSc PGeo EurGeol MEI PESGB M AAPG is a Senior Petroleum Geologist and Director of SLR Ireland. Mr O'Neill joined SLR in 1994, having worked internationally in oil exploration operations since 1977. He was operations manager in the Middle East for an oilfield service company. He obtained an MSc in Petroleum Geology in 1986. He was operations geologist with BP and Shell in London and Aberdeen responsible for North Sea exploration operations. He has written a number of valuations and CPR reports on hydrocarbon properties in Ireland, the US, West Africa, and Italy for UK and Irish based independent oil companies.

Lloyd Vaz BSc Geol (Hons), MSc. Petroleum Geoscience is experienced in seismic interpretation, geological and geophysical modelling and petrophysical analysis. He is familiar with all technical stages of hydrocarbon exploration. He joined SLR in 2018 as a project geologist.

SLR Consulting (Ireland) Ltd. has many years of experience undertaking independent expert studies and has completed Expert Reports and Valuations for listings on the London, Copenhagen, Dublin, Vancouver, Luxembourg and Australian Stock Exchanges.

The evaluation presented in this report reflects our informed judgement based on accepted standards of professional investigation, but is subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and subsurface reservoir data. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available.

This competent persons' report has been prepared by Nick O'Neill who is professionally qualified and a member in good standing of the Institute of Geologists of Ireland, an institution relevant to the activity being undertaken, and who is subject to the enforceable rules of conduct. Nick has at least five years' relevant professional experience in the estimation, assessment and evaluation of oil and gas projects. Nick is independent of Predator Oil and Gas Ventures Limited, its directors, senior management and its other advisers; has no economic or beneficial interest (present or contingent) in the company or in any of the oil and gas assets being evaluated and is not remunerated by way of a fee that is linked to the admission or value of the issuer.

SLR confirms that, based on the information provided to it and to the best of its knowledge, there has been no material change in circumstances to those stated in the CPR and in this letter.

We confirm that SLR is responsible for this letter and the contents of the CPR and we declare that we have taken all reasonable care to ensure that the information contained in this letter and the CPR is in accordance with the facts and there is no omission likely to affect its import.

Yours faithfully,

Mr. Nick O'Neill

Director

SLR Consulting (Ireland) Ltd.

2.0 Legal Overview

On 22nd March 2019 the Minister for Communications, Climate Action and Environment approved an extension of Licensing Option 16/30 an area amounting to 799.4 km^2 over Blocks 49/19, 49/20 and part Blocks 49/13, 49/14, 49/15, 49/18 and 49/23 within the co-ordinates shown in Table 2.1 for Predator Oil and Gas Ventures Limited and Theseus Limited to 30th November 2019 subject to the following conditions:

1. During the option period Predator Oil and Gas Ventures Limited will carry out an agreed programme of work as defined below.
2. Predator Oil and Gas Ventures Limited shall hold a Petroleum Prospecting Licence during the full period of the Licensing Option.
3. Predator Oil and Gas Ventures Limited shall pay annual rental fees applicable in respect of the Licensing Option area.
4. On or before the 31st August 2019, Predator Oil and Gas Ventures Limited shall either relinquish the Licensing Option or shall have applied to have the acreage covered by the Option exclusively licensed.
5. If Predator Oil and Gas Ventures Limited applies, on or before the expiry of this Licensing Option 16/30, to licence the area reserved by way of this option, the Minister will be prepared to consider the granting of a follow-up authorisation (Standard Exploration Licence) to Predator Oil and Gas Ventures Limited covering an area to be agree with the Minister having regards to the work programme proposed by Predator Oil and Gas Ventures Limited.
6. This Licensing Option 16/30 is subject to the conditions set out herein and to the provisions as set out in the Licensing Terms for Offshore Oil and Gas Exploration, Development and Production 2007 (Licensing Terms), with particular reference to Licensing Option authorisations and the General Provisions respectively. The Licensing Terms are incorporated in and form part of the Licensing Option 16/30.
7. In granting the Licensing Option 16/30, the Minister does not necessarily accept that Predator Oil and Gas Ventures Limited has the technical or financial resources for a follow-up authorisation, and before such authorisation can be granted it will be necessary for Predator Oil and Gas Ventures Limited to demonstrate to the Minister's satisfaction that these are in place.

The LO16/30 extension to 30th November 2019 is granted subject to the carrying out of the work programme below:

1. Reprocess the GeoPartners seismic grid that covers licensing option 16/30 (12 lines overlap the maximum extent of the Ram Head 49/19-1 gas structure). Focus will be directed at improving the imaging of the Middle and Upper Jurassic gross reservoir interval.
2. Seismic attribute, AVO and Rock Property analysis for the Upper Wealden "B", "C", "D" and "E" sand intervals based on a reprocessed seismic tie between 49/23-1 (Old Head gas discovery), 49/19-1, and 49/14-1. Calibrate seismic amplitudes at 49/23-1, 49/19-1 and 49/14-1 and investigate responses over the prospective area of the Upper Wealden "B", "C", "D" and "E" Sands. Investigate the availability of shear wave logs for relevant Celtic Sea wells for input into AVO and Rock Property and fracture analysis.
3. Using available Bouguer gravity data perform 2D gravity modelling on selected 2D seismic lines based on a density and velocity model determined from the 49/17-1 and 49/19-1 well log and core data. Additionally 2D gravity modelling may help assess the maximum extent of strike closure for the 49/19-1 Middle Jurassic Structure to the east in a "data hole", covering up to 16 km^2 and lacking 2D seismic coverage
4. Middle Jurassic Bathonian Oolite and Callovian-Oxfordian red bed reservoir analysis. Using regional well data, including but not limited to 49/14-3, 49/19-1, 50/12-2, 50/12-3, 50/13-1 and 103/1-1, correlate the prospective reservoir interval and determine palaeogeographic setting, facies distribution and likely distribution and extent of sand bodies insofar as this impacts reservoir presence, thickness and porosity-permeability quality. Determine most likely reservoir properties for section faulted out in the 49/19-1 well. From the 49/19-1 NuTech well logs, cores (thin section analysis) and dipmeter logs determine potential for

the occurrence of natural fractures and their likely contribution, if any, to reservoir properties. Perform NuTech log analysis on 49/14-3 Middle and basal Upper Jurassic reservoir section to determine reservoir potential of section faulted out in 49/19-1. Integrate existing biostratigraphic data in fault offset analysis to assist with interpretation of missing interval ages. Comment on the possibility and impact of potentially over pressured zones in terms of fracture development, log interpretation, seismic interpretation, velocity analysis and seal capacity within the listed work programme items.

5. Upper Wealden "B", "C", "D" and "E" Sand reservoir analysis. Extend Upper Wealden facies analysis from the Seven Heads, Kinsale and Old Head gas fields to include the 49/14-1, 49/14-2, 49/19-1 and 49/20-1 wells. Establish the north-eastern limit of the Wealden "B" Sand tidal flat facies and the potential for tidally influenced bar sand reservoirs in Unit "C" directly overlying the Upper Wealden maximum flooding surface. Perform NuTech log analysis over the Upper Wealden in 49/19-1 and 49/14-1 to evaluate thin-bed reservoir potential below the limit of conventional log resolution. Carry out a conventional petrophysical analysis for 49/14-1 based on establishing consistency with existing petrophysical log for the Upper Wealden in the areas of the North Celtic Sea Basin prospective for dry gas.
6. Middle Wealden Sands reservoir analysis. Based on regional seismic ties and well logs, correlate the Middle Wealden claystones and the hydrocarbon-bearing sands between Seven Heads (48/24-1 and 48/28-1), Kinsale (48/20-1a), 49/17-1, Ardmore (49/14-1), 49/19-1 and Hook Head (50/11-1 and 50/11-3). Establish a palaeogeographic setting to assess facies distribution, likely extent of individual sand bodies and reservoir quality. Define the stratigraphic level and likely extent of regional seals and the role of faulting in degrading seal potential.
7. Analyse seal potential for the Upper Wealden "B" to "E" Sands and the risk to seal integrity caused by faulting. Perform NuTech analysis over the Upper Wealden in 49/19-1 and 49/14-1 to evaluate seal potential based on interpreted NuTech log-derived permeability analysis.
8. Liaise with a university research department to extend and integrate their studies of the sequence stratigraphy and palaeogeographic setting of the Purbeck and Wealden of the Wessex Basin with the equivalent section in the North Celtic Sea Basin. Integrate and extend into the North Celtic Sea their studies on the Purbeck/Kimmeridgian oils of the Wessex Basin in terms of oil properties, particularly viscosity, and new research on improving cost-effective well deliverability.
9. Map the Licensing Option Area in time and depth and use isopach maps to determine timing of structural closure for the Middle Jurassic Bathonian Oolite and Callovian – Oxfordian red bed reservoirs; the Middle Wealden reservoirs; and the Upper Wealden "B" to "E" Sands Reservoirs.
10. Investigate the potential benefits of an inclined well in the Upper Wealden for improving near-term well deliverability based on an analysis of NuTech permeability for the Upper Wealden and DST 1 test data for the "D" Sand in 48/23-3, "B" Sand in 48/23-3 and "C" and "D/E" Sand in 49/14-1.
11. Investigate the potential benefits of an inclined well in the Middle and basal Upper Jurassic gas reservoirs in 49/19-1 for improving near-term well deliverability based on an analysis of NuTech log-derived permeability for the 49/14-3 and 49/19-1 wells
12. Re-map the Middle and Upper Jurassic 49/9-1 structure to re-determine the size of individual compartments for input into reservoir simulation studies.
13. Carry out an engineering study to determine the technical feasibility and cost of re-entering the 49/9-1 well to flow test the Middle and Upper Jurassic gas-bearing interval to assess potential flow rates and any evidence for pressure depletion from an extended well test.
14. Carry out an engineering study to determine the technical feasibility of a tie-back either to the Kinsale platform or to an enlarged onshore terminal facility at Inch brown field site utilising the existing pipeline to shore.
15. Re-determine Project Economics based on the feasibility of the above development options and incorporating the proposed new entry and exit point tariffs and capacity protocols currently being discussed by the TAR Network Code Workshop, of which Predator is a member of the liaison Group.

16. Carry out a gas marketing study based on the outcome of Virtual Reverse Flow ("VRF") discussions by the TAR Network Code Workshop and the treatment of VRF as an interruptible product within the TAR EU Network Code - VRF and the ability to export to the UK is significant as the volumes of indigenous gas in a Success Case from various projects offshore Ireland would undoubtedly necessitate export through the infrastructure to the UK.
17. Quantify geological risks and chance of success. Volumetrics to be calculated on all prospects and leads identified in the Licence Option Area.
18. Incorporate the results of the detailed mapping of all prospects and leads, of the geological interpretation of each of these features, and of the perceived risks attached to them, into a comprehensive Technical Report to be submitted to the PAD no later than 3 months before the expiry of the proposed Licensing Option.
19. A decision to proceed to an Exploration Licence, or not as the case may be, to be made on or before 60 days prior the end of the Licensing.

Table 2.1 Coordinates of LO16/30

A.	51 deg 32' 00" N,	7 deg 26' 00" W.
B.	51 deg 32' 00" N,	7 deg 18' 00" W
C.	51 deg 30' 00" N,	7 deg 18' 00" W
D.	51 deg 30' 00" N,	7 deg 12' 00" W
E.	51 deg 33' 20" N,	7 deg 12' 00" W
F.	51 deg 33' 20" N,	7 deg 00' 00" W
G.	51 deg 20' 00" N,	7 deg 00' 00" W
H.	51 deg 20' 00" N,	7 deg 24' 00" W
I	51 deg 16' 20" N,	7 deg 24' 00" W
J	51 deg 16' 20" N,	7 deg 30' 00" W
K	51 deg 28' 30" N,	7 deg 30' 00" W
L	51 deg 28' 30" N,	7 deg 26' 00" W
A.	51 deg 32' 00" N,	7 deg 26' 00" W

On the 9th April, 2019, Predator wrote to the Petroleum Affairs Division accepting the one year extension of the term of Licencing option 16/30 to 30th November 2019.

With respect to the agreed work programme Predator Oil and Gas Ventures Limited has made significant progress. The main conclusions of the work to date are as follows:

1. The discovered dry gas (logged but not tested in 49/19-1 in 1984) crucially is contained in reservoirs with better reservoir characteristics than have previously been reported;
2. The 2015 GeoPartners regional multi-client 2D long offset broadband seismic acquisition is of far superior quality compared to any of the existing vintage and reprocessed seismic data;
3. The GeoPartners survey is not optimally processed to image the gas-bearing Middle and Upper Jurassic and these data will therefore benefit from reprocessing, with the effort focussed on this key reservoir interval;
4. Reservoir engineering studies indicate the feasibility of taking the gas to compression sited either offshore on the Kinsale platform or onshore at the Inch terminal - for either option to be exercised the existing pipeline to shore from Kinsale must remain viable and in place;

5. The key element to de-risk is the ability of the gas reservoirs to deliver at the rates simulated by the reservoir engineering study and the potential for pressure depletion related to compartmentalisation. This can be achieved through a re-entry and testing of three gas zones in the 49/9-1 well. The re-entry and testing of 49/9-1 is a more cost effective way of testing gas deliverability and estimating connected volumes compared to acquiring 3D seismic and drilling a new appraisal well.

Predator's forward strategy is to reprocess the GeoPartners seismic to improve the imaging of the Middle and Upper Jurassic gross reservoir interval and apply for a Standard Exploration Licence with a proposed initial three year work programme to include a well site survey, re-entry and testing of 49/19-1 followed by 1,000 km^2 of 3D seismic acquisition and processing contingent upon the results of the 49/19-1 testing programme.

3.0 Geological Overview

3.1 North Celtic Sea Basin

LO 16/30 is located in the North Celtic Sea Basin, one of a number of parallel elongate NE-SW trending basins that lie off the south coast of Ireland. Within the North Celtic Sea Basin, Triassic to Tertiary sediments are found in accumulations up to 9 km thick, overlying Devonian to Carboniferous Palaeozoic basement. While the basin has undergone numerous inversion episodes, Triassic and Jurassic sequences are well developed with variable thicknesses of Cretaceous and Tertiary cover.

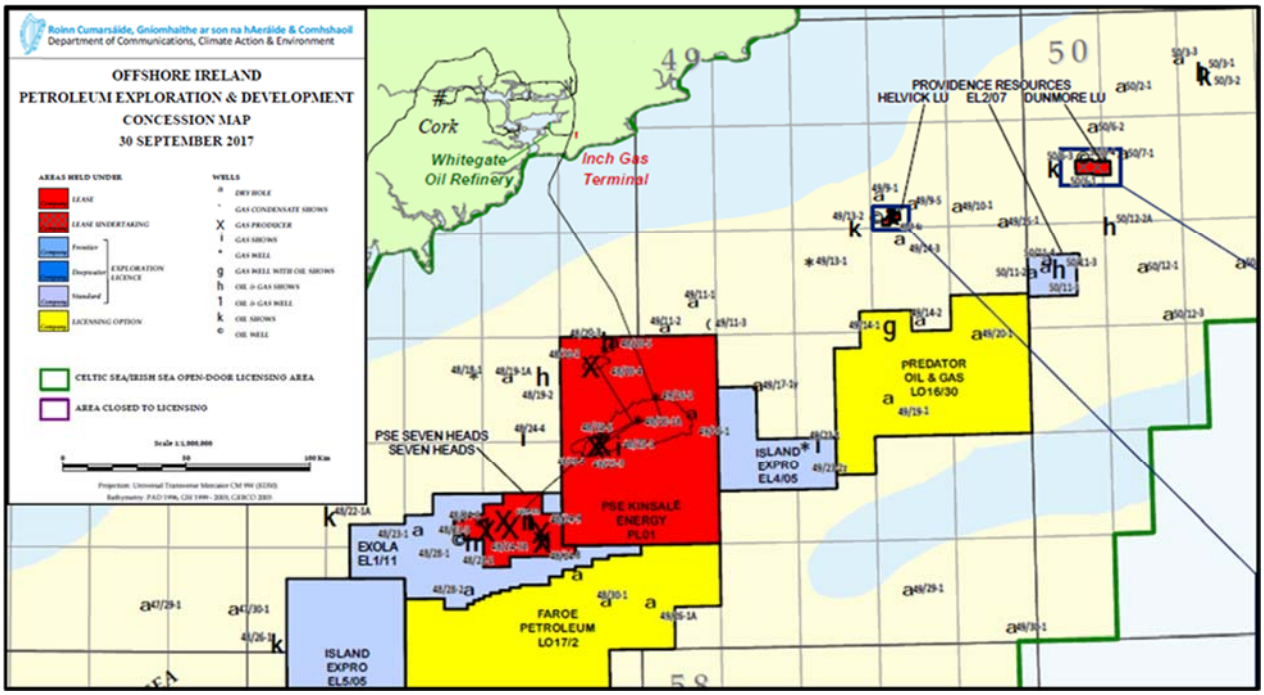


Figure 1 Location of LO16/36 and Kinsale Production Lease in the North Celtic Sea Basin (Source: PAD)

Regional studies suggest that basin development was initiated during Triassic time. The main phase of rifting was initiated during the Jurassic. The Lower Jurassic succession is dominated by a shaly marine sequence which is thought to be the main hydrocarbon source in the basin. These shales were succeeded by shallow water marine shelfal limestones of Middle Jurassic age. The main extensional phase of rifting occurred in Late Jurassic times with the development of significant hanging wall synclinal depocentres. The associated footwall uplift of areas close to these depocentres resulted in the development of a facies architecture which is thought to be related to contemporaneous basin structure. This resulted in rapid facies changes that are observed throughout the Upper Jurassic which is dominated by marine shales and limestones but also locally contains terrestrial deposits. At the Jurassic-Cretaceous boundary non-marine and lacustrine Purbeckian shales signify the onset of the non-marine mixed fluvial-alluvial Wealden succession as well as being the source of a waxy oil that is observed in wells throughout the basin. A major marine transgression represented by Albian Greensand shelfal sandstones progressively overlies the Wealden sequence. The Albian Greensand succession is the main reservoir for the Kinsale Head Gas Field. The Greensand is overstepped by the Gault Clay marine claystones as the basin continued to undergo post rift thermal sag. This is succeeded by a thick succession of middle to outer shelfal Upper Cretaceous chalk which marks the culmination of the Cretaceous transgression. Regional Tertiary basin inversion has led to the removal of much of the younger section across the area. In addition this compressive event has led to the formation of a number of mid basin inversion induced anticlines with some associated strike slip faulting (O'Sullivan, 2001).

Three petroleum plays are identified in the basin: oil and gas plays in Jurassic reservoirs, an oil play in the Cretaceous Middle to Lower Wealden and a gas play in Cretaceous Upper Wealden and Greensands. The basin contains the 1.7 TCF Lower Cretaceous Kinsale Head Gas Field which is almost depleted with cessation of production expected in 2021. The operator PSE Kinsale Energy sought regulatory approval for decommissioning in 2018. Submissions for the public consultation process closed o 17th December 2018 and a decision by the Minister is awaited.

This CPR is focussed on oil and gas potential in Jurassic reservoirs identified by the Marathon dry gas discovery well 49/19-1.

3.2 Stratigraphy

The stratigraphy in the North Celtic Sea Basin (NCSB) is well known, and sand packages in the Lower Cretaceous include the Greensand, Upper Wealden, Middle Wealden, Lower Wealden and Basal Wealden (Figure 2) As most wells do not penetrate below the topmost Jurassic, Jurassic stratigraphy is relatively poorly-known. A significant amount of well data concentrates on small areas such as the Hook Head area, with little regional data to expand reservoir thicknesses and facies trends. Known Jurassic sediments are shale-dominated with sand and carbonates known to exist at multiple levels within the Upper Jurassic (Kimmeridgian-Oxfordian), Middle Jurassic (Bathonian) and Lower Jurassic (Hettangian). These sequences are though to comprise the main seismic reflectors. To the southwest, in the Fastnet Basin, Lower Jurassic sands have been documented (Fastnet Petroleum, 2012). While Upper Sinemurian (Lower Jurassic) sandstones exist in wells 50/3-1, 50/3-3 and 49/9-1, it has not been discovered in wells 49/19-1 or 49/20-1, indicating the Lower Jurassic reservoir development is uncertain. Permo-Triassic sequences are thought to exist beneath the North Celtic Sea Basins but are poorly known.

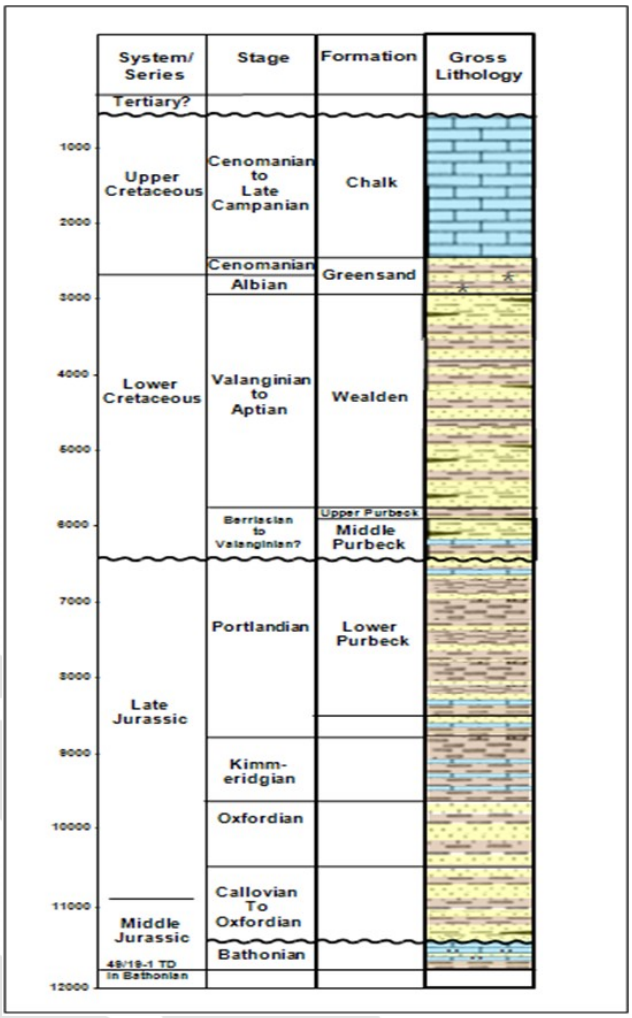


Figure 2: Generalised Stratigraphy of LO16/30

Reservoir

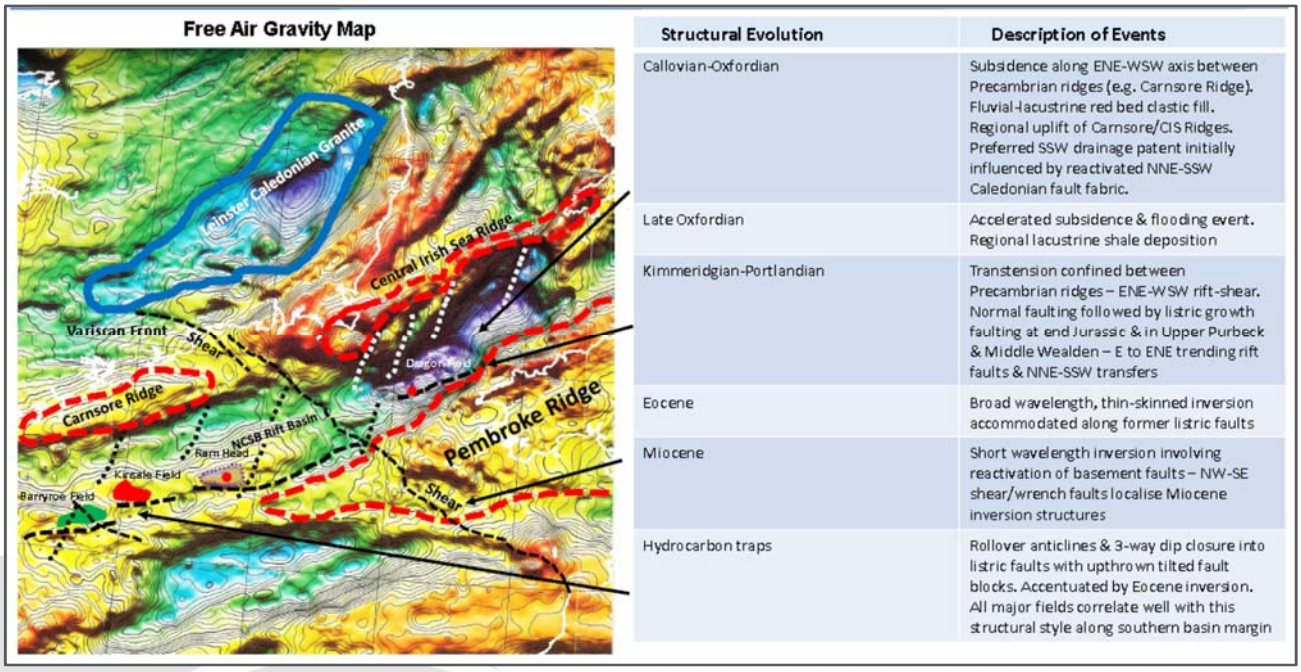
Within the License Option, five main reservoir units have been identified:

- Middle and early Upper Jurassic reservoirs
- Late Upper Jurassic (Portlandian) reservoirs
- Early Cretaceous Purbeckian (Berriasian) reservoirs
- Basal, Lower, Middle and Upper Wealden ("B" and "E" Sand) reservoirs

Middle and Upper Jurassic Reservoirs

Callovian-Oxfordian fluvial sands were the primary objectives of well 49/19-1. Nearby well 49/19-2 encountered oil in the same sand formation and flow-tested them at 6,000 BOPD. The Bathonian Oolite was also a reservoir target at the time.

The British Geological Survey (BGS) has produced regional free air gravity maps of the area, showing an elongated gravity high and east-west faulted margin in the North Celtic Sea Basin. This confirms current regional studies placing the 49/19-1 straddling the major fault zone, across which there is a marked change in the regional dip of the Middle and Upper Jurassic sequences from south to north towards the inverted axis of the NCSB.



Structural Evolution	Description of Events
Callovian-Oxfordian	Subsidence along ENE-WSW axis between Precambrian ridges (e.g. Carnsore Ridge). Fluvial-lacustrine red bed clastic fill. Regional uplift of Carnsore/CIS Ridges. Preferred SSW drainage patent initially influenced by reactivated NNE-SSW Caledonian fault fabric.
Late Oxfordian	Accelerated subsidence & flooding event. Regional lacustrine shale deposition
Kimmeridgian-Portlandian	Transtension confined between Precambrian ridges – ENE-WSW rift-shear. Normal faulting followed by listric growth faulting at end Jurassic & in Upper Purbeck & Middle Wealden – E to ENE trending rift faults & NNE-SSW transfers
Eocene	Broad wavelength, thin-skinned inversion accommodated along former listric faults
Miocene	Short wavelength inversion involving reactivation of basement faults – NW-SE shear/wrench faults localise Miocene inversion structures
Hydrocarbon traps	Rollover anticlines & 3-way dip closure into listric faults with upthrown tilted fault blocks. Accentuated by Eocene inversion. All major fields correlate well with this structural style along southern basin margin

Figure 3 North Celtic Sea Structural Elements based on Free Air Gravity Data (Source: Predator)

The Middle and Upper Jurassic Callovian-Oxfordian sands are interpreted as shallow-water fluvial deposits with a number of upward fining channels. These sands are the reservoir of the Marathon 49/19-1 gas discovery. The Callovian-Oxfordian sands also tested oil, condensate and gas in 49/9-2, 50/6-1 and in the Dragon Field in St Georges Channel. This reservoir was also encountered in well 50/13-1 northeast of LO 16/30. Improved correlation of the Late Bathonian to Oxfordian section has identified three distinct reservoir intervals that can be regionally correlated on the basis of differing source terrain components, environments of deposition and gross wireline log character.

Late Upper Jurassic Reservoirs

Late Kimmeridgian to Portlandian strata has been identified as a gas/condensate prone source rock of optimum maturity for wet gas generation, due to presence of terrestrial kerogens (Marathon 49/19-1 Geochemistry Report). Argillaceous limestones are present in thin beds as are well-cemented sandstones, and the frequency of these

sequences increases shelf ward (e.g. well 50/3-2) although thin sands remain present in basinal wells such as 48/24-3 and 48/25-1.

There is uncertainty in the depositional environment of Late Upper Jurassic low energy sediments as few studies have been carried out on spatial distribution of facies types. Cores and sidewall cores are rare due to operational limitations imposed by risks from overpressured zones, which also imposed a necessity to drill over-balanced and thus possibly incur formation damage. Little separation of shallow and deep resistivity curves is observed, suggesting that low porosity and permeability has resulted in low mud invasion – rare sidewall cores support this. However, "sweet spots" have been observed in some Upper Jurassic sands of well 49/19-1. The improved porosity may be due to the effect of formation overpressure that can reduce burial overburden and burial diagenesis in some of the thicker, upward fining, fluvial channel sands.

Over-pressuring is likely to have been generated by sediment dewatering as a result of rapid sedimentation, burial and hydrocarbon expulsion from source rocks prior to and/or during Tertiary inversion. While fractures are seen in sidewall cores from the Upper Jurassic, where carrier beds and fractures are absent, gas has accumulated *in situ* in micro-porosity associated with shale and porous sandstones. Fractures in shale are seen in Upper Jurassic core in 48/25-1 between 10,811 and 10,840 ft, up to 8 cm in width and cemented with secondary calcite fill. High pressure gas bleeds and flows of between 7 and 10 barrels of oil were discovered in this well, with connection gas kicks of up to 24%, apparently in non-reservoir sections – these are associated with natural fracture systems generated by pore pressure build-up and the resultant hydraulic fracturing. Varying competencies of thinly bedded shale, cemented sandstone and argillaceous and recrystallized limestone would have assisted this process. Calcite cementation may be of early origin and relating to dissolution and precipitation of carbonate minerals in interbedded limestones. An understanding of this diagenetic history will inform evaluation of preserved fracture porosity.

Fractures resulting from over-pressuring generally have lower permeabilities than tectonically-derived fractures. They can, however, contribute porosity to low porosity formations. Here, tectonic-related fracturing may have occurred due to late Jurassic extensional faulting and Tertiary basin inversion.

Early Cretaceous Purbeckian (Berriasian) reservoirs

The secondary objective of well 49/19-1 was fluvial sands of Middle and Upper Purbeck age, that had oil shows in the nearby 50/11-1 Hook Head Structure. Traces of oil were found in the same interval in well 49/17-1 but testing was unsuccessful. Within well 49/19-1, upward fining fluvial channel sands were found to be oil-bearing below 6100 feet. While testing was unsuccessful, a skim of oil was recovered and found to be of high wax content with a viscous, high pour point nature (similar to other North Celtic Sea Basin Lower Purbeck oils).

This oil-bearing interval has been linked to the so-called "Basal Wealden Sands" in well Barryroe 48/24-10z, which tested for hydrocarbons at potentially commercial rates. However, while the Barryroe well 48/24-10z tested an inversion anticline, the oil bearing sands encountered in 49/19-1 are developed within a tilted fault block generated prior to basin inversion. A second zone, which features thin-bedded limestones and well cemented sandstones, was tested in 49/19-1 at the top of the Lower Purbeck (6280 feet). The interval did not flow on test even after stimulation. The log character of the interbedded limestone-sandstone sequence is similar to the interval penetrated at the top of the Lower Purbeck in Seven Heads well 48/23-1, suggesting lateral continuity. Comparison with well 49/17-1, 23 kms away, suggest that much of the Upper Purbeck is missing in 49/19-1 either due to non-deposition or erosion.

Basal, Lower, Middle and Upper Wealden ("B" and "E" Sand) Reservoirs,

The stratigraphy of the Cretaceous is well known in the North Celtic Sea Basin. A number of Lower Cretaceous sand packages are recognised. These include from top to bottom the Greensand, the Upper Wealden, Middle Wealden,

Lower Wealden and basal Wealden. The Middle Wealden to Top Purbeck in well 49/19-1 contains several reservoirs with indications of residual and movable oil. The main reservoir in the Barryroe oil discovery is equivalent to this section. The 49/19-1 well was drilled deliberately off structure at the top of the Upper Wealden as the Greensand and Upper Wealden were not reservoir objectives at that time.

Source Rocks

Three key source rocks are recognised in the North Celtic Sea Basin: Lower Jurassic (predominantly Toarcian), Upper Jurassic (predominantly Oxfordian/Kimmeridgian) and topmost Jurassic/base Cretaceous (predominantly Portlandian/Purbeckian) sequences. The Ballycotton, Kinsale and Seven Heads gas accumulations are considered to be the product primarily of the biodegradation of existing oil accumulations. Biogenic gas from the Wealden is also suspected by some to contribute to charge in the Kinsale Head gas field (O'Sullivan 2001, 2012).

Regional Lower Jurassic (Toarcian) source rock is well documented (see Scotchman, 2001) and its distribution is now well-known. Scotchman presents Toarcian source rocks as averaging 187 m thick in the NCSB, being oil prone in the basin and gas prone at basin margins. While Jurassic strata are largely absent at the Pembrokeshire High, Toarcian sequences are present in the North Celtic Sea and South Celtic Sea Basins, as well as the Central Irish Sea Basin. Lower Jurassic sequences are also proven light oil source rocks in the Fastnet Basin. Viable source rock is described in the following four wells:

- 42/21-1: TOC of 1.5 to 3.0%, S2 of 4.0 to 13.9 kg/t and HI of 254 to 525
- 49/19-1: TOC of 1.5 to 2.3%, S2 of 0.5 to 5.1 kg/t and HI of 35 to 222
- 49/29-1: TOC of 2.7 to 5.7%, S2 of 8.5 to 20.6 kg/t and HI of 283 to 383
- 50/3-1: TOC of 1.1 to 2.7%, S2 of 2.9 to 9.5 kg/t and HI of 188 to 406

Younger Kimmeridgian and Portlandian/Purbeckian source rocks have been encountered in well 49/19-1, but appear to be only marginally mature. While the Kimmeridgian appears to be a poor to moderate gas prone source rock, Portlandian/Purbeckian sequences are said to be excellent oil/gas prone source rocks. Towards the basin centre, in the northwest of the LO 16/30, Purbeckian sequences may be sufficiently mature for oil generation. Geochem Labs suggest that the oils from well 49/19-1 can be tied to Purbeckian source rocks.

There is significant source rock potential in the Greater Helvick Area. Helvick gas was found to differ from gas produced elsewhere in the Celtic Sea in that is most likely a mix of thermogenic and primary biogenic gases (as opposed to the strong secondary microbial degradation signature exhibited by Seven Heads, Ballycotton and Kinsale Head). Oils recovered in this area exhibit a clearly lacustrine signature with additional markers of a marine character. It is unclear whether the mixing was from dual sources or from localised marine incursions during source rock deposition (Armstrong, et al., 2017).

With respect to oil and gas generation and migration history the Lower Jurassic source rocks probably started generating oil and some gas in the Upper Jurassic in the basin centre and continued generation throughout the Lower Cretaceous going into the gas window. After the Lower Cretaceous there is a poorly understood period of Upper Cretaceous inversion suggested. There was a great "Chalk" down warp over much of the NCSB and only gentle subsidence or hiatus in adjacent areas. Initial gentle down warp in the early Tertiary was followed by a major inversion. This inversion is thought to have brought generation of hydrocarbons to a halt in most areas and to have re-distributed already migrated and trapped hydrocarbons in the basin. There is extensive evidence of residual oil, oil rims to gas fields, heavy oil, biodegraded oil and mixed oils that suggest early accumulations have been tilted or breached and in some cases refilled by later gas migration. In some areas gentle down warp resumed in the late Tertiary although much of the NCSB has Chalk at seabed.

Seal

At Mid Cretaceous Greensand level the seal is provided by the Gault Clay. This is a proven caprock at the Kinsale Head Gas Field. The Gault Clay is thought to be thin but effective over most of the LO 16/30 area. The middle part of the Wealden sequence contains a thick series of shales and siltstones that act as effective caprocks for the proven Barryroe and Old Head prospects. The same caprock is expected to be well developed in the LO 16/30 area. The thick Purbeckian sequence is predominately shaly and is the seal for the nearby Hook Head and Helvick discoveries. The Top Callovian-Oxfordian red bed fluvial clastic, and Middle Jurassic Bathonian sandstone and limestone, reservoirs are likely to be capped by either Middle Jurassic shales or by Upper Jurassic shales of Oxfordian or younger age that unconformably overlie this sequence. Similarly any sandstone reservoirs in the Lower Jurassic are likely to have thick shale seals.

Cap rock seal is not an issue in the NCSB but fault seal is. This is largely a result of the Tertiary inversion (and maybe Late Cretaceous inversion also) moving faults that had sealed earlier accumulations. The fault movements resulted in loss of light ends (giving heavy oil) or in more extreme cases causing extensive biodegrading of oils. This is particularly evident in the Jurassic where some fault blocks are sealed and other water wet (e.g. Helvick). It also occurs locally in the Wealden sequence. Faulting, especially late faulting in the Cretaceous also causes reservoir compartmentalisation – evident in the Seven Heads area.

3.3 Exploration History and Database

Numerous 2D seismic surveys intersect LO16/30, with one 3D survey to the North, centred on well 49/2-2 (Figure 4). The earliest 2D seismic surveys were carried out by Marathon Oil beginning in 1972. Marathon drilled 49/9-1 on a very sparse 2D grid in 1984. Further 2D surveys were carried out on Quad 49 in 1988, 1989, 1990, and 1994. Following their surrender of the licence in 1995, Arcon (now Providence) acquired 2D on Quad 49 in 1998 and 2006. A 3D survey was carried out in 1998 to the north of LO 16/30 by Providence Resources. Fastnet Oil and Gas acquired 3D seismic in Quad 49 to the west of LO 16/30 in 2013. A GeoPartners regional multiclient 2D long offset broadband seismic survey was acquired in 2015. It provides a consistent grid of data across the main Middle and Upper Jurassic structure tested by the Marathon 49/19-1 well and therefore minimises the issues created by different frequency content, misties and polarity changes created by different acquisition parameters.

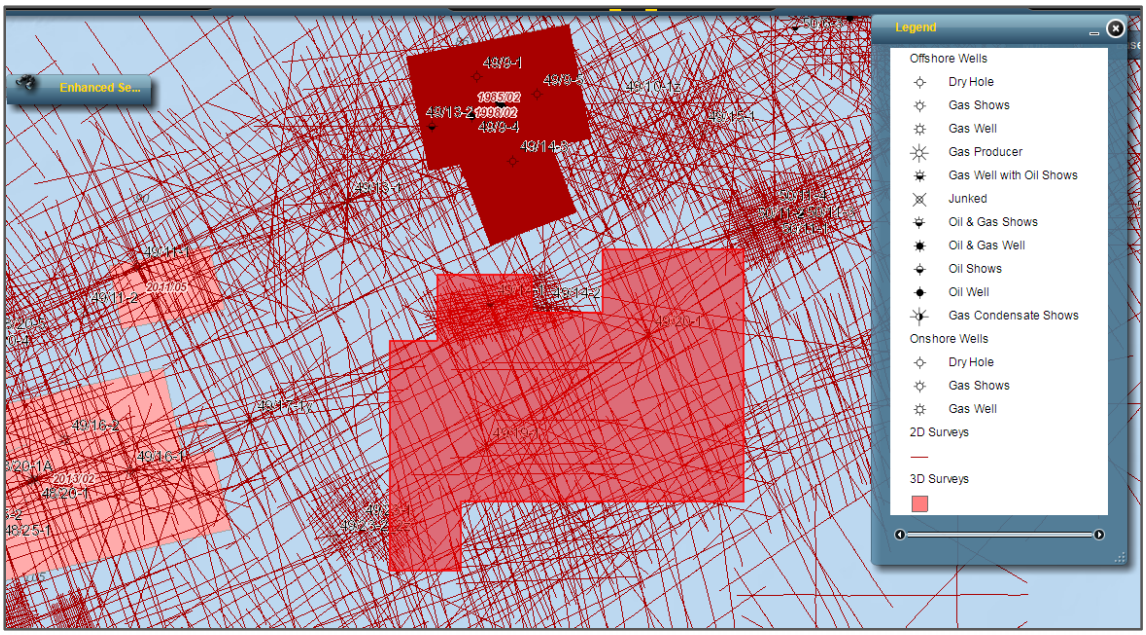


Figure 4 Seismic coverage (2D and 3D) in the LO 16/30 Area (Source: PAD IPAS)

A number of oil discoveries have been made at a number of stratigraphic levels: both Helvick and Dunmore are oil discoveries hosted in Upper – Middle Jurassic sandstones. Petroleum system source rock for both discoveries is reported to be marine shales of Toarcian age. The Helvick discovery tested flow rates of >6,600 bbl/d (well 49/9-2). The nearby Ardmore gas discovery features a heavy oil (16° API) rim of approximately 230 MMBO (Providence, 2010).

In the North Celtic Sea Basin, two reservoirs commonly hold gas accumulations: Greensand ("A Sand") and Upper Wealden ("B Sand") – for example the Kinsale Head Gas Field is hosted in both "A Sand" and "B Sand" reservoirs, with original gas-in-place of 1.7 TCF. While the A Sand forms laterally continuous sheet sandstone, the B Sand forms a series of sands 5-10 feet thick in a 60 foot section. In addition to this field, the A and B Sands have been identified as the reservoir members for Ballycotton (64 BCF), Seven Heads (25 BCF), Old Heard of Kinsale (45 BCF), Schull (30 BCF) gas fields, as well as Galley Head, and Carrigaline. Lower Jurassic source rocks form thick successions throughout the North Celtic Sea Basin, with gas generation likely to have begun during the Late Cretaceous and halted during Miocene inversion. Gas is dry and attributed in part to biogenic sources, possibly from lignite sequences within the Wealden (O'Sullivan, 2011). Re-migration of gas has been identified. Early failures in exploration targeting the Wealden or Greensand sequences has been attributed to wells having been drilled off-

structure, outside the play fairway or gas charges not displacing earlier oil charges. Evidence of failure from leaking faults has not been identified.

Three wells are located within the boundaries of LO16/30, the Ardmore gas discovery 49/14-1, the Helvick gas discovery 49/19-1, and 49/20-1. One other well, 49/14-2, is situated on the northern boundary of LO16/30.

Figure 5: LO16/30 Ram Head boundaries and associated well locations.

Well 49/14-1 was spudded in October 1974 as a vertical exploration well drilled by Marathon to a depth of 7964 ft (MD) targeting the Lower Cretaceous Wealden Ardmore prospect. The well tested gas at 8 mm cfd from the Upper Wealden. The follow up appraisal well 49/20-1 was drilled from August to September 1975 by Marathon. This well was a vertical exploration well targeting the South Ardmore prospect. Both wells were plugged and abandoned. Marathon drilled 49/19-1 from September 1984 to January 1985 targeting oil in the Middle and Upper Jurassic sandstones and oolitic limestones of the Helvick Prospect. They encountered a 270 ft gross gas column in Middle and Upper Jurassic sandstones. The well was not tested because there was no market for gas in Ireland in 1985.

Arcon (now Providence) acquired 2D and 3D high resolution seismic in 1997 and 2006 to further evaluate the 49/14-1 Ardmore gas discovery and its heavy, waxy oil leg. Fastnet Oil and Gas farmed into LO 12/05 which overlapped the current LO 16/30 in 2012. Some desk-top studies were completed but the LO was relinquished in 2015 when the company diverted its investments to focus on the pharmaceutical industry.

LO 16/30 was awarded to Predator and Theseus Ltd in 2018 for a two year period. The term of LO 16/30 was subsequently extended to 30th November 2019.

Table 3.1 Drilling activity and well details in the vicinity of LO16/30 Ram Head

Well No	Year	Operator	Area	Spud Latitude	Spud Longitude	TD (MD)	Elevation	Water Depth Unit
48/25-1	1970	Marathon	North Celtic Sea Basin	51° 18' 55.100" N	08° 03' 19.900" W	10941	31	307 ft
50/11-1	1971	Marathon	North Celtic Sea Basin	51° 34' 55.300" N	06° 57' 18.500" W	11906	31	236 ft
49/11-1	1972	Marathon	North Celtic Sea Basin	51° 32' 24.963" N	07° 51' 27.106" W	11967	31	267 ft
49/29-1	1973	Marathon	South Celtic Sea Basin	51° 04' 24.839" N	07° 19' 32.232" W	10502	31	319 ft
49/13-1	1974	Marathon	North Celtic Sea Basin	51° 35' 49.463" N	07° 33' 35.689" W	9516	31	260 ft
49/14-1	1974	Marathon	North Celtic Sea Basin	51° 30' 26.605" N	07° 21' 27.280" W	7964	31	261 ft
49/14-2	1975	Marathon	North Celtic Sea Basin	51° 30' 16.351" N	07° 16' 43.754" W	6659	80	265 ft
49/20-1	1975	Marathon	North Celtic Sea Basin	51° 28' 47.042" N	07° 08' 05.755" W	6589	31	258 ft
102/29-1	1977	Conoco	South Celtic Sea Basin	51° 05' 22.01" N	06° 20' 38.47" W	5638	107	346 ft
49/17-1y	1979	Marathon	North Celtic Sea Basin	51° 24' 18.769" N	07° 41' 49.880" W	8528	82	279 ft
50/12-2A	1981	BP	North Celtic Sea Basin	51° 39' 15.334" N	06° 47' 13.319" W	10165	89	243 ft
49/9-1	1983	Gulf	North Celtic Sea Basin	51° 42' 22.110" N	07° 22' 38.960" W	9239	85	249 ft
49/9-2	1983	Gulf	North Celtic Sea Basin	51° 41' 02.250" N	07° 20' 45.940" W	6300	85	256 ft
49/9-3y	1983	Gulf	North Celtic Sea Basin	51° 41' 02.220" N	07° 20' 45.820" W	8550	85	250 ft
49/19-1	1984	Marathon	North Celtic Sea Basin	51° 22' 52.887" N	07° 21' 50.208" W	11820	95	284 ft
49/14-3	1985	Esso	North Celtic Sea Basin	51° 37' 57.900" N	07° 19' 32.190" W	11715	85	254 ft
49/15-1	1985	Esso	North Celtic Sea Basin	51° 39' 31.460" N	07° 03' 35.190" W	7000	85	249 ft
49/13-2	1986	Marathon	North Celtic Sea Basin	51° 39' 46.760" N	07° 26' 26.230" W	5274	84	263 ft
49/9-4	1987	BP	North Celtic Sea Basin	51° 40' 16.720" N	07° 23' 03.580" W	6844	85	246 ft
49/9-5	1989	BP	North Celtic Sea Basin	51° 41' 27.760" N	07° 17' 32.790" W	5971	85	249 ft
49/9-6,6z	2000	Providence	North Celtic Sea Basin	51° 40' 51.443" N	07° 20' 27.924" W	6866	83	253 ft

Predator has commenced an agreed work programme on LO16/30. With respect to the Middle Wealden, based on well correlation of the gross thickness of reservoirs and top seal and a more detailed analysis of fault patterns and fault throws, Predator has concluded that there is an unacceptably high risk of cross fault leakage and spill over to fault compartments that may not have strike closure to the ESE. For this reason the Middle Wealden is no longer considered a viable objective in the licence area. However a decision was taken by Predator to re-examine the oil potential of the basal Lower Wealden and Upper Purbeck reservoirs.

The ongoing work programme has:

- confirmed that the Late Bathonian to Callovian reservoir sands encountered in 49/19-1 are indeed gas-bearing based on petrophysical evaluation by NuTech and on the basis of correlation of the RFT pressure data, wireline logs, core descriptions and mud log data from 49/14-3;
- improved correlation of the Late Bathonian to Oxfordian section and identified 3 distinct reservoir intervals;
- produced a Conceptual Gas Field Development Study for the basal Upper Jurassic and Late Bathonian gas-bearing reservoirs discovered in the 49/19-1 well by Marathon;
- investigated the feasibility of re-entering and testing 49/19-1 over the Upper Jurassic and Late Bathonian gas-bearing reservoirs.

3.4 Ram Head 49/9-1 Middle to Late Jurassic Gas Prospect

It has been recognised by different operators that the area within LO 16/30 is prospective for gas based on 49/14-1 which tested gas in the Upper Wealden and 49/19-1 which logged but never tested gas in the Middle and Upper Jurassic.

Well 49/9-1 intersected a major fault near the base of the Upper Jurassic above the Bathonian Oolite. The gas effect in the overpressured Upper Jurassic section can be clearly seen on the density, sonic and acoustic impedance well logs for 49/19-1. Reservoirs at the base Upper Jurassic and Bathonian Oolite were found deeper than predicted. Subsequent to burial they appear to have undergone intense burial diagenesis with pressure solution and recrystallisation of quartz grains. Proximity to the major fault resulted in calcite-filled fractures and quartz recrystallization. While sonic-log porosities of up to 6.5% were found in well 49/19-1, core-derived porosities are much lower at 3%. However the core was not acquired in the best developed reservoir interval. Correlation with well 49/14-3, 28 km to the northeast, indicates that 150 feet of potential gross reservoir has been cut out by faulting in 49/19-1. Additional sections are likely lost at the Bathonian Unconformity. Gas shows were encountered in well 49/14-3 at base Upper Jurassic and top Bathonian. The sands had moderate porosity of about10 % despite the significant depths of burial (>11,300 ft). The Bathonian Oolite also appears thicker in well 49/14-3.

No oil shows or significant fluorescence were recorded over the reservoir interval in 49/19-1 but dry gas shows of up to 10,000 ppm C1 were observed on the gas chromatograph. Due to overpressure in the shales high mud weights of 12.8 pounds per gallon were used while drilling the reservoir section of 49/19-1. The wireline resistivity log response indicates poor formation permeability. This was confirmed by core analysis on plugs from core 1 and 2 that had poor permeability. However the wireline neutron-density log showed a gas effect over a gross interval of 270 ft with about 80ft of potentially productive sand. This was not tested at the time in 1984 because there was no commercial incentive. The Kinsale Head Gas Field fully catered for the Irish gas demand and there were no interconnectors with the UK for export.

Basal Upper Jurassic and Late Bathonian oolite appears fractured in core observation and dipmeter records according to Marathon documentation. Cores show calcite infill of many fractures and neutron logs suggest slightly higher porosity readings compared to the sonic log, although the neutron log may be reading fracture porosity, depending on downhole conditions. Between 11,385 and 11,415 feet there is a separation of shallow- and deep-reading resistivity logs, suggesting some mud invasion and the development of permeability in this section. Further petrophysical investigation of this section is required using reprocessed wireline logs and core data in order to better understand pore volume and fracture connectivity.

Using Marathon's original investigation, log interpretation, gas chromatograph and density-neutron crossover analysis, a gas column is indicated in both upthrown and downthrown basal Upper Jurassic and Bathonian oolite reservoirs either side of the major fault in well 49/19-1. This confirms the Marathon-defined "Central" and "Southern" structural components, both charged with gas and without an effective fault seal. The potential gas column could reach 400 feet, with Bathonian and Callovian-Oxfordian reservoirs charged from the Lias in the dry gas window.

The anticline in well 49/19-1 has potential to be highly fractured at base Upper Jurassic and within Bathonian Oolite, indicated by a thick sequence of less competent Lias shales beneath the reservoir section. Prior mapping by Marathon defined the anticlinal feature to cover 30,000 acres or 121.4 km2, with a maximum vertical relief of 1,000 feet (305 m). This was later updated to 123 km2 areal extent by Fastnet at a higher top Middle Purbeck level.

NuTech was contracted to carry out a detailed petrophysical evaluation using Shale Vision and Thin Bed Vision Analysis with Fracture Intensity Vision over the Middle to Late Jurassic high permeability units in 49/19-1. The

analysis has highlighted reservoir "sweet spots" with average permeability of 56 mD. A summary of the pay intervals identified by NuTech is as follows:

- The interval from 11050 to 11100 feet is sandstone with 15 feet of net pay. The characteristics of this interval are, average porosity of 8.5%, average water saturation of 32.1%, average permeability of 2 millidarcies, cumulative hydrocarbon pore volume of 0.9 porosity-feet, and 29.5 cumulative millidarcy-feet. This interval is expected to produce hydrocarbon at a low to fair rate.
- The interval from 11200 to 11400 feet is sandstone with 29 feet of net pay. The characteristics of this interval are, average porosity of 9.9%, average water saturation of 26.6%, average permeability of 56.7 millidarcies, cumulative hydrocarbon pore volume of 2.1 porosity-feet, and 1644.4 cumulative millidarcy-feet. This interval is expected to produce hydrocarbon at a good to low rate.
- The interval from 11400 to 11470 feet is sandstone with 20 feet of net pay. The characteristics of this interval are: average porosity of 9.7%, average water saturation of 25.9%, average permeability of 7.7 millidarcies, cumulative hydrocarbon pore volume of 1.4 porosity-feet, and 153.2 cumulative millidarcy-feet. This interval is expected to produce hydrocarbon at a low to fair rate.

ZONES	INTERVAL FT	PAYFT FT
OXFORDIAN	11050-11100	15
CALLOVIAN	11200-11400	29
LATE BATHONIAN	11400-11470	20

Figure 6 NuTech Log Analysis of 49/19-1 Gas Pay

Esso well 49/14-3 provides information on the reservoir quality of the Middle to Late Jurassic at a burial depth similar to 49/19-1. Comparison between the Middle to Late Jurassic intervals in 49/14-3 (28 kms to the northeast) and 49/19-1 suggests around 150 feet of potential gross reservoir was cut out by faulting (seen on dipmeter at 11,360 and 11,450 feet) and additional section is probably cut-out at the Bathonian unconformity. In 49/14-3 gas shows were seen in the basal Upper Jurassic and the top Bathonian with average porosity of some sands reaching 13% despite their depth (11,300 feet). The reservoir quality observed in 49/14-3 is consistent with the NuTech log analysis results from 49/19-1.

Resource estimates are based on the limited seismic database in the area combined with the regional knowledge of similar plays in the North Celtic Sea Basin. The seismic data were acquired at different times, on different grid orientations with different acquisition parameters making integrated interpretation particularly difficult. Correlation of faults is therefore uncertain. While the quality of some of the seismic lines is locally quite good the quality is highly variable even on the same line. Only one structure is currently recognised with structural maps on four horizons. Three of the maps were produced by Marathon in the 1980s - Top Upper Wealden, Top Purbeckian and Top Middle Jurassic. Base Upper Purbeck and Top Bathonian seismic time maps have been produced by Predator based on the existing 2D seismic. These indicate tilted fault blocks with three way dip closure. The 2015 GeoPartners regional multiclient 2D long offset broadband seismic data are of far superior quality compared to any of the existing vintages of seismic data. Predator's work programme includes re-processing this data to improve event continuity and fault definition which will help to better define the 49/19-1 structure.

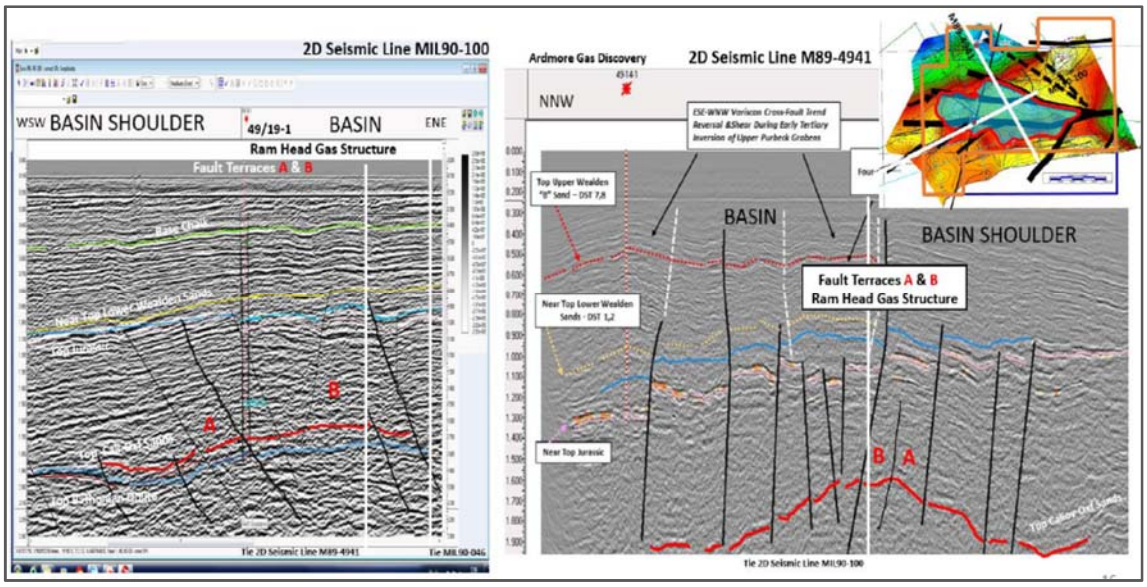


Figure 7 2D Seismic Dip & Strike Lines Ram Head Prospect (Source: Predator)

In summary the LO 16/30 lies on the main hydrocarbon fairway of the North Celtic Sea Basin. The Ram Head Prospect is a mapped closure of about 140 km^2 in the middle of the licence option. It contains the 49/19-1 well that had significant gas shows in Middle to Late Jurassic thin sands reservoirs. Correlation with offset wells suggests that a significant amount of the best reservoir interval is faulted out. Top seal is provided by Late Oxfordian lacustrine shale. The Toarcian source rock has regional distribution and has sourced known hydrocarbon discoveries in the area.

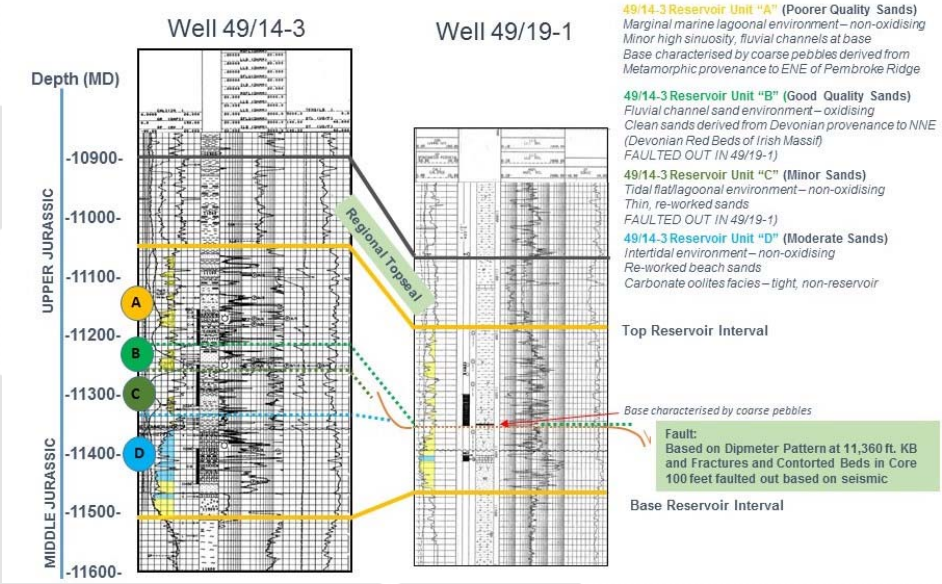


Figure 8 Upper Jurassic Reservoir Correlation 49/19-1 and 49/14-3 showing reservoir faulted out at 49/19-1 (Source: Predator).

3.5 Ram Head Upper Purbeck Oil Sand

A secondary objective of the Marathon 49/19-1 well was the dominantly fluvial sands of the Middle and Upper Purbeck. This interval was oil-bearing, but not tested, in the 50/11-1 Hook Head Structure and had traces of oil, but was unsuccessfully tested, in 49/17-1. In general, these sands are more finer grained than the overlying Wealden sands and have significantly lower porosities and permeabilities relative to the fluvial, braided-stream sands in the Wealden.

Two oil-bearing sequences were encountered in the 49/19-1 well. The upper sequence (below 6100 feet) comprises upward-fining, fluvial channel sands with average log porosities of 15% based on Marathon's petrophysical analysis at the time. The interval was tested (DST 2) and acidized but did not flow, although a "skim" of oil was recovered and analysed in the Geochem Labs oil correlation study (see 49/19-1 released well data). In common with other Lower Purbeck-sourced oils in the North Celtic Sea, the oil is viscous due to a high pour point and significant wax content. Recent work by Predator suggests that the DST 2 sands in 49/19-1 can be correlated with the 48/25-1 and 48/23-1 oil-bearing Upper Purbeck sands underlying the tested Barryroe Basal Wealden sands in 48/24-10z. A petrophysical re-analysis of the DST 2 interval in 49/19-1 was carried out by NuTech. They found that the interval from 6100 to 6460 feet is sandstone with 111 feet of net pay. The characteristics of this interval are, average porosity of 11.7%, average water saturation of 43.9%, average permeability of 37.2 millidarcies, cumulative hydrocarbon pore volume of 7.6 porosity-feet, and 4125.6 cumulative millidarcy-feet. NuTech believe that this interval could produce hydrocarbon at a fair to good rate. They considered that the interval from 6100 ft to 6200 ft has the most potential.

The second zone (below 6280 feet) tested was at the top of the Lower Purbeck and consists of thin-bedded limestones and well cemented sandstones with average log porosities of 12% as calculated by Marathon at the time. The interval did not flow on test, even after stimulation. Neither DST's recovered unequivocal formation water. The log character of the interbedded limestone-sandstone sequence is similar to the interval penetrated at the top of the Lower Purbeck in 48/23-1 in the Seven Heads area, suggesting the potential for lateral continuity of the reservoir unit related to a significant stratigraphic event and/or sequence boundary. Further studies are required to determine the depositional setting of this potential reservoir unit, which reflects the transition from a shale-dominated lacustrine section to a section increasingly dominated by fluvial channel systems.

The structure identified by Predator's most recent seismic interpretation at Top Upper Purbeck Oil Sands level is a subtle rollover to the NE into a shear fault. The closure is based on a re-interpretation of faulting and involves thinly separated sealed oil sands.

3.6 Risks

The geological probability of success (GPoS) or chance of geologic discovery (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018) is assessed at 12% for the Ram Head Middle and Basal Upper Jurassic Gas Sands. There are a number of critical issues. The source of gas in the North Celtic Sea is still unclear. There appears to be some evidence that the gas is a product of biodegradation of previously accumulated oil. While source presence is probable and maturity is possible, the volume of hydrocarbon generated and expelled is a risk given the complicated structural evolution of the NCSB. The quality of the reservoir present remains to be tested. Productivity will be dependent on thin high permeability sands enhanced by fracture porosity. There is an assumption that the best quality reservoir sand is absent in 49/19-1 and will be encountered in the proposed 49/19-2 well. While top seal is proven, cross fault seal against downthrown Upper Jurassic may be a risk. With respect to the trap there are two compartments. One is a tilted fault block and the other a flat lying down faulted rollover into the tilted fault block. Closure is dependent on three way dip closure and fault dependent closure to the north and it is not clear how this could be effective unless the fault plane itself seals. Leakage across faults remains a risk.

Table 2 Prospect Risking

Licence Option 16/30- Ram Head Prospect Risking (%)							
Target	Source Presence	Source Maturity	Reservoir Presence	Migration	Effective Seal	Effective Trap	GPoS
Middle & Basal Upper Jurassic Gas Sands	80%	55%	70%	90%	75%	60%	12%
Upper Purbeck Oil	80%	55%	70%	60%	90%	80%	13%

Hydrocarbon migration relies on early generation, expulsion efficiency and regional migration from synclines. The presence of gas in the 49/19-1 proves gas migration but the structure may not be full to spill. Reprocessing the 2015 multiclient GeoPartners 2D data will further resolve and define the 49/19-1 structure. Re-entry and testing of well 49/19-1 will establish if the Basal Upper and Middle Jurassic are capable of flowing gas at commercial rates and if so what the connected volumes might be given the potential for poor vertical and lateral reservoir communication given the thin sands encountered in the 49/19-1 well.

The geological probability of success (GPoS) or chance of geologic discovery (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018) is assessed at 13% for the Ram Head Purbeck Oil prospect. With respect to Purbeck oil the Purbeck lacustrine facies of the North Celtic Sea Basin has good source rock potential but is only locally mature in some areas. Down dip off structure the Purbeck is likely to be mature. The new structural interpretation at Top Upper Purbeck Oil Sands level is feasible but based on variable quality vintage 2D seismic. Like the Upper Jurassic gas sands the quality of the oil reservoir in the Purbeck prospect is moderate. The high mud weights used in 49/19-1 to balance formation overpressure while drilling may have resulted in formation damage leading to a poor DST unrepresentative of the reservoir quality.

4.0 Resources

Resource estimates are based on the structures mapped on variable quality legacy 2D data. One of the significant risks is on the size of the structures which is based on provisional time mapping. The regional velocity field required for depth mapping is still not well understood.

The Middle to Late Jurassic gas resource at Ram Head is considered to be a prospective resource sufficiently well defined to represent a viable drilling target (see Appendix 2). Low, best and high estimates were calculated in accordance with the 2018 SPE/WPC/AAPG/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System (Table 3). The low, best and high prospective resource estimates are based on the range of parameters discussed here. The NuTech petrophysical evaluation of 49/19-1 identified a maximum net pay in the Middle to Late Jurassic gas reservoir of 64 feet. Correlation between 49/14-3 and 49/19-1 may be possible using a GeoPartners seismic line in order to better define the thickness of the gas bearing Callovian/Oxfordian reservoir interval faulted out in 49/9-1. The Middle to Late Jurassic sandstones record moderate to low wireline log porosities of 6.5% to 10% with core porosity in 49/19-1 as low as 3%. The mapped areas are based on different interpretations of the spill point and fault seal. There are risks to the resource estimates associated with depth conversion where the variable velocity gradient across the structure is not well constrained. The 2015 GeoPartners regional multiclient 2D long offset broadband seismic data are of far superior quality compared to any of the existing vintage 2D data. Predator intends to reprocess GeoPartners data to improve event continuity and fault definition and better map the 49/19-1 structure.

Table 3 Ram Head Prospective Resources

Prospective Resource	Ram	Head
Mid - Late Jurassic Gas	Units	Low
Area	acres	21,763
Net productive thickness	ft	29
Reservoir Bulk Volume	MM ft3	2.749E+10
Porosity	%	6%
Gas Saturation	%	70%
Gas Expansion Factor		0.0029412
GIIP	BCF	392.6
Recovery Factor	%	60%
Resource	BCF	236

Prospective Resource	Ram	Head
Mid - Late Jurassic Gas	Units	Best
Area	acres	33,720
Net productive thickness	ft	49
Reservoir Bulk Volume	MM ft3	7.197E+10
Porosity	%	8%
Gas Saturation	%	72%
Gas Expansion Factor		0.0028571
GIIP	BCF	1451.0
Recovery Factor	%	70%
Resource	BCF	1016

Prospective Resource	Ram	Head
Mid - Late Jurassic Gas	Units	High
Area	acres	53,926
Net productive thickness	ft	64
Reservoir Bulk Volume	MM ft3	1.503E+11
Porosity	%	9%
Gas Saturation	%	75%
Gas Expansion Factor		0.0027778
GIIP	BCF	3653.2
Recovery Factor	%	75%
Resource	BCF	2740

Table 4 Summary Ram Head Prospective Resources

	Gross Attributable			Net Attributable to Predator(50%)				
Prospect Ram Head	Low Estimate (Bscf)	Best Estimate (Bscf)	High Estimate (Bscf)	Low Estimate (Bscf)	Best Estimate (Bscf)	High Estimate (Bscf)	Risk Factor (%)	Operator
Mid - Late Jurassic Gas	236	1016	2740	118	508	1370	12%	Predator

The Purbeck Oil resource at Ram Head is considered to be a contingent resource based on the view that the poor result of DST2 in 49/19-1 was due to formation damage caused by high mud weights required to balance formation overpressure while drilling. The resource is still under evaluation and requires significant further appraisal to clarify the potential for development. While 3D seismic is required to de-risk the structure, and the presence of waxy oil and the thin-bedded nature of the reservoirs will be challenges for a commercial development, the potential opportunity should be recognised. There is no appropriate analogue producing field in the basin at present.

Table 5 Ram Head Contingent Resource

Purbeck Oil Prospect	Units	Low	Best	High
Area	acres	14,384	21,763	34,590
Net productive thickness	ft	34	46	55
Reservoir Bulk Volume	MM ft3	3794097576	7.77E+09	1.4759E+10
Porosity	%	15%	16%	17%
Oil Saturation	%	68%	70%	72%
Formation Volume Factor		1.2	1.1	1.1
STOIIP	MMBbls	321	757	1644
Recovery Factor	%	20%	25%	30%
Resource	MMBbls	64.2	189.2	493.2

Prospect	Gross Attributable			Net Attributable to Predator(50%)				
Ram Head	Low Estimate (MMBbls)	Best Estimate (MMBbls)	High Estimate (MMBbls)	Low Estimate (MMBbls)	Best Estimate (MMBbls)	High Estimate (MMBbls)	Risk Factor (%)	Operator
Upper Purbeck Oil	64	189	493	32	95	247	Premature	Predator

The risk factor for contingent resources means chance of development or probability that the volumes will be commercially extracted (SPE, WPC, AAPG, SPEE, SEG, SPWLA, EAGE, June 2018). The evaluation of the Ram Head Purbeck oil resource is incomplete and therefore it is premature to clearly define the ultimate chance of commerciality.

5.0 Infrastructure and Environmental Issues

5.1 Conceptual Development Plan

The development option proposed for the Middle to Late Jurassic gas resource at Ram Head is a subsea tie in to Inch Terminal and the associated pipeline infrastructure. In the Celtic Sea, subsea installations connect the Southwest Kinsale field to Kinsale Platform Bravo, while the Seven Heads and Ballycotton Fields, in addition to Platform Bravo, are connected to Platform Alpha. At platform Alpha, processing of produced methane occurs - as Kinsale gas is exceptionally pure, only water separation and dehydration is required. In turn, Platform Alpha is connected to Inch Terminal via a single 50 km 12 inch pipeline to Inch Terminal onshore, which odorizes and meters gas when added to the Gas Networks Ireland grid. Up until recently, Southwest Kinsale could be reverse-flowed for seasonal gas storage.

This development option offers a connection to an established route to market with onward pipelines into the onshore grid with the onshore planning issues resolved. With Kinsale Head and associated satellite fields approaching end-of-life, and Southwest Kinsale in blow-down, there is currently excess infrastructure capacity in the area. This assumes no plans for decommissioning of the Inch Terminal by PSE Kinsale Energy Ltd., and no other development in the area coming on stream before Ram Head.

Predator commissioned a Conceptual Ram Head Gas Field Development integrated study including gas reservoir performance, gas well hydraulic performance, hydraulics of pipeline to the nearest platform and potential gas

compression requirements. The study showed that the Ram Head Gas Field can be developed with a minimum number of 10 wells completed in 3 gas zones. It is expected that the gas will most likely be produced by Depletion Drive with an Ultimate Gas Recovery of 96%, in production period of 59.3 years. The effect of potential water influx in gas zones reduces the Ultimate Gas Recovery to 55% that may be produced in 33.9 years. The initial plateau gas production rate by 10 Production wells is estimated to be 400 MMscfD. The study also showed that the reservoir pressure is sufficient to deliver gas to the nearest platform at 35psia and hence, gas compression will not be required. The risk of water influx will need to be modelled and the risk of vertical and lateral reservoir communication needs to be assessed.

6.0 Special Factors

6.1 Country Overview

Ireland is politically stable and close to the European gas market. Ireland has a well-developed gas pipeline infrastructure, with good connections from the UK, which itself is well connected by pipeline and LNG import facilities to and from Continental Europe and further afield (**Figure 13**). The potential impact on Irish gas supply as a result of the UK exiting the European Union is regarded as low, as the Treaties covering the two gas Interconnectors between Great Britain and Ireland that were signed in 1993 (IC1) and 2004 (IC2) in effect guarantee that any shortage of gas in GB would be treated equally with Ireland.

In 2017, overall energy use in Ireland increased by 0.5%, while the economy grew by 7.2% when measured by GNP and by 3.0% when measured by modified gross national income (GNI*). The share of natural gas in final consumption in 2017 amounted to 15%. It has increased its share of the market slowly over the last number of years.

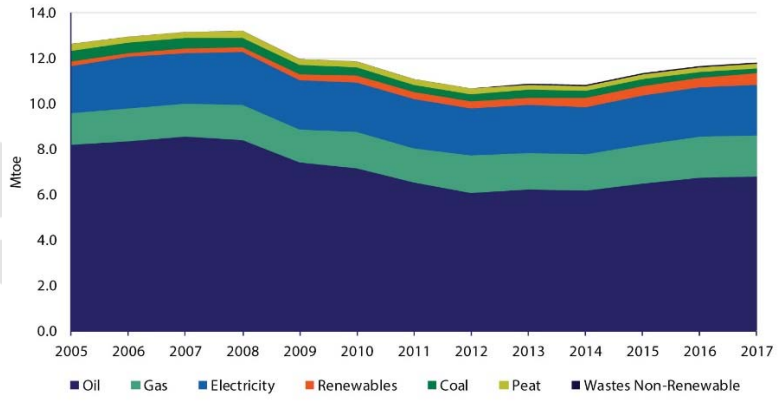


Figure 9 Total final energy consumption by fuel (SEAI 2018)

Moreover, the share of natural gas for electricity generation has increased significantly in recent years and now accounts for over 50%.

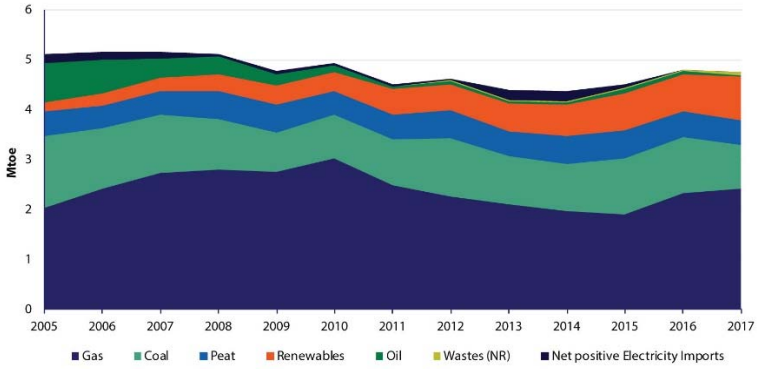


Figure 10 Primary fuel mix for electricity gneration (SEAI 2018)

Imports of natural gas have increased since production from the Kinsale Gas Field started to fall in 1995. Demand peaked in 2010 and fell in the next few years as a result of a fall in economic activity following the global financial crisis. However, this reversed in 2016 and natural gas demand has risen since then. Natural gas production reached the highest level ever, as a result of the Corrib gas field coming on stream in late 2015 and increasing production in 2016 & 2017. Total gas production increased by 1.7% in 2017, when compared with the previous year. As a result, imports of natural gas fell sharply in 2016 & 2017.

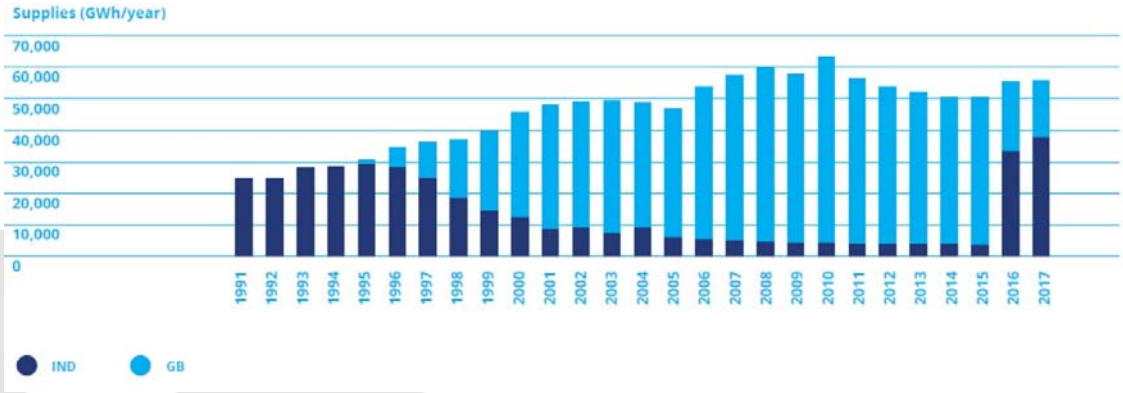


Figure 11 Indigenous and GB gas supplies (GNI 2018)

In the median demand scenario annual Republic of Ireland gas demand is expected to grow by 23.7% between 2017/18 and 2026/27 with growth of 6.7% and 36.8% forecast in the low and high demand scenarios respectively over the same horizon (Figure 12).

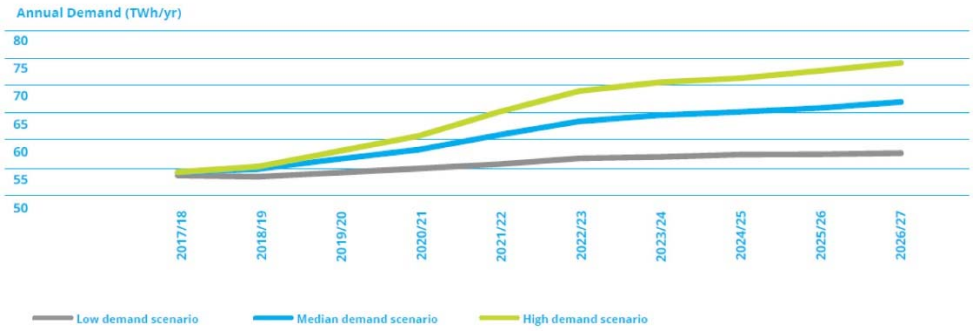


Figure 12 Total annual ROI gas demand (GNI 2018)

The level of production from the Corrib Gas Field is expected to taper off significantly in the next couple of years providing spare infrastructure capacity from the offshore area.

Table 6 Corrib Forecast Maximum Daily Supply (GNI 2018)

	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Daily Supply (mscm/d)	9.91	8.13	7.7	7.44	6.01	4.91	4.25	3.65	3.28	2.86
Daily Supply (GWh/d)	103.8	85.1	80.6	77.9	62.9	51.4	44.5	38.2	34.3	30.0

The Corrib Gas Field, together with marginal supplies from Kinsale Head supplied approximately 67% of annual system demands in 2017. However, by 2026/27 Corrib gas supply will have declined to less than one third of initial peak production levels.

But energy security of supply as Corrib production declines in the medium term will continue to depend on the Moffat entry point if new sources of indigenous gas are not discovered and brought on production. Nevertheless Gas Networks Ireland is investigating physical reverse flow at Moffat from the Republic of Ireland to Great Britain and Northern Ireland to increase market integration in the face of high swings in daily gas demand caused in part by increased wind generation.

In summary there is a strong indigenous market for gas with the potential to export to GB in the event of surplus supplies if large gas discoveries are made.

The nearby Kinsale Head gas field is nearing the end of its life and decommissioning plans are being prepared. The Southwest Kinsale storage facility commenced blowdown of cushion gas in 2016 and overall production is expected to cease in 2021. There is potential for Ram Head to reuse some of the Kinsale Head infrastructure, in particular the offshore pipeline, which is 40 kms from Ram Head and the Inch entry point to the GNI transmission system. Utilisation of the latter would obviate the necessity of constructing a new landfall, which would likely to be time consuming and expensive.

The fiscal regime is considered to be appropriate for the stage of development of the country's exploration history and reflects the relatively high risk associated with exploration in Ireland, when compared for example with the UK and Norway. The current terms, which were modified in 2014, include a Petroleum Production Tax (PPT) to apply at a variable rate of 0% to 40% linked to profitability of discoveries. This would result in a maximum rate of 55% applying in the case of new licences. There is a minimum annual PPT payment of 5% of the gross revenues of a field

once production has commenced. The PPT is permitted as a deduction from Corporation Tax applying to petroleum production, which is 25%. Expenditures are subject to 100% write-off. Thus, given the low/medium cost development scenarios for a tie back to the Inch Terminal infrastructure, any commercial development of a small/medium sized field should prove to be commercially attractive.

Figure 13 Overview of Irish Gas Transmission System (Source GNI 2018)

It should be noted that a risk to hydrocarbon development in Ireland exists through a proposed new law. The private members Petroleum and Other Minerals Development (Amendment) (Climate Emergency Measures) Bill 2018 is at Committee Stage in the Oireachtas (Irish Parliament). It includes a proposal that would have the effect of preventing a Minister from issuing licences, undertakings or leases to companies wishing to develop hydrocarbon discoveries offshore Ireland if certain national and global environmental considerations are not met. Under Government Standing Orders the Minister for the Department of Communications, Climate Action and Environment (DCCAE) halted the legislation on the grounds that the State would face significant financial risks as a result of the Bill.

On 20th September 2019 the Climate Change Advisory Council (CCAC) advised the DCCAE that the exploration for, and recovery of new offshore oil reserves is not compatible with a low carbon transition. However, the CCAC further advised that natural gas has been identified internationally as an important transition fuel, as the global energy system switches from carbon intensive fossil fuels to low carbon and renewable systems on the way to complete decarbonisation. On 23rd September at the United Nations Climate Action Summit An Taoiseach (the Irish Prime Minister) said that he accepted the advice of the CCAC and that Ireland will now act on it. The Minister for

DCCAE will bring a memo to government to set out the next steps. It is possible that positive attention may now be focussed on Celtic Sea and Slyne Basin gas prospects.

Appendix 1

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Appendix 2

Petroleum Reserve Definitions

This Glossary provides high-level definitions of terms used in reserves evaluations by the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).

DEFINITIONS

Reserves are those quantities of petroleum[1] which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

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

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

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

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

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

PROVED RESERVES

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

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

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

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

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

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

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

UNPROVED RESERVES

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

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

PROBABLE RESERVES

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

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when(a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favourable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behaviour in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

POSSIBLE RESERVES

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

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

RESERVE STATUS CATEGORIES

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

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

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

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

Behind-pipe reserves are expected to be recovered from zones in existing wells, which will required additional completion work or future recompletion prior to the start of production.

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

The following Glossary provides high-level definitions of terms used in resources evaluations by the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).

As with unproved (i.e. probable and possible) reserves, the intent of the SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of quantities classified as resources. Such disclosure is left to the discretion of the countries or companies involved. Estimates derived under these definitions rely on the integrity, skill, and judgement of the evaluator and are affected by the geological complexity, stage of exploration or development, degree of depletion of the reservoirs, and amount of available data. Use of the definitions should sharpen the distinction between various classifications and provide more consistent resources reporting.

DEFINITIONS

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

TOTAL PETROLEUM-INITIALLY-IN-PLACE

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

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

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

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

RESERVES

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

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

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

CONTINGENT RESOURCES

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

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

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

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

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

PROSPECTIVE RESOURCES

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

ESTIMATED ULTIMATE RECOVERY

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

AGGREGATION

Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with

their classification. In particular, there may be a significant risk that accumulations containing Contingent Resources or Prospective Resources will not achieve commercial production.

RANGE OF UNCERTAINTY

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

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

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

RESOURCES CLASSIFICATION SYSTEM

Graphical Representation

Figure 2.1 is a graphical representation of the definitions from the Petroleum Resources Management System jointly published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysists and the European Association of Geoscientists and Engineers as amended June 2018 (PRMS 2018).. The horizontal axis represents the range of uncertainty in the estimated potentially recoverable volume for an accumulation, whereas the vertical axis represents the level of status/maturity of the accumulation. Many organizations choose to further sub-divide each resource category using the vertical axis to classify accumulations on the basis of the commercial decisions required to move an accumulation towards production.

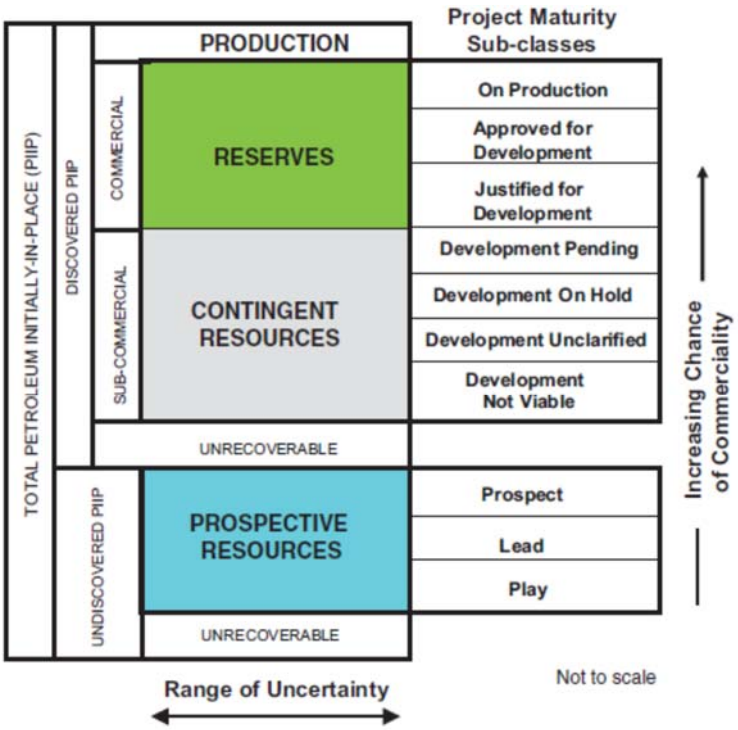

Figure 2.1—Sub-classes based on project maturity

As indicated in Figure 2.1, the Low, Best and High Estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved, Proved plus Probable and Proved plus Probable plus Possible, respectively. While there may be a significant risk that sub-commercial or undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable volumes independently of such a risk.

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

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

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