THIS DOCUMENT AND ANY ACCOMPANYING DOCUMENTS ARE IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or as to the action you should take, you are recommended to seek your own personal financial advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser authorised under the Financial Services and Markets Act 2000 (as amended) if you are in the United Kingdom or, if not, from another authorised independent financial adviser.

If you have sold or transferred all of your Ordinary Shares you should send this document, along with the Form of Proxy, at once to the purchaser or transferee or stockholder or other agent through whom the sale or transfer was effected for transmission to the purchaser or transferee. However, the foregoing documents must not be distributed, forwarded or transmitted in or into any Restricted Jurisdiction. If you have sold or transferred only part of your holding of Ordinary Shares you should retain these documents and consult the stockbroker, bank or other agent through whom the sale or transfer was effected.

This document, which comprises an AIM Admission Document drawn up in accordance with the AIM Rules, has been issued in connection with the application for admission to trading of the Company's Ordinary Shares on AIM. This document contains no offer to the public within the meaning of section 102B of FSMA, the Act or otherwise. Accordingly, this document does not comprise a prospectus within the meaning of section 85 of FSMA and has not been drawn up in accordance with the Prospectus Rules or approved by or filed with the Financial Conduct Authority or any other competent authority.

AIM is a market designed primarily for emerging or smaller companies to which a higher investment risk tends to be attached than to larger or more established companies. AIM securities are not admitted to the Official List of the UK Listing Authority. A prospective investor should be aware of the risks of investing in such companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser. Each AIM company is required pursuant to the AIM Rules for Companies to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Admission in the form set out in Schedule Two to the AIM Rules for Nominated Advisers. The London Stock Exchange has not itself examined or approved the contents of this document. It is emphasised that no application is being made for admission of these securities to the Official List of the UK Listing Authority.

The Company and its Directors (whose names and functions appear in paragraph 12 of Part I (*Letter from the Chairman of Serica*)) accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and contains no omission likely to affect its import.

You should read the whole of this document and any documents incorporated herein by reference. In particular, your attention is drawn to the factors described in Part IV (*Risk Factors*) and the letter from your Chairman which is set out in Part I (*Letter from the Chairman of Serica*) and which contains a recommendation from your Board that you vote in favour of the Resolution to be proposed at the General Meeting.

SERICA ENERGY PLC

(Incorporated and registered in England and Wales under the Companies Act 1985 with registered number 05450950)

Proposed acquisition of BP interests in the Bruce, Keith and Rhum fields in the North Sea[1]

Admission of the Company's Ordinary Shares to trading on AIM
Notice of General Meeting

Nominated Adviser & Broker

Peel Hunt LLP

The existing Ordinary Shares are admitted to trading on AIM, a market operated by the London Stock Exchange. As the Acquisition constitutes a reverse takeover under the AIM Rules, admission of the Ordinary Shares will be cancelled on completion of the Acquisition. Application will be made for the Company's Ordinary Shares to be re-admitted to trading on AIM. It is expected that Admission will become effective and that dealings in the Ordinary Shares will commence on AIM at a date to be determined in mid-2018. No application has been made or is currently intended to be made for the existing Ordinary Shares to be admitted to listing or trading on any other exchange.

Peel Hunt LLP ("**Peel Hunt**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as nominated adviser and broker to the Company in connection with the Proposals and will not regard any other person as its client in relation to the Proposals nor will it be responsible to any person other than the Company for providing the protections afforded to its clients or for advising any other person in respect of the Proposals other than the Company. Peel Hunt's responsibilities as the Company's nominated adviser under the AIM Rules are owed solely to the London Stock Exchange and are not owed to the Company or to any Director or to any other person in respect of such person's decision to acquire shares in the Company in reliance on any part of this document. Peel Hunt has not authorised the contents of any part of this document and neither accepts liability for the accuracy of any information or opinions contained in this document nor for the omission of any material information from this document for which the Company and the Directors are responsible. No representation or warranty, express or implied, is made by Peel Hunt as to any of the contents of this document (without limiting the statutory rights of any person to whom this document is issued).

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

Notice convening a general meeting of Serica to be held at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA at 11.00 a.m. on 18 December 2017 is set out at the end of this document. The enclosed Form of Proxy for use at the General Meeting should be completed and returned to Link Asset Services, PXS 1, The Registry, 34 Beckenham Road, Beckenham, Kent BR3 4ZF as soon as possible and to be valid must arrive no later than 11.00 a.m. on 16 December 2017. Completion and return of Forms of Proxy will not preclude Shareholders from attending and voting at the General Meeting should they so wish. Alternatively, eligible Shareholders may use the CREST Proxy Voting Service, details in respect of which are contained in the notice of General Meeting.

Copies of this document will be available free of charge during normal business hours on any weekday (except Saturdays, Sundays and public holidays) from the Company's registered office from the date of this document until the date which is one month from the date of Admission. A copy of this document will also be available from the Company's website – www.serica-energy.com.

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1 BP will retain a 1% interest in the Bruce field.

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IMPORTANT INFORMATION

FORWARD LOOKING STATEMENTS

This document includes statements that are, or may be deemed to be, "forward-looking statements". These forward-looking statements can be identified by the use of forward-looking terminology, including the terms "believes", "envisages", "estimates", "anticipates", "projects", "expects", "intends", "may", "will", "could", "seeks" or "should" or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy plans, objectives, goals, future events or intentions. These forward-looking statements include statements regarding the Company's and the Directors' current intentions, beliefs or expectations concerning, amongst other things, investment strategy, financing strategy, performance, results of operations, financial condition, liquidity, prospects, growth, strategies and the industry in which the Enlarged Group will operate.

By their nature, forward-looking statements involve risks (including unknown 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 an assurance of future performance. The Company's actual performance, results of operations, financial condition, liquidity and dividend policy and the development of the business sector in which the Enlarged Group will operate, may differ materially from those suggested by the forward-looking statements contained in this document. In addition, even if the Company's performance, results of operations, financial condition, liquidity and dividend policy and the development of the industry in which the Enlarged Group will operate, 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.

Prospective investors are advised to read this entire document, including Part IV (*Risk Factors*), for a more complete discussion of the factors that could affect the Company's future performance and the industry in which the Enlarged Group will operate. In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements in this document may or may not occur.

Any forward-looking statements in this document reflect the Company's and the Directors' current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to the matters referred to above. Prospective investors should specifically consider the factors identified in this document which could cause actual results to differ before making an investment decision. Other than in accordance with the Company's obligations under the AIM Rules for Companies, neither the Company nor Peel Hunt undertakes any obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

SOURCES

Save where otherwise specified, information in this document pertaining to the petroleum assets in which the Enlarged Group will be interested is derived from the BKR CPR and Serica CPR which are included in their entirety in Parts V (*Competent Person's Report on the BKR Assets*) and VI (*Competent Person's Report on Serica*). While the information in Parts I (*Letter from the Chairman of Serica*), II (*Further Information on the BKR Assets*) and III (*Further Information on Serica*) provides a summary of certain aspects of the BKR CPR and the Serica CPR, such reports include further details, as well as various assumptions and qualifications and should therefore be read in their entirety.

Various market data and forecasts used in this document have been obtained from independent industry sources. Neither the Company nor Peel Hunt has verified the data, statistics or information obtained from these sources and cannot give any guarantee of the accuracy or completeness of the data. Forecasts and other forward-looking information obtained from these sources are subject to the same qualifications, risks and uncertainties as above.

Various figures and percentages in tables in this document have been rounded and accordingly may not total. Certain financial data has also been rounded. As a result of this rounding, the totals of data presented in this document may vary slightly from the actual arithmetical totals of such data.

All times referred to in this document are, unless otherwise stated, references to London time.

CURRENCIES

Unless otherwise indicated in this document, all references to "**US$**" or "**US dollar**" are to be lawful currency from time to time of the United States and "**£**" or "**pounds sterling**" are to the lawful currency from time to time of the United Kingdom.

RESERVES AND RESOURCES

Unless otherwise stated, references in this document to Reserves are on a 2P basis, to contingent resources are on a 2C basis and to prospective resources are on a "Best" estimate (P50) basis.

Unless otherwise stated, where amounts are expressed on a boe basis, natural gas volumes have been converted to boe at a ratio of 6,000 cubic feet of natural gas to one boe in relation to existing Serica assets and 5,800 cubic feet of natural gas to one boe in relation to the BKR Assets.

OTHER NOTICES

Apart from the responsibilities and liabilities, if any, which may be imposed on Peel Hunt by the FSMA or the AIM Rules, Peel Hunt makes no representation, express or implied, with respect to the accuracy or completeness of any information contained in this document or any other statement made or purported to be made by it or on its behalf, in connection with the Company or the Acquisition. Peel Hunt accepts no responsibility and does not authorise the contents of this document and disclaims any and all liability, whether arising in tort, contract or otherwise (save as referred to above), which it might otherwise have in respect of this document or any such statement.

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The contents of this document should not be construed as legal, business or tax advice. Each Shareholder and prospective investor should consult his, her or its legal adviser, financial adviser or tax adviser for advice. Neither the Company nor Peel Hunt nor any of their respective representatives, are making any representation to any offeree or purchaser or acquirer of Ordinary Shares regarding the legality of an investment in the Ordinary Shares by such offeree or purchaser or acquirer under the laws applicable to such offeree or purchaser or acquirer.

Recipients of this document acknowledge that: (i) they have not relied on Peel Hunt or any of its affiliates in connection with any investigation of the accuracy of any information contained in this document or in connection with their investment decision; and (ii) they have relied only on the information contained in this document. In making an investment decision, each investor must rely on their own examination, analysis and enquiry of the Company, including the merits and risks involved.

No person has been authorised to give any information or make any representations other than those contained in this document and, if given or made, such information or representations must not be relied upon as having been authorised by the Company or by Peel Hunt. Neither the delivery of this document nor any subscription or sale made hereunder 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 in this document is correct as at any time subsequent to its date.

SHARE CAPITAL

Number of Ordinary Shares in issue at date of this document[2]	263,679,039
ISIN number	GB00B0CY5V57
SEDOL number	B0CY5V5

EXPECTED TIMETABLE OF PRINCIPAL EVENTS[3]

Publication of this document	30 November 2017
Latest time and date for receipt of Forms of Proxy	11.00 a.m. on 16 December 2017
General Meeting	11.00 a.m. on 18 December 2017
Completion of the Acquisition	mid-2018

2 The Company also has in issue one A Share of £50,000 at the date of this document.

3 Each of the times and dates set out in the expected timetable of principal events and mentioned throughout this document, the Form of Proxy and any other documents issued in connection with the Proposals, is subject to change at the absolute discretion of the Company. Any such change will be notified to Shareholders by an announcement on a Regulatory Information Service.

DIRECTORS, SECRETARY AND ADVISERS

Directors	Antony Craven Walker (*Executive Chairman*) Mitchell Robert Flegg (*Chief Executive Officer*) Robert Eben Neil Pike (*Senior Independent Non-Executive Director*) Ian Roland Vann (*Independent Non-Executive Director*) *whose business address is at the Company's registered office:* 52 George Street London W1U 7EA United Kingdom
Company website	www.serica-energy.com
Company Secretary	Amanda Bateman AMBA Company Secretarial Services Limited 400 Thames Valley Park Drive Thames Valley Park Reading RG6 1PT United Kingdom
Nominated Adviser and Broker to the Company	Peel Hunt LLP Moor House 120 London Wall London EC2Y 5ET United Kingdom
Solicitors to the Company as to English law	Ashurst LLP Broadwalk House 5 Appold Street London EC2A 2HA United Kingdom Womble Bond Dickinson LLP 13 Albyn Terrace Aberdeen AB10 1YP Scotland
Solicitors to the Company as to Irish law	Eversheds Sutherland One Earlsfort Centre Earlsfort Terrace Dublin 2 Ireland
Solicitors to the Company as to Dutch law	Loyens & Loeff N.V. Fred. Roeskestraat 100 1076 ED Amsterdam The Netherlands
Solicitors to the Company as to Namibian law	Koep & Partners 33 Schanzen Road PO Box 3516 Windhoek Namibia

Solicitors to Peel Hunt as to English law	Berwin Leighton Paisner LLP Adelaide House London Bridge London EC4R 9HA United Kingdom
Auditors and Reporting Accountants	Ernst & Young LLP 1 More London Place London SE1 2AF United Kingdom
Serica Competent Person	Netherland, Sewell & Associates, Inc. Fulbright Tower 1301 McKinney Street Suite 3200 Houston Texas 77010 USA
BKR Assets Competent Person	Ryder Scott Company, L.P. 1100 Louisiana Suite 4600 Houston Texas 77002-5294 USA
Registrar	Link Asset Services The Registry 34 Beckenham Road Beckenham Kent BR3 4ZF United Kingdom
Financial Public Relations Adviser to Serica	Instinctif Partners 65 Gresham Street London EC2Y 7NQ United Kingdom

PART I – LETTER FROM THE CHAIRMAN OF SERICA

SERICA ENERGY PLC

(Incorporated and registered in England and Wales under the Companies Act 1985 with registered number 05450590)

Directors:	*Registered Office:*
Antony Craven Walker (*Executive Chairman*)	52 George Street
Mitchell Robert Flegg (*Chief Executive Officer*)	London W1U 7EA
Robert Eben Neil Pike (*Non-Executive Director*)	
Ian Roland Vann (*Non-Executive Director*)	

30 November 2017

Dear Shareholder,

Proposed acquisition of BP interests in the Bruce, Keith and Rhum fields in the North Sea[4]
Admission of the Company's Ordinary Shares to trading on AIM
and Notice of General Meeting

1. Introduction

On 21 November 2017 the Company announced that it had reached agreement for Serica UK, a wholly owned subsidiary of the Company, to conditionally acquire the BKR Assets from BP. The BKR Assets comprise of BP's interests in the Bruce, Keith and Rhum fields in the North Sea along with associated oil and gas infrastructure. BP is retaining a 1% interest in the Bruce field. Subject to Completion, Serica will also become the operator of the BKR Assets and the Directors anticipate that approximately 110 BP employees will be transferred to Serica. The purchase of the BKR Assets represent a significant step in the evolution of the Company from an exploration and development group with no operating role in producing fields to the operator of major gas fields in the North Sea.

The cash consideration being paid to BP comprises:

(i) an Initial Consideration of £12.8 million payable on Completion, subject to adjustment for working capital;

(ii) a further contingent amount of up to £16 million dependent on the Rhum R3 Well (the third well on the Rhum field) achieving a specified minimum production threshold for 90 days during the first year following completion of the workover of the well, anticipated to take place in 2018;

(iii) an additional contingent consideration of up to £23.1 million in aggregate (payable in three instalments of up to approximately £7.7 million each) in respect of 2019, 2020 and 2021 if the Rhum field production volumes and sales prices meet or exceed certain agreed levels. The amounts payable will be reduced if Rhum field production and the price achieved for sales of Rhum gas do not meet the agreed levels;

(iv) deferred consideration calculated as a percentage (60% in 2018, 50% in 2019 and 40% in each of 2020 and 2021) of the pre-tax net cash flows resulting from BP's interests in the BKR Assets from 2018 through to 2021;

(v) deferred consideration equal to 30% of BP's retained share of future decommissioning costs when due, reduced by the tax relief BP receives on such costs; and

(vi) deferred consideration equal to 90% of Serica's share of the realised value of oil in the Bruce pipeline at the end of field life.

The deferred and contingent cash consideration is expected to be financed from the expected cash flow from the BKR Assets.

BP will retain liability for all the costs of decommissioning facilities including wells existing at Completion relating to the BKR Assets. Serica UK will pay for the costs of decommissioning new facilities.

As part of the Acquisition, Serica UK has entered into product sales agreements with certain BP entities to off-take Serica's share of production of gas, oil and natural gas liquids from the BKR

4 BP will retain a 1% interest in the Bruce field.

Assets on market terms as more fully set out in paragraph 11.1(c) of Part XII (*Additional Information*). In addition, BP Gas has agreed to provide Serica with a prepayment facility of up to £16 million to provide for drawings to cover the cost of gas price hedging instruments which have been purchased by Serica UK in conjunction with signing the Acquisition Agreement and, if required, the Initial Consideration.

Upon Completion, the Enlarged Group will have a diversified portfolio of production, development and exploration assets in the North Sea and exploration assets also offshore Ireland and offshore Namibia. Upon Completion, the Enlarged Group will have approximately 50 mmboe of net 2P Reserves based on projected Reserves as of 1 January 2018 and approximately 13.6 mmboe of net 2C contingent resources in the UK and approximately 281 mmboe of net Best Estimate prospective resources in the UK and Ireland.[5]

The principal near term work programme includes the application of well stimulation techniques on certain of the Bruce field wells to improve production and a well intervention on the Rhum R3 Well to remove hydrates and wireline equipment which are currently preventing production from the well.

The Enlarged Group will be led by myself (as Executive Chairman). Mitch Flegg joined the Board as Chief Executive Officer on 21 November 2017. Prior to Completion, the Board is expected to be strengthened with the appointment of two further independent non-executive directors. To provide for a full operating capacity, all current offshore and directly related onshore personnel relating to the BKR Assets are anticipated to transfer across to the Enlarged Group. This will comprise a highly skilled team of approximately 110 personnel with strong operating capabilities to manage the BKR Assets as well as to deliver on the Enlarged Group's work programme. Further details of the Directors and management of the Enlarged Group are set out at paragraph 12 of this Part I (*Letter from the Chairman of Serica*).

The Acquisition includes an ownership stake and operatorship of the Rhum field, which is owned 50% by Iranian Oil Company (UK) Limited, a subsidiary of the National Iranian Oil Company. US primary sanctions imposed against Iran apply to all US persons. In order to ensure that Serica is not encumbered in its future operations by his presence as a director, Jeffrey Harris, who has served on the Board since 2012 and is a US citizen, has stepped down from the Board effective 20 November 2017. GRG UK Oil LLC, an entity controlled by Jeffrey Harris, remains a Shareholder of Serica. The Board wishes to record its gratitude to Jeffrey who has made a significant contribution to the success of the Company during his tenure as a director.

The Acquisition constitutes a reverse takeover under the AIM Rules for Companies. As such, the Acquisition is subject to the approval of Shareholders, which is being sought at the General Meeting to be held at 11.00 a.m. on 18 December 2017, notice of which is set out at the end of this document. The Acquisition is also conditional on various consents and approvals being obtained including consent to the Acquisition from the Oil & Gas Authority, the approval of BP's partners to the transfer of operatorship to Serica as well as on the re-admission of the Company's Ordinary Shares to trading on AIM occurring. The satisfaction of all the conditions will take time, so the Acquisition is not expected to complete until mid-2018. Subject to all the conditions to the Acquisition being satisfied, the admission of the Ordinary Shares to trading on AIM will be cancelled, and the Ordinary Shares will be re-admitted to trading on AIM.

The purpose of this document is to set out the background to and reasons for the Proposals, to provide information on the Proposals, to explain why your Board believes that the Proposals are in the best interests of the Company and to recommend that Shareholders vote in favour of the Resolution to be proposed at the General Meeting which is being convened for 18 December 2017, notice of which is set out at the end of this document.

2. Background to, reasons for and benefits of the Acquisition

In June 2015, Serica completed the acquisition of an 18% interest in the Erskine field located in the Central North Sea Area of the UKCS. Since that time Serica has benefited from strong cash flow generation as production efficiencies at the Erskine field increased and operating costs reduced. This has been reflected in a five-fold increase in the Company's market capitalisation since the time of the acquisition. However, the Company has remained dependent on a single field and the continuing performance of the downstream processing and transportation systems for the delivery of its sole source of production to the market.

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5 The Reserves and resources figures set out in this paragraph derive from the BKR CPR and the Serica CPR and are shown on an equivalent unit basis where natural gas is converted to oil equivalent.

It has been the Board's stated objective to seek to diversify this risk and, by doing so, to provide the platform for future growth. The Acquisition meets these criteria and will establish Serica as a leading British independent oil and gas company with the scale, balance sheet and operating capability to grow and prosper in the rapidly changing upstream oil and gas environment. As well as helping to establish Serica as a technically capable and robustly financed upstream operator with the experience, expertise, assets and finances to create new opportunities for growth the Directors believe the Acquisition provides the following benefits:

Diversification of production streams and export routes

The purchase of the BKR Assets will represent a significant step in the evolution of the Company from an exploration and development group with no current operating role in producing fields to the operator of major gas fields in the North Sea. Serica will no longer be dependent on the Erskine field as its sole source of production. The Company's share of Erskine field production (approximately 2,800 boepd net in the first half of 2017) will be materially enhanced by the Company's share of Bruce, Keith and Rhum field production (approximately 18,500 boepd net in the first half of 2017). The Acquisition will also provide Serica with access to the Frigg gas pipeline through which Bruce, Keith and Rhum field gas is exported in addition to the Central Area Transmission System pipeline through which Erskine field gas is exported. The condensate from each of these fields is exported through the Forties Pipeline System.

Addition of new Reserves

The net 2P Reserves attributable to the BKR Assets as at 1 January 2018 are projected to amount to approximately 47 mmboe. These Reserves will provide a significant addition to the remaining net approximately 3 mmboe 2P Reserves attributable to Serica's share of the Erskine field as at 1 January 2018 (these estimates are derived from the BKR CPR and the Serica CPR, after providing for estimated production in the second half of 2017, and are shown on an equivalent unit basis where natural gas is converted to oil equivalent).

The Acquisition is structured to control risk and minimise Shareholder dilution

The Acquisition has been structured primarily on a deferred/contingent consideration basis, leaving Serica with relatively small Initial Consideration of £12.8 million which is expected to be funded from cash flow from the BKR Assets during the period from 1 January 2018 to Completion but which can also be funded through the Prepayment Facility provided by BP Gas. The Directors expect to be able to meet the future deferred and contingent cash consideration payable from the net cash flows from the BKR Assets following Completion with the level of future payments linked to the performance of the BKR Assets thereby allowing both Serica and BP to share the benefits of improving field recoveries and production efficiencies.

Maintains the Company's balance sheet strength

The consideration structure with the emphasis on future payments related to performance will assist Serica in maintaining its current balance sheet strength with net cash resources and limited borrowings. The Enlarged Group's only borrowings at Completion are expected to be drawings under the Prepayment Facility provided by BP Gas. In addition, the arrangements on decommissioning, under which BP is retaining all of the decommissioning liabilities relating to the BKR Assets existing at the point of Completion, assists Serica in maintaining financial capability to support its future operations. The Directors believe that a strong balance sheet supported by cash flows from the BKR Assets can be used to invest in the BKR Assets and will assist the Company in working with its new field partners to achieve the objective of adding recoverable Reserves, extending field life and pursuing further growth opportunities.

The Acquisition is expected to be cash flow and value accretive

The Acquisition is expected to be immediately cash flow and value accretive post-Completion. Based on production rates in the first half of 2017, Serica's net production is projected to increase seven-fold as a result of the Acquisition. Pro forma net 2P Reserves at 1 January 2018 are anticipated to increase 16-fold to approximately 50 mmboe.

Management input through operatorship

Serica UK is development operator of the Columbus field in the Central North Sea in respect of which the Directors are aiming to submit a Field Development Plan by mid-2018. Subject to Completion, Serica UK will become production operator of the BKR Assets and will be able to complement its skill sets and its management experience with those of the existing BP staff who will become an integral and valuable part of Serica's team. The Directors believe that this combination of entrepreneurial skills and operating expertise will enable Serica to build on BP's achievements and deliver the full potential of the BKR Assets through investment, operational efficiencies and focus whilst also meeting the OGA's targets of Maximising Economic Recovery.

Efficient use of tax pool

Serica is expected to be able to optimise the value of its pool of carried forward tax allowances by accelerating their use against taxable profits from the Bruce, Keith and Rhum fields. The value of the pool stood at approximately US$165 million at 1 January 2017 and a portion will have been used against taxable profits from the Erskine field prior to Completion.

Limited exposure to commodity prices

The BKR Assets are predominantly gas assets and, as such, have limited exposure to international oil price movements. Under the Product Sales Agreements, Serica UK will sell all of its future production from the BKR Assets to BP entities and has hedged 60% of its retained share of gas production for 2018, 60% for 2019 and 40% for the first half of 2020 at a floor price of 35 pence per therm. The cost of these hedging instruments has been drawn under the Prepayment Facility. Gas price hedging mitigates risk for Serica in relation to the Acquisition following Completion.

Increased scale

The Directors believe that scale is important in the international oil and gas industry. The Acquisition will increase Serica's prominence and profile improving its ability to attract new investment funding when required. The diversification of Serica's assets through the Acquisition and limited borrowings places the Company in a strong position to grow both organically through application of technology and operational efficiencies and inorganically through further acquisitions. The Acquisition is expected to place Serica as the third largest quoted European independent upstream oil and gas company measured by UK production.

3. Summary of the Enlarged Group's Reserves and Resources

The Enlarged Group's Reserves and resources are summarised in the below tables, which are extracted from the BKR CPR and Serica CPR, which can be found in their entirety in Parts V (*Competent Person's Report on the BKR Assets*) and VI (*Competent Person's Report on Serica*) respectively.

Summary of estimated net Reserves attributable to Serica's interest in the Erskine field (as at 30 June 2017)

	Total 1P	Total 2P	Total 3P
Net Remaining Reserves			
Oil (mbbl)	820.7	1,498.5	2,323.1
NGL (mbbl)	107.6	195.3	301.3
Gas (mmcf)	5,414.8	9,825.5	15,163.9

Source: Serica CPR, Technical Discussion, page 3

Summary of estimated net Reserves to the BKR Assets (as at 1 June 2017)

	Total 1P	Total 2P	Total 3P
Net Remaining Reserves			
Oil and liquids (mbbl)	3,394	4,994	5,430
Gas (mmcf)	171,008	264,258	306,686

Source: BKR CPR, page 3.

Summary of net unrisked 2C contingent resources[1] attributable to Serica's interest in the Columbus Field (as at 30 June 2017)

Field	Operator	Risk Factor[2] (%)	2C Contingent Resources Oil (mbbl)	2C Contingent Resources Gas (mmcf)
Columbus Field	Serica Energy (UK) Limited	85	1,396.9	31,766.6

Source: Serica CPR, Technical Discussion, page 5.

Notes:

(1) These volumes represent only the portions of the reservoirs that lie within the boundary of the lease area.

(2) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this table, the risk factor for the contingent resources refers to the PRMS term "chance of development".

Summary of net contingent resources attributable to the BKR Assets (as at 1 June 2017)

Field	Risk Factor (%)	2C Contingent Resources Oil (mbbl)	2C Contingent Resources Gas (mmcf)
Bruce Field (BP 36% working interest)	50	3	76
Keith Field (BP 34.83% working interest)	50	2	6
Rhum Field (BP 50% working interest)	50	218	38,719

Source: BKR CPR, page 7.

Summary of net unrisked Best Estimate prospective resources[1] attributable to Serica's interest (as of 30 June 2017)

Region/ Prospect	Oil (mmbbl)	Gas (bcf)	Risk Factor (%)[2]
Irish Waters in the Atlantic Ocean			
Achill	0.0	252.7	26
Bandon South	0.0	26.9	26
Boyne Sherwood	0.0	180.2	26
Boyne Suisnish	20.1	5.5	20
Liffey Sherwood	0.0	180.4	26
Liffey Suisnish	128.2	34.0	20
UK Sector of the Central North Sea			
Rowallan Pentland	1.3	17.8	22
Rowallan Triassic	4.9	63.4	22
Total[3]	154.6	760.8	—

Source: Serica CPR, Technical Discussion, page 8.

Notes:

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or licence areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of the table above, the risk factor for the prospective resources refers to the PRMS term "chance of discovery".

(3) Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

In view of the undrilled nature of Serica's licences in the Irish Rockall basin and in Namibia, there being no Reserves discovered to-date on these licences and there being no immediate plans to drill these licences without introducing partners to share costs, the Company has not undertaken a competent person's report in respect of these licences.

4. Background information on the BKR assets

The BKR Assets comprise of a 36% interest in the Bruce field, a 34.83% interest in the Keith field, and a 50% interest in the Rhum field.

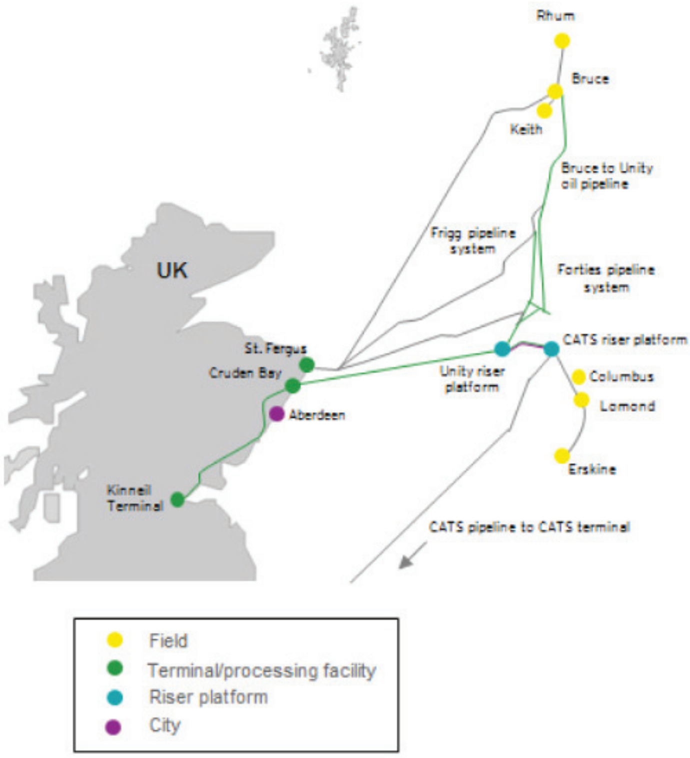
The Bruce field is operated by BP and, upon Completion, will be operated by Serica UK, with partners Total E&P UK Limited (43.25%), BHP Billiton Petroleum Great Britain Limited (16%), Marubeni Oil and Gas (North Sea) Limited (3.75%) and BP (1%). BP currently owns a 37% interest in the field and will retain a 1% interest following Completion. The Bruce field was discovered in June 1974 and is located in the UK Northern North Sea, 350 km northeast of Aberdeen at a water depth of 122 metres and with an area of approximately $75km^2$. Field development was sanctioned in 1990 and production started in 1993. Production is primarily gas with associated condensate and NGLs. The field produces from 11 reservoir units, separated by faulting and in 2017 has had a cumulative production since 1993 of over 3tcf. Production at the Bruce field in the first half of 2017 was approximately 4,400 boepd[6] net to BP[7]. The field utilises three bridge-linked platforms and a subsea manifold for production. There is a production platform housing a crew of up to 168 with production and facilities equipment. The second platform is a drilling platform, with the third platform hosting reception and compression facilities. Gas compression was installed in 2004. The field was originally appraised with 26 wells. To date there are over 60 well penetrations in the field with 21 producing wells.

The Keith field lies 6.8 km to the southwest of the Bruce field in a water depth of 120 meters and has been developed as a subsea tie-back to the Bruce complex. It is operated by BP and on Completion will be operated by Serica UK (34.83%), with partners Total E&P UK Limited (25%), BHP Billiton Petroleum Great Britain Limited (31.83%) and Marubeni Oil and Gas (8.34%). Keith was confirmed as a separate field to Bruce after drilling in 1987 and first came on production in 2000, with a second phase of development in 2002. Production at the Keith field over the first half of 2017 was approximately 450 boepd[8] net to BP. No further capital programmes are planned on Keith as the field is in the final stages of its producing life.

The Rhum Field lies in the Northern North Sea 380 km north east of Aberdeen, 44 km north of the Bruce field and in 109 metres of water and is operated by BP (50%). On Completion, it will be operated by Serica UK (50%), with Iranian Oil Company (U.K.) Limited (50%) as its partner. Shareholders' attention is drawn to paragraph 5.3 of Part II (*Further Information on the BKR Assets*) and the risk factors in relation to the consequences of IOC being a partner in the Rhum field on page 42 of Part IV (*Risk Factors*). In particular, as a consequence of US primary sanctions imposed on Iran, BP, as the current operator, has obtained a licence granted by OFAC for the deployment of certain US-related resources on field operations. The Company will apply for a licence on similar terms prior to Completion. The field was discovered by BP in 1977 and encountered high pressure and high temperature gas. Production started in December 2005 and peaked at 300 mmscfd (approximately 51,000 boepd), shortly after start-up. Cumulative production since 2005 has been approximately 65 million boe gross, and over the first half of 2017 gas and condensate production was approximately 13,500 boepd[9] net to BP from two wells. A third well (Rhum R3 Well) was drilled but not brought into production due to complications with the completion and hydrate formation. The Rhum field partners are planning that the Rhum R3 Well be re-entered and completed for production in 2018.

6 OGA Production Statistics H1 2017.
7 Calculated on the basis of a 36% interest in the Bruce field.
8 OGA Production Statistics H1 2017.
9 OGA Production Statistics H1 2017.

The location of the BKR Assets in the North Sea is shown in Figure 1 below.



Further details of the BKR Assets are set out in Part II (*Further Information on the BKR Assets*).

5. Trading and prospects in relation to BKR Assets

Preliminary estimates of average production in the second half of 2017 based on field data up to 26 November 2017, the latest date for which information is available, production from the BKR Assets, net to BP, averaged approximately 14,600 boepd[10] (first half of 2017: approximately 18,500 boepd[11]). This period included a planned shutdown for platform maintenance on the Bruce field and well intervention work on both the Bruce and Rhum fields to enhance future production. Gas produced from Rhum has a high CO_2 content requiring gas blending. A recommendation has been made by the Uniform Network Code Modifications Panel to increase the permitted levels of CO_2 in the gas delivered into the National Transmission System at St. Fergus terminal with a decision expected from the relevant authority, Ofgem, before the end of 2017. If increased levels of CO_2 are permitted, payments would no longer need to be made for blending gas with a resultant reduction in costs and risk of periods of no-production due to the unavailability of blending gas, which has, from time to time in the past, impacted on sales of Rhum field gas. Serica UK has agreed to sell its share of gas, oil and NGLs to BP at market prices pursuant to the Product Sales Agreements. The proceeds from these sales will constitute a large part of Serica's net income with the benefit of the cash flows accruing to Serica from the effective date of the Acquisition which is 1 January 2018. Under the terms of the Acquisition, Serica UK will pay 60%, 50%, 40% and 40% of the pre-tax net cash flows to BP as deferred cash consideration in respect of each of the years 2018, 2019, 2020 and 2021 respectively. Serica UK has put in place gas price hedging setting a minimum gas price of 35 pence per therm for a proportion of its retained share, after payment to BP, of estimated BKR Assets gas production being 60% for 2018, 60% for 2019 and 40% for the first half of 2020.

The near-term work programme on the BKR Assets includes the application of well stimulation techniques on certain of the Bruce wells to improve production from the Bruce field and, on the Rhum field, a well intervention is planned over the Rhum R3 Well to remove hydrates and wireline equipment which are currently preventing production from the well. The Bruce well stimulation programme and Rhum R3 Well intervention are expected by the Directors to result in increased

10 Calculated on the basis of a 36% interest in the Bruce field.

11 Calculated on the basis of a 36% interest in the Bruce field.

production levels from the BKR Assets starting during 2018. As further explained at paragraph 10 of this Part I (*Letter from the Chairman of Serica*), Serica UK has agreed to make a contingent payment to BP under the Acquisition Agreement in the event of a successful outcome to the Rhum R3 Well intervention. Costs relating to the well intervention are included in the net cash flow sharing arrangements with BP. No further capital programmes are planned on Keith as the field is in the final stages of its producing life. Subject to Completion, Serica intends to continue production from its single well as long as economically viable, but it is currently scheduled to cease production in 2019. Following Completion, Serica intends to develop a programme of further investment to enhance Reserve recovery and extend production profiles on Bruce and Rhum.

6. Background information on Serica

Serica has interests in a mixture of production, development and exploration assets.

All of Serica's current production comes from Erskine, a gas and condensate field located in the Eastern Central Graben, UK Central North Sea and acquired from BP in June 2015. Serica UK's partners are Chevron North Sea Limited 50% (operator) and Chrysaor Limited 32% with Serica UK holding the remaining 18%. Field facilities comprise a normally unmanned platform, remotely controlled from the Lomond platform, with five wells producing primarily from the Pentland Sandstone with further contribution from the Erskine and Heather sands. The Erskine field commenced production in December 1997, and since then has produced approximately 120 mmboe (gross).

Average Erskine daily production in 2016 was 1,631 boepd net to Serica UK, including a six-month shut-in for treatment of a wax blockage in the Lomond to Everest condensate export line and maintenance work. Production in the first half of 2017 averaged approximately 2,800 boepd net to Serica UK.

The Columbus gas condensate field, which is a development project, is located in close proximity to the Lomond platform, which is the offtake route for production from Serica UK's Erskine producing interest. Serica UK is the operator of the Columbus field with partners EOG Resources United Kingdom Limited (25%) and Endeavour Energy UK Limited (25%) and Serica UK holding the remaining 50%. The field is located in the Eastern Central Graben, UK Central North Sea and the reservoir is located within the Forties Sandstone. The Columbus field has been appraised with four wells and is planned to be developed with a single production well. Serica UK is currently working towards a full field development plan for submission to the Oil and Gas Authority by mid-2018 with a view to commencing development work before the end of 2018. First gas is currently targeted for 2020.

Serica also has exploration interests in the Central North Sea (Rowallan Prospect), the Slyne and Rockall Basins offshore Ireland and the Luderitz Basin offshore Namibia. Serica also currently holds a 20% non-operated interest in Block 113/22a in the East Irish Sea, but Serica proposes to relinquish this licence as soon as permission is granted from the UK authorities which is expected in late 2017.

The Rowallan Prospect is located in the Central North Sea, around 20km west of the Columbus field. Serica UK's partners comprise ENI UK Limited (operator – 40%), JX Nippon Exploration and Production (U.K.) Limited (25%) and Mitsui E&P UK Limited (20%), with Serica UK holding the remaining 15%. Preparations for drilling the Rowallan prospect are underway.

Serica has a 100% interest in several blocks in the Slyne Basin offshore Ireland and has secured a two-year extension to licence 1/06 to further explore the potential first identified through the Bandon oil discovery drilled by Serica in 2009. Serica is seeking to identify a farm-in partner to share drilling and development costs and, in the event of a commercial discovery, to follow with a development to bring the field on production. Serica also has extensive acreage in the Rockall Basin offshore Ireland. It is seeking to bring in partners to share the drilling of exploration wells on licences 4/13 and 1/09. In the remainder of 2017, further work is planned on the licences to investigate the potential for productive fractured basement.

In the Luderitz Basin in Namibia, Serica's partners are National Petroleum Corporation of Namibia (Pty) Limited 10% and Indigenous Energy (Pty) Limited 5% with Serica holding the remaining 85%. Serica conducted a 4,180km^2 3D seismic survey in 2012. The 3D seismic data has identified giant carbonate prospects as well as large, more conventional Cretaceous submarine fan prospects supported by seismic anomalies. The drilling of a well will be subject to the introduction of a new partner to meet a significant proportion of the costs.

Further details of Serica's production, development and exploration assets are set out in Part III (*Further Information on Serica*).

7. Serica current trading and prospects

Serica's only current source of production is from Serica UK's 18% interest in the Erskine field located in the Central North Sea Area of the UKCS.

Erskine wells have demonstrated capability to produce over 3,500 boepd net to Serica UK from five producing wells when unconstrained by planned or unplanned shut-ins or offtake restrictions. Production in the first half of 2017 averaged approximately 2,800 boepd net to Serica at an operating cost to Serica UK of approximately US$14/boe with high uptime performance from Erskine/Lomond export facilities and good performance from the Erskine wells. Production during the second half of 2017 is expected to be lower due to an eight week shut-in for maintenance work on Lomond coinciding with a planned maintenance programme of the Forties Pipeline System and then continuing work to clear the condensate export line of wax deposits. Since recommencement of production on 22 September 2017 and up to 22 November 2017 (the latest date for which figures are available) the field has delivered at an average rate of approximately 2,450 boepd net to Serica UK. The operator of the Lomond platform has commenced pigging operations to clear the line of ongoing wax deposition which, if successful, will enable the Erskine field to increase production levels to the field's full potential.

The Company intends to submit a Field Development Plan for the Columbus field to the OGA by mid-2018. The Columbus field lies close to the Lomond field and is estimated in the Serica CPR (Technical Discussion, page 5) to hold approximately 6.7 mmboe of 2C contingent resources net to Serica UK comprising both gas and condensates. Serica UK has a 50% working interest and is operator for the field. The field is proposed to be developed with a single well. The Company is currently evaluating two alternative export routes, either via the Lomond platform with an extended reach well drilled from the platform or via Shearwater with a subsea completed well connected to a pipeline planned by the Arran group. Production could commence either in 2020 in the case of the Lomond route or 2021 in the case of the Shearwater route. The Lomond and Shearwater export routes are subject to the successful outcome of commercial negotiations with the operator of Lomond or with the operators of Shearwater and Arran, respectively and to approval by the OGA.

Also in 2018, ENI UK Limited, the operator of UK Block 22/19c, plans to drill an exploration well to test the Rowallan Prospect 20km west of the Columbus field, a high pressure, high temperature prospect lying at Middle Jurassic and Triassic levels. The Serica CPR estimates the Best Estimate prospective resources in the prospect net to Serica's 15% working interest to be approximately 19.7 mmboe (based on the Serica CPR, Technical Discussion, page 8, shown on an equivalent unit basis where natural gas is converted to oil equivalent). Serica UK's share of the drilling costs for the well are fully carried by JX Nippon Exploration and Production (U.K.) Limited. In the event of success, the Directors believe there may be further upside in the block with other geologically similar prospects/leads.

In the Slyne Basin and in the Rockall Basin offshore Ireland, and in the Luderitz Basin offshore Namibia, Serica will continue to seek partners to share drilling, exploration and development costs.

The Company has also made applications in the UKCS 30th Licensing Round.

As at 17 November 2017, the Company held cash balances and term deposits of in aggregate approximately US$34 million and had no borrowings and no material unfinanced exploration or drilling commitments.

8. Key strengths of the Enlarged Group

Following Completion the Enlarged Group will have the scale, profile, diversity, cash flow, operating capability and financial resources to place it amongst the largest, by UK production, of the quoted European independent oil and gas companies operating on the UKCS. With no borrowings (save for up to £16 million under the Prepayment Facility), net cash resources, carried forward tax losses and a full operating capability the Directors believe the Enlarged Group will be well placed to compete in the upstream oil and gas industry and deliver further value-accretive growth to its Shareholders.

9. Enlarged Group strategy

The Directors intend that the Enlarged Group will build upon its technical, commercial and financial strengths both organically, through its existing assets, and inorganically, through further acquisitions which have near term potential. As operator of the BKR Assets and Columbus development, Serica will seek to enhance the value of its assets to the benefit of stakeholders and partners through increased operating efficiencies to reduce costs and the application of new technologies to increase production, maximise recovery and extend producing life of the fields where possible without compromising the highest safety, environmental and employment standards. As a non-operator, Serica will seek to work closely with its operators to maximise the recovery of Reserves and resources. The Directors intend to build new opportunities by combining the operational skills of BP staff with the existing Serica management team. The Company will also continue to seek ways of broadening its asset base and resources through selected acquisitions where these can be identified to strengthen its portfolio and add to its capabilities over the full exploration to production cycle.

10. Principal terms of the Acquisition

Pursuant to the Acquisition Agreement, Serica UK has conditionally agreed to acquire the entire interests and operatorship of BP in the Bruce, Keith and Rhum fields save for a 1% interest in the Bruce field which is proposed to be retained by BP. In addition, pursuant to the Product Sales Agreements, Serica UK will also sell to BP, Serica UK's share of gas, oil and NGLs produced from the BKR Assets. The purchase of the BKR Assets represents a significant step in the evolution of the Company from an exploration and development group with no operating role in producing fields to the operator of major gas fields in the North Sea.

The consideration for the Acquisition is to be entirely funded by cash, with the bulk of the consideration being deferred and/or contingent and being financed from the net cash flows from the BKR Assets. The consideration is made up of the following elements:

- An initial cash consideration payable at the date of Completion of £12.8 million. The Acquisition is structured, however, such that Serica UK is entitled to a share of the net cash flows from the BKR Assets during the interim period from the effective date of the Acquisition (1 January 2018) to the date of Completion, which, in light of the conditions to be satisfied as referred to below, is not expected to be until mid-2018. The Directors anticipate that Serica UK's share of the net cash flow in this period will be more than the amount of the Initial Consideration and, since these net cash flows are to be netted off against the amount of the Initial Consideration, this would mean that at Completion there would be a net amount paid to Serica UK by BP. Serica UK also has the option to augment this net cash flow by drawing down the amount of the Initial Consideration pursuant to the Prepayment Facility described below.
- Up to £16 million is payable to BP in January 2019 or thereafter provided that the Rhum R3 Well has achieved a specified minimum production threshold for 90 days during the first year following completion of the workover of the well anticipated to take place during 2018. If the production threshold is not met, this element of the consideration will not be paid. In addition, even if the well production does meet the production targets, 50% of this consideration will be deferred if gas production from the Rhum field still requires blending fees by 1 January 2019 or an alternative solution with the same economic benefit has not been found. If on 1 January 2020, the requirement for blending fees remains or an alternative solution with the same economic benefit has not been found, such remaining 50% of the consideration will not be payable.
- Up to a further £23.1 million in aggregate is payable in three annual instalments (of up to approximately £7.7 million each) in respect of 2019, 2020 and 2021 if the Rhum field production volumes and sales prices meet or exceed certain agreed levels. The amounts payable will be reduced if Rhum field production and the price achieved for sales of Rhum gas do not meet the agreed levels.
- BP will also receive a share of pre-tax net cash flow from the BKR Assets of 60% in 2018, 50% in 2019 and 40% in each of 2020 and 2021. The net cash flow shares are calculated on a monthly basis. No amounts are payable by Serica UK unless this cash flow is positive and amounts are repayable to Serica UK in the event of negative cash flow, up to the amount of Serica UK has already paid in the same year. Net negative cash flow during the year can be carried forward to be offset against positive cash flow in subsequent years. The arrangements in relation to Serica UK and BP sharing net cash flows from the BKR Assets are set out in the Net Cash Flow Sharing Deed summarised at paragraph 11.1(e) of Part XII (*Additional Information*).

- Serica UK will pay additional consideration equal to 30% of BP's retained share of decommissioning costs when due, reduced by the tax relief that BP receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the Acquisition.
- Serica UK will also pay deferred consideration equal to 90% of its share of the realised value of oil in the Bruce pipeline at the end of field life.

Pursuant to the Product Sales Agreements, Serica UK will sell its share of natural gas, oil and NGLs from the BKR Assets to BP entities. The Product Sales Agreements provide for sales prices based on standard spot pricing, subject to deductions for marketing fees and normal system charges. In addition, pursuant to the Prepayment Facility, BP Gas will provide up to £16 million to cover agreed hedging costs and the Initial Consideration, if required, with repayments out of 35% of Serica UK's retained share of gas sales in respect of the BKR Assets to be made on a monthly basis subject to a six-month payment holiday from the date of Completion. The Prepayment Facility and associated hedging provides Serica UK with additional liquidity and mitigates gas price risk.

Serica and Serica UK have each provided certain financial guarantees to BP pursuant to the Security Agreements in relation to the obligations under the Acquisition documents, the Net Cash Flow Sharing Deed and gas sales arrangements. These include a charge over the BKR Assets during the period of the Net Cash Flow Sharing Deed and a guarantee from Serica in respect of certain of Serica UK's obligations under the Sale and Purchase Agreement and gas sales arrangements. There are also constraints on Serica UK selling or encumbering the BKR Assets in the future.

BP will retain liability for all the costs of decommissioning facilities and wells existing at Completion relating to the BKR Assets. Serica UK will pay for the costs of decommissioning new facilities.

Completion of the Acquisition is conditional *inter alia* on:

- the OGA's consent to the assignment of the BKR Assets to Serica UK and the transfer of operatorship of the BKR Assets to Serica UK;
- a waiver or expiry of pre-emption rights of Iranian Oil Company (UK) Limited, BP's partner on the Rhum field;
- the approval of BP's partners in the BKR Assets to the assignment of the BKR Assets and the transfer of operatorship to Serica UK (the requirement for such approval is customary for transactions of this type);
- clearance being sought by Serica UK and received from HMRC that the tax treatment of the sharing of the net cash flows from the BKR Assets pursuant to the Net Cash Flow Sharing Deed will be applied as intended;
- receipt by Serica UK of an OFAC licence and arrangement of satisfactory banking facilities to conduct Rhum operations;
- receipt by BP of renewals of licences P.209 and P.198 in relation to the BKR Assets;
- the amendment of certain decommissioning security agreements and operating agreements in relation to the BKR Assets to give effect to the retention by BP of its liability for decommissioning and voting rights on decommissioning matters pursuant to the Acquisition; and
- the passing of the Resolution at the General Meeting.

In addition, Completion will not take place unless Admission also takes place.

It is anticipated that some of the conditions (and in particular the OGA consents referred to above) will take some months to satisfy. Accordingly, it is not anticipated that Completion will take place until mid-2018.

In addition to the conditions under the Acquisition Agreement, Serica UK has the right to terminate the Acquisition Agreement prior to Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field, the Keith field and/or the Rhum field. Each of Serica UK or BP can also terminate the Acquisition Agreement if there is a cessation of production from the Rhum field due to sanctions. IOC is a joint venture partner in the Rhum field and is subject to US restrictions in relation to Iran. As an English company, Serica is not a US person and is not restricted in its partnership joint venture arrangements but will comply with US sanctions law in every respect insofar as it applies to US persons as they relate to the Rhum field operations.

The Acquisition Agreement also contains customary warranties in relation to the BKR Assets from BP for a transaction of this nature.

BP and Serica UK have also entered into the Transfer of Operatorship Agreement pursuant to which the parties have set out the process and obligations between them for transferring to Serica UK the operatorship of the BKR Assets. The transfer of operatorship to Serica UK is a substantial undertaking and requires the consent of OGA and BP's field partners in the BKR Assets. The transfer of operatorship involves amongst other things Serica UK taking on approximately a further 110 employees from BP, the transfer of inventory, the assignment or replacement of a substantial number of contracts relating to the day to day operations of the BKR Assets and the identification of IT software and hardware to be transferred or replaced. The Company also expects to open its own office in Aberdeen from which it will manage day to day operations. The Transfer of Operatorship Agreement includes mutual indemnities in relation to the matters to be performed under it.

Further details of the Acquisition Agreement, the Product Sales Agreements, the Prepayment Facility, the Net Cash Flow Sharing Deed, the Transfer of Operatorship Agreement and the Security Agreements are set out in paragraph 11.1 of Part XII (*Additional Information*). Serica is committed to protect terms and conditions of employment of BP staff being transferred to Serica above and beyond TUPE requirements for a period of at least 12 months after the date of Completion. Serica has no plans to reduce workforce numbers and will consult and engage with in-scope employees, contractors and agency staff throughout the sale process during which time a transition plan will be put in place.

11. Summary financial information on Serica and the BKR Assets

Set out below is a summary of the audited consolidated results of Serica and the unaudited financial information in respect of the BKR Assets for the years ended 31 December 2014, 31 December 2015 and 31 December 2016 and the unaudited financial information of Serica and in respect of the BKR Assets for the six month period ended 30 June 2017.

The summary audited consolidated financial information of Serica for (i) the year ended 31 December 2014 has been extracted without material adjustment from the consolidated financial statements included in the Serica Group's 2014 annual report and accounts; (ii) the year ended 31 December 2015 has been extracted without material adjustment from the consolidated financial statements included in the Serica Group's 2015 annual report and accounts; (iii) the year ended 31 December 2016 has been extracted without material adjustment from the consolidated financial statements included in the Serica Group's 2016 annual report and accounts; and (iv) the six month period ended 30 June 2017 has been extracted without material adjustment from the unaudited financial statements included in the Serica Group's 2017 interim financial statements, each of which has been incorporated by reference in Part VIII (*Historical Financial Information on Serica*).

The summary unaudited financial information in respect of the BKR Assets has been based on a review of BP's BKR Asset accounts and prepared by the Company. Additional financial information on the BKR Assets can be found in Part VII (*Unaudited Historical Financial Information on the BKR Assets*).

Investors should read the whole of the Company's published audited historical financial information and unaudited financial statements and should not rely solely on the summarised information set out below.

Serica

	Six months ended 30 June 2017 (Unaudited)	**Year ended 31 December 2016 (Audited)**	**Year ended 31 December 2015 (Audited)**	**Year ended 31 December 2014 (Audited)**
	US$'000	*US$'000*	*US$'000*	*US$'000*
Revenue	21,922	21,432	24,017	—
Operating Profit/(Loss) before Net Finance Revenue and Tax	11,168	3,449	4,484	(35,649)
Profit for the period	10,343	10,838	6,489	(36,076)
Cash and cash equivalents	25,083	16,593	21,602	9,893
Net assets	95,462	85,095	74,167	66,337

BKR Assets

	Six months ended 30 June 2017 (Unaudited)	**Year ended 31 December 2016 (Unaudited)**	**Year ended 31 December 2015 (Unaudited)**	**Year ended 31 December 2014 (Unaudited)**
	US$'000	*US$'000*	*US$'000*	*US$'000*
Revenue	130,059	159,036	207,891	118,098
Operating expenditure	(55,864)	(109,226)	(161,817)	(117,078)
EBITDA	74,195	49,810	46,075	1,021
Impairment, depreciation, decommissioning accretion	(1,691)	37,448	90,024	(451,534)
Profit Before Tax	72,504	87,257	136,099	(450,514)

12. Directors, senior managers and employees

As at the date of this document, the Directors of the Company are as follows:

Antony Craven Walker	*Executive Chairman*
Mitchell Robert Flegg	*Chief Executive Officer*
Robert Eben Neil Pike	*Non-Executive Director and Senior Independent Director*
Ian Roland Vann	*Non-Executive Director*

It is intended that prior to Completion a further two non-executive directors will be appointed to the Board. Details of the current directors are set out below.

Antony Craven Walker *Executive Chairman (aged 74)*

Tony Craven Walker joined the Serica Group as non-executive Chairman in August 2004. Following the retirement of the then Chief Executive Officer in April 2011 he acted as Interim Chief Executive, and with effect from 1 June 2015 he took on the role of Executive Chairman following the departure of the two Executive Directors. He started his career with BP and has been a leading figure in the British independent oil industry since the early 1970s. He founded two British independent oil companies, Charterhouse Petroleum, where he held the post of Chief Executive, and Monument Oil and Gas, where he held the post of Chief Executive and later became Chairman. He was also a founder member of BRINDEX (Association of British Independent Oil Exploration Companies).

Mitchell Flegg *Chief Executive Officer (aged 57)*

Mitch Flegg rejoined the Board on 21 November 2017. He has over 35 years of experience in the upstream oil and gas industry, including positions at Shell and Enterprise Oil. Mitch first joined Serica in 2006 and had been responsible for all drilling and development operations. He was promoted to the position of Chief Operating Officer in March 2011 and appointed to the Board of

Serica in September 2012. He left Serica in May 2015 to become chief executive officer of Circle Oil plc. Mitch re-joined the Board of Serica on 21 November 2017 as Chief Executive Officer.

Neil Pike *Non-Executive Director and Senior Independent Director (aged 72)*

Neil Pike joined the Serica Group as a director in 2004. He has been involved in the global petroleum business as a financier since joining the energy department at Citibank in 1975. Neil remained an industry specialist with Citibank throughout his career until he joined Serica and was closely involved in the development of specialised oil field finance. Latterly he was responsible for Citibank's relationships with the oil and gas industry worldwide.

Ian Vann *Non-Executive Director (aged 68)*

Ian Vann joined the Board in 2007. He was employed by BP from 1976, and directed and led BP's global exploration efforts from 1996 until his retirement in January 2007. He was appointed to the executive leadership team of the Exploration & Production Division of BP in 2001, initially as Group Vice President, Technology and later as Group Vice President, Exploration and Business Development.

The Group also employs the following Senior Managers.

Clara Altobell *Vice President (Technical)*

Clara Altobell joined Serica in 2008 and has been responsible for managing operations for its exploration, development and producing assets. She has over 20 years of oil and gas operations experience and holds a Masters of Petroleum Engineering from Imperial College, London. Prior to Serica, she worked at Burlington Resources for twelve years, providing engineering support for production, testing and completions in its operated Algerian assets as well as specialising in production technology, reserves and budgeting. She was chair of the SPE London Section and Continuing Education chair for a number of years. She also held a non-executive position on the board of SPE Europe.

Andrew Bell *Vice President (Finance)*

Andy Bell has worked closely with Serica as a consultant since 2004, assisting Serica's introduction to AIM in 2005 and providing general financial and commercial advice thereafter. He became a Serica employee on 21 November 2017. He has some 35 years of experience in upstream oil and gas, particularly with early stage and growing companies a number of which developed into successful international businesses including, in the UK, Charterhouse Petroleum Plc (1982 to 1986) where he set up the joint venture accounting function and Monument Oil and Gas Plc where he was Financial Controller from 1989 until its sale to Lasmo Plc in 1999 and, in Canada, Centric Energy Corp. where he was CFO from 2007 until its sale to Africa Oil Corp in 2011.

Danny Fewkes *Group Treasurer*

Danny Fewkes has over 20 years' experience in various financial roles, primarily focusing on the oil and gas sector. He joined Serica in January 2006 following the Company's listing on AIM and was appointed as Group Treasurer in June 2015. Danny has had significant involvement in the Company's corporate and asset transactions, including equity offerings, debt facility financing, South East Asia interest disposals and the acquisition of an 18% Erskine interest from BP. He qualified as a chartered accountant at Price Waterhouse and is a member of the Institute of Chartered Accountants in England and Wales.

Stephen Lambert *Vice President (Commercial)*

Stephen Lambert has over 20 years' experience in the oil and gas sector, engaged primarily on commercial and business development projects in the UK and overseas. He worked with Serica on the transaction with BP and joined the Company as an employee on 21 November 2017. Stephen has a wide experience in commercial and business development in the independent and large cap sectors, including roles with Monument Oil and Gas Plc and Chevron Corporation, where he was General Manager for Strategy and Planning in Business Development. Prior to joining Serica, Stephen had eight years of experience with JX Nippon UK, most recently as Deputy General Manager. He is a member of the Institute of Chartered Accountants of England & Wales and the Chartered Institute of Taxation. He is also a member of the board of Mediation Hertfordshire.

Prior to Completion, the Company plans to appoint further Senior Managers to fill the following roles:

- Vice President (Subsurface);

- Manager (HSE); and
- Vice President (Operations).

The Company currently employs eight employees. Approximately 110 employees are currently employed by BP in relation to the BKR Assets, and, subject to Completion, it is anticipated that these employees will be transferred across to Serica with the BKR Assets. Serica is committed to protect terms and conditions of employment of BP staff being transferred to Serica above and beyond TUPE requirements for a period of at least 12 months after the date of Completion. Serica has no plans to reduce workforce numbers and will consult and engage with in-scope employees, contractors and agency staff throughout the sale process during which time a transition plan will be put in place. In addition, assuming all employees transfer across to Serica, Serica expects to engage approximately a further 20 employees in conjunction with the activities of the BKR Assets. Further details of the Group's employees, and the employees engaged in relation to the BKR Assets are set out in paragraph 17 of Part XII (*Additional Information*).

13. Competent persons' reports

Shareholders' attention is drawn to the full text of the BKR CPR and the Serica CPR which are set out in full in Parts V (*Competent Person's Report on the BKR Assets*) and VI (*Competent Person's Report on Serica*) respectively.

14. Employee Incentive Schemes

The Company has adopted the following incentive plans for its executive management and employees:

- a long term executive incentive plan (*the Serica Energy plc Long Term Incentive Plan*), which permits the grant of share based awards, which was adopted on 20 November 2017;
- a discretionary share option plan which was adopted by the Board on 20 November 2017 (*the Serica Energy plc 2017 Company Share Option Plan*);
- a tax advantaged all-employee share based incentive plan which was adopted on 29 January 2009 (*the Serica Energy plc Share Incentive Plan*); and
- further, the Company operates a historical share option plan, which was adopted on 14 November 2005, called the Serica Energy plc Share Option Plan (the **"2005 Plan"**). There remain outstanding options under the 2005 Plan.

The Company also operated an historical discretionary share option plan, the Serica Energy plc Company Share Option Plan, which was adopted by Shareholders on 23 June 2016. However, it was determined by the Board that it should terminate the 2016 CSOP on 29 November 2017 and, instead adopt the replacement 2017 CSOP, so as to ensure that this plan conformed to the same dilution limits and amendment provisions as the new Serica Energy plc Long Term Incentive Plan. There are no outstanding options under the 2016 CSOP. The 2016 CSOP has now been terminated.

In due course, and subject to Completion, the Company also proposes to adopt a new all-employee savings-related share option plan, which will be known as the Serica Energy 2018 Sharesave Plan. The terms of this plan are subject to the Board's approval.

As at the date of this document and taking into account options and awards to be granted shortly following its issue, the following share options / awards have been or will shortly following the publication of this document be granted under the Serica Energy plc Long Term Incentive Plan, the Serica Energy plc Share Incentive Plan and the 2005 Plan.

The Board has not made any grants under the 2017 CSOP.

Serica Energy plc Long Term Incentive Plan

Director/ Employees	**Total number of shares to be granted subject to Deferred Bonus Share Awards**
Antony Craven Walker	225,000
Mitchell Flegg	225,000
Employees below Board level	350,000 (in aggregate)
TOTAL	**800,000**

Director/ Employees	Total number of shares to be granted subject to Performance Share Awards
Antony Craven Walker	1,500,000
Mitchell Flegg	1,500,000
Employees below Board level	2,250,000 (in aggregate)
TOTAL	**5,250,000**

Serica Energy plc Share Option Plan 2005 (the 2005 Plan)

Director/ Employees	Total number of shares currently under option
Antony Craven Walker	2,500,000
Employees below Board level	5,696,330 (in aggregate)
TOTAL	**8,196,330**

Serica Share Incentive Plan

There are a total of 1,463,663 Ordinary Shares outstanding under the Serica Share Incentive Plan. These comprise of 253,837 Partnership Shares, 507,674 Matching Shares and 702,152 Free Shares (as defined under paragraph 8.6 of Part XII (*Additional Information*)). The dates of grant range from 29 April 2009 to 3 November 2017 and the vesting dates range from 29 April 2012 to 3 November 2022.

In aggregate the options/awards under all of the Company's incentive plans represent 5.96% of the Company's issued ordinary share capital as at the Latest Practicable Date, including the Deferred Bonus Share Awards and Performance Share Awards which will be granted on or as soon as reasonably practicable following the publication of this document.

Further details of the Serica Long Term Incentive Plan, the 2005 Plan, the 2017 CSOP, the Serica Energy plc Share Incentive Plan and details of the proposed new Sharesave Plan which is proposed to be adopted, are set out in paragraph 8 of Part XII (*Additional Information*).

15. Corporate governance and share dealing code

The Board of Directors fully endorses the importance of sound corporate governance. The Ordinary Shares were until 2015 traded on both AIM and on the TSX, but following application by the Company they were delisted from the TSX in March 2015. The Directors believed that the minimal trading activity of the Ordinary Shares on TSX no longer justified the expense and administrative effort of maintaining a dual listing. Following this date, the Ordinary Shares continued to trade solely on AIM.

As a company traded on AIM, the Corporate Governance Code does not apply to the Company. However, the Board applies the principles of the Corporate Governance Code to the extent that it considers it reasonable and practical to do so given the size and nature of the Company.

Although the Company has now delisted from the TSX, the Company is still considered to be a reporting issuer in a number of Canadian provinces. The corporate governance guidelines applying to reporting issuers in Canada are set out under Ontario Securities Commission National Policy 58-201 (the "**Corporate Governance Guidelines**") so the Company is also required to comply with those guidelines. The Company is a 'designated foreign issuer' as defined under National Instrument 71-1-2- Continuous Disclosure and Other Exemptions Relating to Foreign Issuers.

The Board and its Committees

As at the date of this document, the Board comprises the Executive Chairman, the Chief Executive Officer who was appointed to the Board on 21 November 2017 and two Non-Executive Directors, one of whom holds the position of Senior Independent Director. The Company considers all of the Non-Executive Directors to be independent in character and judgement and to have the range of experience and calibre to bring independent judgement on issues of strategy, performance, resources and standards of conduct.

Prior to Completion, is anticipated that two further independent Non-Executive Directors will be appointed to the Board.

The Board retains full and effective control over the Company. The Company holds regular Board meetings at which financial, operational and other reports are considered and, where appropriate, voted on. The Board is responsible for the Company's strategy, performance, key financial and compliance issues, approval of any major capital expenditure and the framework of internal controls. The matters reserved for the Board include, amongst others, approval of the Company's long term objectives, policies and budgets, changes relating to the Company's management structure, approval of the Company's annual report and accounts and ensuring maintenance of sound systems of internal control.

There is a clearly defined organisational structure with lines of responsibility and delegation of authority to executive management. The Board is responsible for monitoring the activities of the executive management. The Chairman has the responsibility of ensuring that the Board discharges its responsibilities. In the event of an equality of votes at a meeting of the Board, the Chairman has a second or casting vote. The Board believes that there is an adequate balance between the non-Executive and Executive Directors, both in number and in experience and expertise, to ensure that the Board operates independently of executive management and prior to Completion it is anticipated that two further independent Non-Executive Directors will be appointed to the Board. There is currently no formal Board performance appraisal system in place but the Corporate Governance and Nomination Committee considers this as part of its remit.

The Chairman was independent on appointment but has not been independent for the whole of his tenure due to holding share options and his executive responsibilities.

Individual Directors may engage outside advisors at the expense of the Company upon approval by the Board in appropriate circumstances.

The Board has established a Corporate Governance and Nomination Committee, an Audit Committee, a Reserves Committee, a Remuneration and Compensation Committee and a Health, Safety and Environmental Committee. The terms of reference of the Corporate Governance and Nomination, Audit and Remuneration and Compensation Committees can be found on the Company's website www.serica-energy.com.

Corporate Governance and Nomination Committee

The Corporate Governance and Nomination Committee is responsible for the Company's observance of the Corporate Governance Code and the Corporate Governance Guidelines where they apply to the Company, for compliance with the AIM Rules, the rules applicable to designated foreign issuers in Canada and for other corporate governance matters, including compliance with the Company's Share Dealing Code and with AIM and MAR in respect of dealings by Directors, employees and connected persons in the Ordinary Shares. The Corporate Governance and Nomination Committee is responsible for monitoring the effectiveness of the Board and its Committees, proposing to the Board new nominees for election as Directors to the Board, determining successor plans and for assessing Directors on an ongoing basis.

The Corporate Governance and Nomination Committee is chaired by Neil Pike and its other members are Antony Craven Walker and Ian Vann.

Audit Committee

The Audit Committee's purpose is to assist the Board's oversight of the integrity of the financial statements and other financial reporting, the independence and performance of the auditors, the regulation and risk profile of the Group and the review and approval of any related party transactions. The Audit Committee may hold private sessions with management and the external auditor without management present.

The Audit Committee is chaired by Neil Pike and its other member is Ian Vann.

Reserves Committee

The Reserves Committee is a sub-committee of the Audit Committee. The Reserves Committee's purpose is to review the reports of the independent reserves auditors pursuant to Canadian regulations which require that the Board discuss the reserves reports with the independent reserves auditors or delegate authority to a reserves committee comprised of at least two Non-Executive Directors. The committee is chaired by Ian Vann and its other member is Neil Pike.

Remuneration and Compensation Committee

The Remuneration and Compensation Committee meets to consider all material elements of remuneration policy, the remuneration and incentivisation of Executive Directors and senior management and to make recommendations to the Board on the framework for executive remuneration and its cost. The role of the Remuneration and Compensation Committee is to keep under review the Company's remuneration policies to ensure that Serica attracts, retains and motivates the most qualified talent who will contribute to the long-term success of the Company.

The Remuneration and Compensation Committee is chaired by Ian Vann and its other member is Neil Pike.

Health, Safety and Environmental Committee

The Health, Safety and Environmental Committee is responsible for matters affecting occupational health, safety and the environment, including the formulation of a health, safety and environmental policy.

The Health, Safety and Environmental Committee is chaired by Ian Vann and its other member is Antony Craven Walker.

Share dealing code

The company has adopted a code on dealings in securities which the Board regards as appropriate for an AIM company, including compliance with MAR and Rule 21 of the AIM Rules for Companies relating to Directors' and employees, dealings in the Ordinary Shares.

16. Dividend policy

It is the intention of the Board to achieve capital growth for Shareholders. In the short term, the Board therefore intends that any future profits in the Company be retained for reinvestment in the business and, accordingly, the Board is unlikely to declare dividends in the foreseeable future. However, the Board will consider the payment of dividends, subject to the availability of distributable reserves, when it considers it is appropriate to do so.

17. Working capital

In the opinion of the Directors, having made due and careful enquiry, the working capital available to the Enlarged Group will be sufficient for its present requirements that is for at least the next 12 months from the date of Admission.

18. Taxation

Information regarding taxation is set out in paragraph 10 Part XII (*Additional Information*). These details are, however, intended only as a general guide to the current tax position under UK taxation law.

Shareholders who are in any doubt as to their tax positions or who are subject to tax in jurisdictions other than the UK are strongly advised to consult their own independent financial adviser immediately.

19. CREST

The Ordinary Shares are eligible for CREST settlement. Accordingly, settlement of transactions in the Ordinary Shares may take place within the CREST system if the relevant Shareholder so wishes. CREST is a voluntary system and Shareholders who wish to receive and retain share certificates will be able to do so.

20. Risk factors

Shareholders attention is drawn to the Risk Factors set out in Part IV (*Risk Factors*) and to the section entitled ''*Forward Looking Statements*'' on page 1 of this document. Shareholders and prospective investors should, in addition to all other information set out in this document, carefully consider the risks described in Part IV (*Risk Factors*) before making a decision of whether to invest in the Company.

21. Admission and dealings

The Ordinary Shares are expected to continue to trade on AIM up to the time of Completion. Application will also be made to the London Stock Exchange for the Ordinary Shares to be re-admitted to trading on AIM immediately following Completion. It is expected that Admission will become effective and that dealings in the Ordinary Shares, following Completion, will commence at a date to be determined in mid-2018.

22. Shareholder notification and disclosure requirements

Shareholders are obliged to comply with the shareholding notification and disclosure requirements set out in Chapter 5 of the DTR. The DTR can be accessed and downloaded from the FCA's website at http://handbook.fca.org.uk/handbook/DTR. Shareholders are urged to consider their notification and disclosure obligations carefully as failure to make a required disclosure to the Company may result in disenfranchisement.

23. General meeting

The General Meeting notice of which is set out at the end of this document, has been convened for 11.00 a.m. on 18 December 2017 at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA for the purpose of considering and, if thought fit, passing an ordinary resolution to approve the Acquisition for the purposes of Rule 14 of the AIM Rules, which needs to be passed to permit the Proposals to proceed.

To be passed, the Resolution requires a majority of not less than 50% of Shareholders voting in person or by proxy to vote in favour. BP, which owns 5.12% of the Company's issued share capital, will not be prevented from voting on the Resolution. US Shareholders are recommended to seek their own advice as to whether they are entitled to vote on the Resolution, in view of US primary sanctions imposed in relation to Iran and IOC being a partner in the Rhum field. Shareholders' attention is drawn to paragraph 5.3 of Part II (*Further Information on the BKR Assets*) and the risk factors in relation to the consequences of IOC being a partner in the Rhum field on page 42 of Part IV (*Risk Factors*).

24. Action to taken

Shareholders will find enclosed with this document a Form of Proxy for use at the General Meeting. Whether or not you intend to be present at the General Meeting, you are requested to complete and return the accompanying Form of Proxy in accordance with the instructions printed thereon, or, if you hold Ordinary Shares in CREST, to complete and transmit a CREST Proxy Instruction. Guidance notes to assist you to complete the Form of Proxy or to complete and transmit a CREST Proxy Instruction are set out in the notice convening the General Meeting at the end of this document.

It is important that Shareholders complete and sign the enclosed Form of Proxy in accordance with the instructions printed thereon and return it to the Company's registrars, Link Asset Services, PXS 1, The Registry, 34 Beckenham Road, Kent BR3 4ZF, as soon as possible and in any event so as to arrive no later than 11.00 a.m. on 16 December 2017. Alternatively, if you hold Ordinary Shares in CREST, you may instead appoint a proxy by completing and transmitting a CREST Proxy Instruction to the Company's registrars, Link Asset Services. Completion and return of the Form of Proxy or the transmittal of a CREST Proxy Instruction will not preclude Shareholders from attending and voting at the General Meeting, should they wish to do so.

25. Additional information

The attention of investors is drawn to the information contained in Parts II (*Further Information on the BKR Assets*), III (*Further information on Serica*), XI (*Summary of Key Licences and Agreements*) and XII (*Additional Information*), which provide additional information on the Enlarged Group, and in particular Part IV (*Risk Factors*) which sets out certain risk factors relating to the Enlarged Group.

26. Recommendation

The Board considers the Proposals to be in the best interests of Shareholders as a whole. Accordingly, the Board unanimously recommends Shareholders to vote in favour of the Resolution, as the Directors intend to do so in respect of their own beneficial holdings of 8,315,074 Ordinary Shares, representing approximately 3.15% of the Company's existing issued ordinary share capital.

Yours faithfully

Antony Craven Walker
Executive Chairman

PART II – FURTHER INFORMATION ON THE BKR ASSETS

1. Introduction

The BKR Assets comprise all of BP's interests (save for a 1% interest in the Bruce field which BP is retaining), in three fields in the Northern North Sea, all of which are operated by BP.

The Bruce field, in which BP has a 37% interest, is a producing field of primarily gas with associated condensate. Production at the Bruce field in the first half of 2017 was approximately 4,400 boepd[12] net to BP[13] from 21 producing wells. The field has had cumulative production since 1993 of over 3tcf.

The Keith field, in which BP has a 34.83% interest, produced approximately 450 boepd[14] net to BP from a single well in the first half of 2017. The field is in the final stages of its producing life.

The Rhum field in which BP has a 50% interest is a producing field of gas and condensate. Production at the Rhum field in the first half of 2017 was approximately 13,500 boepd[15] net to BP. The field currently produces from two wells although a third well was drilled (the Rhum R3 Well) but not brought into production due to complications with the completion and hydrate formulation. The Rhum field partners are planning that the Rhum R3 Well be re-entered in 2018 and completed for production.

Serica is also acquiring BP's interests in certain blocks in non-producing adjacent areas to the BKR Assets.

2. Summary of Licences

2.1 Bruce field

Asset	Operator	BP Interest(1) (%)	Status	Licence Expiry	Comments
Licence P.209, Block 9/8a Bruce Unit Area (BRUCE)	BP	30.333	Production	15 March 2018	Renewal of the Licence is a condition precedent to Completion
Licence P.276, Block 9/9b Bruce Field (BRUCE)	BP	70.6	Production	N/A – continues to cessation of production	

Note:

(1) BP is retaining a 1% interest in each of the licences P.209 and P.276.

2.2 Keith field

Asset	Operator	BP Interest (%)	Status	Licence Expiry	Comments
Licence P.209, Block 9/8a Keith Field (KEITH)	BP	34.833	Production	15 March 2018	Renewal of the Licence is a condition precedent to Completion

12 OGA Production Statistics H1 2017.

13 Calculated on the basis of a 36% interest in the Bruce field.

14 OGA Production Statistics H1 2017.

15 OGA Production Statistics H1 2017.

2.3 **Rhum field**

Asset	Operator	BP Interest (%)	Status	Licence Expiry	Comments
Licence P.198, Block 3/29a (ALL)	BP	50	Production	15 March 2018	Renewal of the Licence is a condition precedent to Completion

2.4 **Additional blocks outside the Bruce, Keith and Rhum fields**

Asset	Operator	BP Interest (%)	Status	Licence Expiry	Comments
Bruce – non-unitised assets(1)					
Licence P.090, Block 9/9a Rest of Block Excluding Bruce (REST)	Total E&P UK Limited	37	Development	N/A	
Licence P.209, Block 9/8a Rest of Block Excluding Bruce & Keith (REST)	BP	37	Development	15 March 2018	Renewal of the Licence is a condition precedent to Completion
Licence P.276, Block 9/9b Rest of Block Excluding Bruce Unit (REST)	BP	37	Development	N/A	
Licence P.276, Block 9/9c (ALL)	BP	37	Production	N/A – continues to cessation of production	
Rhum – non-unitised assets					
Licence P.566, Block 3/29b (ALL)	BP	100	Production	3 June 2023	
Licence P.975, Block 3/24b (ALL)	BP	100	Production	22 December 2034	
Licence P.975, Block 3/29d (ALL)	BP	100	Production	22 December 2034	

Note:
(1) BP is retaining a 1% interest in each of the licences P.090, P.209 and P.276.

3. Summary of Reserves and Resources

The following tables summarise the Reserves and resources of the BKR Assets. This information has been extracted from the BKR CPR, which can be found in its entirety in Part V (*Competent Person's Report on the BKR Assets*).

Summary of estimated gross and net Reserves and income data attributable to the BKR Assets (as at 1 June 2017)

	Gross			Net Attributable		
	Proved	**Proved & Probable**	**Proved, Probable & Possible**	**Proved**	**Proved & Probable**	**Proved, Probable & Possible**
Oil & Liquids reserves						
From production to planned for development (mbbls)	8,214	11,979	12,852	3,394	4,994	5,430
Gas reserves						
From production to planned for development (mmcf)	365,943	562,324	647,179	171,008	264,258	306,686
Income Data (US$'000)						
Future Gross Revenue	—	—	—	966,197	1,503,509	1,739,202
Deductions	—	—	—	885,986	1,108,472	1,136,631
Undiscounted Net Present Value (NPV)	—	—	—	80,211	395,037	602,571
Discounted NPV 10 Post Tax (10%)	—	—	—	137,867	259,472	334,258

Source: BKR CPR, page 3.

4. Summary of historic BKR Assets production by product volume and sales value

The following tables summarise the historic BKR Assets production volumes by product and the sales values of each product type for the years ended 31 December 2014, 31 December 2015 and 31 December 2016 and the six months ended 30 June 2017, all net to BP.[16] This information has been based on information extracted from BP's SAP systems and has been prepared by the Company.

	Six months ended 30 June 2017	**Year ended 31 December 2016**	**Year ended 31 December 2015**	**Year ended 31 December 2014**
Production volumes				
Oil (mboe)	321	628	682	298
NGL (mboe)	249	279	200	360
Gas (mmcf)	18,068	23,756	24,788	9,119
Total production mboe	**3,685**	**5,003**	**5,156**	**2,230**

	Six months ended 30 June 2017	**Year ended 31 December 2016**	**Year ended 31 December 2015**	**Year ended 31 December 2014**
Revenue by product	*US$'000*	*US$'000*	*US$'000*	*US$'000*
Oil	16,295	28,865	30,296	17,495
NGL	8,281	8,568	4,487	17,099
Gas	101,295	112,768	171,044	83,849
Other	4,188	8,835	2,064	(344)
Revenue	**130,059**	**159,036**	**207,891**	**118,098**

16 In respect of BP's interest in the Bruce field, calculated on the basis of a 37% interest.

5. Further detail on BKR Assets

5.1 Bruce Field: Serica UK 36% (subject to Completion)

The Bruce field is operated by BP and, upon Completion, will be operated by Serica UK, with partners Total E&P UK Limited (43.25%), BHP Billiton Petroleum Great Britain Limited (16%) and Marubeni Oil and Gas (North Sea) Limited (3.75%). BP has the remaining 37% interest in the field, and will retain a 1% interest following Completion. The Bruce field was discovered in June 1974 and is located in the UK Northern North Sea, 350 km northeast of Aberdeen at a water depth of 122 metres and with an area of approximately 75km^2. Production is primarily gas with associated condensate and oil.

Field development was sanctioned in 1990 and production started in May 1993. The field produces from 11 reservoir units, separated by faulting and in 2017 has had a cumulative production since 1993 of over 3tcf. Production in the first half of 2017 was approximately 4,400 boepd[17] net to BP of which approximately 85% is gas. The field utilises three platforms and a subsea manifold for production. Gas compression was installed in 2004.

Wet gas from the Bruce, Keith and Rhum fields is processed at the Bruce complex and then transported via a 6km spur line through the Frigg pipeline (owned and operated by North Sea Midstream Partners) to St. Fergus for Natural Gas Liquids extraction. Dry gas is delivered as part of a commingled gas stream at St. Fergus into the National Transmission System. NGLs are extracted at St Fergus and transported via a 12-inch diameter, 22 km pipeline to Cruden Bay. The condensate is separated at the Bruce complex then exported via a 24-inch diameter line, 254km to the Forties Unity platform. The liquids are then transported via the 36 inch diameter Forties pipeline 240 km to Cruden Bay, then overland to Grangemouth.

The Bruce field facilities comprise three bridge-linked platforms. There is a production platform housing a crew of up to 168 with production and utilities equipment. The second platform is a drilling platform, with the third platform hosting reception and compression facilities. Production from Bruce is commingled from five sandstone reservoir layers in the Middle Jurassic Bruce group. The reservoir structure is quite complex and highly compartmentalised, with eleven primary fault blocks, all considered to be isolated and independent from each other.

The field was originally appraised with 26 wells. Development commenced in 1990 with first production in 1993. To date there are over 60 well penetrations in the field with 21 producing wells. There are plans to hydraulically fracture two or more wells on Bruce, which the Directors anticipate will increase production rates and add Reserves. Subject to Completion Serica plans to review the potential for further hydraulic fracturing and infill drilling.

The BKR CPR (page 3) shows the following net remaining Reserves to BP (36%) on the Bruce field (allowing for the 1% interest being retained by BP) as of 1 June 2017:

- Net 1P Reserves: 6.7 mmboe; and
- Net 2P Reserves: 9.6 mmboe.[18]

5.2 Keith Field: Serica UK 34.83% (subject to Completion)

The Keith field lies 6.8 km to the southwest of the Bruce field in a water depth of 120 meters and has been developed as a subsea tie-back to the Bruce complex. It is operated by BP and, on Completion will be operated by Serica UK (34.83%) with partners Total E&P UK Limited (25%), BHP Billiton Petroleum Great Britain Limited (31.83%) and Marubeni Oil and Gas (8.34%). Keith was confirmed as a separate field to Bruce after drilling in 1987 and first came on production in 2000, with a second phase of development in 2002. The Keith field's production in the first half of 2017 was approximately 450 boepd net to BP.[19] No further capital programmes are planned on Keith as the field is in the final stages of its producing life. Subject to Completion, Serica UK intends to continue production from its single well as long as economically viable, but the well is currently scheduled to cease production in 2019. The reservoir units in the field primarily include the Beryl Embayment Group. The reservoir horizons are located within fault compartments, dip closed to the north and fault closed to the south east and west.

The BKR CPR (page 4) shows the following net remaining Reserves to BP on the Keith field as of 1 June 2017:

17 Calculated on the basis of a 36% interest in the Bruce field.
18 The Reserves figures are shown on an equivalent unit basis where natural gas is converted to oil equivalent.
19 OGA Production Statistics H1 2017.

- Net 1P Reserves: 0.37 mmboe; and
- Net 2P Reserves: 0.38 mmboe.[20]

5.3 **Rhum Field: Serica UK 50% (subject to Completion)**

The Rhum Field lies in the Northern North Sea 380 km north east of Aberdeen, 44 km north of the Bruce field and in 109 metres of water. The Rhum field is operated by BP, and will upon Completion be operated by Serica UK, with Iranian Oil Company (U.K.) Limited (50%) as its partner. The field was discovered by BP in 1977 and encountered high pressure and high temperature gas. Production started in December 2005 and peaked at 300 mmscfd (approximately 51,000 boepd) shortly after start-up. Cumulative production since 2005 has been 65 million boe gross, and in the first half of 2017 the field's gas and condensate production was approximately 13,500 boepd net to BP from two wells. The field produces gas and condensate from late Jurassic thinly bedded turbidite sand reservoirs. Gas produced from Rhum has a high CO_2 content, creating a requirement for gas blending at the St Fergus gas terminal prior to deliveries into the National Transmission System. The Rhum owners pay a fee for gas blending. A proposal has been made to increase the permitted levels of CO_2, in the gas delivered to the National Transmission System at the St Fergus gas terminal, which would remove the need for gas blending. A decision is expected from the relevant authority, Ofgem, before the end of 2017. If increased levels of CO_2 are permitted, gas blending fees would no longer be incurred by the Rhum owner. There would also be a reduced risk of interruptions to Rhum production owing to the availability of blending gas, which has, from time to time in the past, impacted on sales of Rhum field gas.

Production was shut-in in November 2010 as a result of European Union sanctions applied to the Iranian Oil Company (U.K.) Limited but was restarted in October 2013, when DECC took temporary management of IOC's share of the field in accordance with the Hydrocarbons (Temporary Management Scheme) Regulations 2013. Control of this share was returned to IOC in 2016 following the lifting of European Union sanctions and "secondary sanctions" imposed by the United States government. United States Government "primary sanctions" remain in place and BP, as the current operator of the Rhum field, has obtained a licence granted by OFAC for certain US persons and non-US entities owned or controlled by US persons to provide services for Rhum field operations. The licence was renewed in September 2017 and does not expire until September 2018. Serica UK will apply for an equivalent licence from OFAC prior to Completion (as BP's OFAC licence is not assignable), and the Acquisition Agreement is conditional on such a licence being received. In addition, owing to sanctions, BP has encountered difficulties in maintaining banking arrangements for receiving Rhum field cash calls payable by IOC. The Directors believe that banking arrangements can be established to resolve this issue, but the Acquisition Agreement is conditional upon Serica putting in place satisfactory banking arrangements prior to Completion that allow it to receive payments from and make payments to IOC as a partner in the Rhum field. Shareholders' attention is drawn to the risk factors in relation to the consequences of IOC being a partner in the Rhum field on page 42 of Part IV (*Risk Factors*).

The field produces from two wells. A third well (Rhum R3 Well) was drilled but not brought into production due to complications with the completion and hydrate formation. The Rhum field partners are planning that the Rhum R3 Well be re-entered and completed for production in 2018.

Rhum is a subsea development with the Rhum wells tied back to the Bruce platform complex which lies 44 km to the south of Rhum. The gas is processed at the Bruce complex then transported through the Frigg pipeline to St. Fergus for NGL extraction. The condensate is separated at the Bruce complex and then exported through the Forties Pipeline System to Cruden Bay.

The Rhum field is defined by two major north south trending faults that form a terrace which is overlaid with the reservoir units. These are Upper Jurassic Turbidite sands deposited within the Kimmeridge clay. Ryder Scott assumes that Rhum will continue producing until 2023 for 1P and 2026 for 2P Reserves. Field Ultimate Recovery Factor is estimated to be between 65% and 68% of gas in place (BKR CPR, page 45). Subject to Completion, Serica plans to seek opportunities to further increase the percentage recovery of gas in place.

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20 The Reserves figures are shown on an equivalent unit basis where natural gas is converted to oil equivalent.

The BKR CPR (page 4) shows the following net remaining Reserves to BP on the Rhum field as of 1 June 2017:

- Net 1P Reserves – 25.8 mmboe,
- Net 2P Reserves – 40.5 mmboe and
- Net 3P Reserves – 48.3 mmboe.[21]

21 The Reserves figures are shown on an equivalent unit basis where natural gas is converted to oil equivalent.

PART III – FURTHER INFORMATION ON SERICA

1. Introduction

Serica is the parent company of an independent oil and gas exploration and production group with a mixture of production, development and exploration interests. Serica traces its origins back to 2000, and following a number of corporate transactions was admitted to AIM in December 2005.

Serica's current major focus is in the Central North Sea where it has an 18% interest in the producing Erskine field and a 50% interest in the Columbus development where it is operator. The Columbus field has been appraised with four wells and is planned to be developed with a single production well.

Serica also has exploration interests at the Rowallan prospect in the Central North Sea, the Slyne Basin and the Rockall Basin offshore Ireland and in the Luderitz Basin offshore Namibia.

Serica has drilled 17 wells as operator in places as diverse as the North Sea, Indonesia and the Atlantic Ocean offshore Ireland and operated one of the largest 3D seismic surveys undertaken offshore Namibia.

2. Group structure and history

Petroleum Development Associates (Oil and Gas) Limited, a privately held oil and gas exploration and production business, was founded in June 2000 to acquire licences principally in the North Sea, subsequently expanding into Indonesia and Spain.

In January 2004, Petroleum Development Associates (Oil and Gas) Limited and Kyrgoil Holdings Corporation, a company that had been listed on the TSX Venture Exchange, merged to form a new company, Serica Energy Corporation. The common shares of Serica Energy Corporation were listed on the TSX Venture Exchange.

In August 2004, Serica Energy Corporation raised CAD$11 million through a private placement of warrant instruments in conjunction with the acquisition of Firstearl Limited. Antony Craven Walker joined the Group as non-executive Chairman and Neil Pike as a non-executive director.

In January 2005, Serica Energy Corporation received CAD$10.8 million through the exercise of warrants by its shareholders. In September 2005, the Company became the new holding company of the Serica Group by way of a share exchange agreement and in December 2005 the Company's shares were admitted to AIM in conjunction with an equity raise of £64 million. In October 2005, Serica announced that its Kambuna-2 appraisal well in the Glagah Kambuna TAC offshore North Sumatra had successfully tested 17.5 mmscf of gas and 1,500 of condensate per day.

The Columbus discovery well, 23/16f-11, completed in November 2006, tested gas and condensate followed by a successful appraisal programme in November 2007. Also in November 2007, a US$100 million senior secured borrowing facility was arranged with JPMorgan Chase as lead arranger.

A US$49 million equity raise was completed in January 2008 and in July 2008, the Serica Group sold a 15% interest in the Kambuna field development for US$53 million. Following the achievement of first production from the field in August 2009, the Serica Group sold a further 25% interest in Kambuna, together with other South-East Asian exploration interests, for US$99 million in January 2010. Kambuna ceased production in the second half of 2013.

In October 2013, the Company completed an equity raise of US$19.5 million through a placing and open offer.

In June 2014, the Serica Group announced the acquisition of an 18% interest in the North Sea producing Erskine field, located in the UK Central North Sea, from BP Exploration Operating Company Limited and Britoil Limited. The acquisition completed in June 2015. Under the terms of this acquisition, the consideration amounted to US$11.1 million in cash and 13.5 million new Ordinary Shares (reduced from the original share consideration of 27 million new Ordinary Shares due to the impact of certain adjustments on completion). The cash consideration was payable in four equal annual instalments, the first instalment having been settled at completion. The final instalment is payable on 1 July 2018.

During 2016 and 2017 the Serica Group has progressed Columbus development planning, given extra impetus by the OGA's Maximising Economic Recovery programme, and worked on the selection of one out of two separate potential off-take routes.

3. Summary of Licences

3.1 Erskine

Asset	Operator	Serica Interest (%)	Status	Licence Expiry[1]	Licence Area (km^2)
P.057, Block 23/26a (Area B)	Chevron North Sea Limited	18	Production	—	4
P.264, Block 23/26b (Areas B and C)	Chevron North Sea Limited	18	Production	—	23

Note:
(1) Continues to cessation of production.

3.2 Columbus

Asset	Operator	Serica Interest (%)	Status	Licence Expiry	Licence Area (km^2)
Licence P.101, Block 23/21a	Serica UK	50	Development	—[1]	9
P.1314, Block 23/16f	Serica UK	50	Development	December 2031	22

Note:
(1) Licence P.101 is currently renewed on a rolling basis.

3.3 Rowallan

Asset	Operator	Serica Interest (%)	Status	Licence Expiry	Licence Area (km^2)
P.1620, Block 22/19c	ENI (UK) Limited	15	Exploration	June 2035	75

3.4 P.2124

Asset	Operator	Serica Interest (%)	Status	Licence Expiry	Licence Area (km^2)
P.2124, Block 113/22a	Zennor North Sea Limited	20	Exploration	December 2039	121.1

3.5 **Slyne**

Asset	Operator	Serica Interest (%)	Status	Licence Expiry	Licence Area (km^2)
FEL 1/06	Serica Slyne	100		December 2023	305
Achill Prospect, Block 27/9			Exploration		
Bandon Discovery, Block 27/4			Development		
Bandon South Prospect, Block 27/4			Exploration		
Boyne Prospect, Blocks 27/4 and 27/5			Exploration		
Liffey Prospect, Block 27/9			Exploration		

3.6 **Rockall**

Asset	Operator	Serica Interest (%)	Status	Licence Expiry	Licence Area (km^2)	Comments
1/09, Blocks 5/17 (part), 5/18, 5/22 (part), 5/23 (part), 5/27 (part) and 5/28 (part)	Serica Rockall	100	Exploration	20 July 2027	390.0	The first phase of Licence P1/09 expired on 20 July 2017. Confirmation has been received that the first phase of the licence will be extended, but as at the date of this document, the extension has not yet been formalised.
4/13, Blocks 11/10, 11/15. 12/1 (part), 12/6 and 12/11 (part)	Serica Rockall	100	Exploration	30 November 2030	925.0	

3.7 **Namibia**

Asset	Operator	Serica Interest (%)	Status	Licence Expiry	Licence Area (km^2)
Blocks 2512A, 2513A, 2513B and 2612A (part)	Serica Namibia	85	Exploration	19 December 2018	17,384

4. Summary of Reserves and Resources

The following tables summarise the Reserves and resources of Serica. This information has been extracted from the Serica CPR, which can be found in its entirety in Part VI (*Competent Person's Report on Serica*).

Summary of estimated net Reserves attributable to Serica's interest in the Erskine field (as at 30 June 2017)

	Total 1P	Total 2P	Total 3P
Net Remaining Reserves			
Oil (mbbl)	820.7	1,498.5	2,323.1
NGL (mbbl)	107.6	195.3	301.3
Gas (mmcf)	5,414.8	9,825.5	15,163.9

Source: Serica CPR, Technical Discussion, page 3.

Summary of net unrisked contingent resources(1) attributable to Serica's interest in the Columbus Field (as at 30 June 2017)

			2C Contingent Resources	
Field	**Operator**	**Risk Factor(2) (%)**	**Oil (mbbl)**	**Gas (mmcf)**
Columbus Field	Serica Energy (UK) Limited	85	1,396.9	31,766.6

Source: Serica CPR, Technical Discussion, page 5.

Notes:

(1) These volumes represent only the portions of the reservoirs that lie within the boundary of the lease area.

(2) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this table, the risk factor for the contingent resources refers to the PRMS term "chance of development".

5. Further details on Serica assets

5.1 Production

Central North Sea: Erskine Field – Serica UK 18%

All of Serica's current production comes from Erskine, a gas and condensate field located in the Eastern Central Graben, UK Central North Sea and acquired from BP in June 2015. Serica UK's partners are Chevron North Sea Limited 50% (operator) and Chrysaor Limited 32%. Field facilities comprise a normally unmanned platform, remotely controlled from the Lomond platform, with five wells producing primarily from the Pentland Sandstone with further contribution from the Erskine and Heather sands. Erskine commenced production in December 1997, and since then has produced approximately 120 mmboe (gross).

Erskine gas and fluids are transported via a 30km pipeline to the Lomond platform, which is 100% owned and operated by Chrysaor Limited, for processing and separation into condensate and gas. Serica UK's condensate allocation is transported through the Lomond to Everest condensate offtake line and then into the Forties Pipeline System before being sold as Forties crude oil at the Cruden Bay terminal. Erskine gas is transported via Lomond to the Central Area Transmission System (riser tower at North Everest) and then through the CATS system before being sold at the CATS terminal on Teeside.

Erskine wells have demonstrated capability to produce over 3,500 boepd net to Serica UK when unconstrained by planned or unplanned shut-ins or export pipeline restrictions. Average daily production in 2016 was 1,631 boepd (net to Serica UK) including a six-month shut-in for treatment of a wax blockage in the Lomond to Everest condensate export line and maintenance work. Production in the first half of 2017 averaged approximately 2,800 boepd net to Serica UK. Production during the second half of 2017 is expected to be lower due to an eight week shut-in for maintenance work on Lomond coinciding with a planned maintenance programme of the Forties Pipeline System and then continuing work to clear the condensate export line of wax deposits. Since recommencement of production on 22 September 2017 to 22 November 2017 (the latest date for which figures are available) the field has delivered at an average rate of approximately 2,450 boepd net to Serica UK. The operator of the Lomond platform has commenced pigging operations to clear the line which, if successful, will enable the Erskine field to increase production levels to the field's full potential.

The Serica CPR (Technical Discussion, page 3) shows the following net remaining Reserves to Serica UK on the Erskine field as of 30 June 2017:

- Net 1P Reserves: 1.83 mmboe; and
- Net 2P Reserves: 3.33 mmboe.[22]

The Serica CPR indicates that Erskine 2P Reserves will be sufficient to keep the field operating until the end of 2022.

5.2 **Development**

Central North Sea: Columbus Field – Serica UK 50%

The Columbus gas condensate field is located in close proximity to the Lomond platform, which is the offtake route for production from Serica UK's Erskine producing interest. Serica UK is Columbus field operator with partners EOG Resources United Kingdom Limited (25%) and Endeavour Energy UK Limited (25%). The field is located in the Eastern Central Graben, UK Central North Sea and the reservoir is located within the Forties Sandstone.

The Columbus field has been appraised with four wells and is planned to be developed with a single production well. Serica UK is currently working towards a full field development plan for submission to the Oil and Gas Authority by mid-2018 with a view to commencing development work before the end of 2018. First gas is currently targeted for 2020.

Serica UK is progressing two development options for Columbus. One option is an extended-reach development well drilled into Columbus from the Lomond platform, located 5 kilometres away. The other option is drilling a subsea well and joining a potential future development of the nearby Arran field to the Shearwater platform, located 35 kilometres from Columbus.

Studies into drilling an extended reach well from the Lomond platform have been carried out and have successfully demonstrated feasibility and satisfied the Lomond platform operator that it passes their internal HSE and operational requirements. Serica UK is now working to progress commercial terms with the host operator. This route offers the potential to accelerate the first production date by a year or more, compared to the alternative route, as it does not require pipelines or subsea equipment, and involves few parties. It brings additional potential benefits of deferring the date of Lomond and Erskine abandonment and attracting further third party fields to the hub.

In parallel, Serica UK is working with the Arran field operator to appraise the option of tying Columbus into a proposed new pipeline running from Arran to the Shearwater platform. A joint FEED (Front End Engineering Design) Study between the Arran and Columbus owners is ready to start and discussions on commercial terms are making good progress. The advantage of this route are the opportunity to share capital costs with the Arran owners and share operating costs with the other parties producing over the Shearwater platform. It also involves a shorter drilling programme.

The Serica CPR (Technical Discussion, page 5) shows the following net 2C contingent resources to Serica on the Columbus field to be 6.7 mmboe.[23]

5.3 **Exploration**

Central North Sea: Rowallan Prospect: Serica UK 15%

Block 22/19c is located in the Central North Sea, around 20km west of the Columbus field. It contains the Rowallan Prospect comprising potential condensate targets in the Triassic Skagerrak and the Middle Jurassic Pentland formations. Partners comprise ENI UK Limited (operator – 40%), JX Nippon Exploration and Production (U.K.) Limited (25%) and Mitsui E&P UK Limited (20%).

Well preparations for the Rowallan Prospect are underway, with spending on a site survey and long-lead items approved by partners for 2017. A vessel is due to be deployed in December 2017 to perform a site survey in preparation for the drilling of a well in 2018. The prospect is located within Serica UK's core Central North Sea area, close to Erskine and Columbus. Serica UK is fully carried on all costs for a well on this high pressure, high temperature prospect.

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22 The Reserves figures are shown on an equivalent unit basis where natural gas is converted to oil equivalent.

23 The resources figure is shown on an equivalent unit basis where natural gas is converted to oil equivalent.

The Serica CPR (Technical Discussion, page 8) shows the net Best Estimate prospective resources to Serica UK on the Rowallan Prospect to be 19.7 mmboe.[24]

East Irish Sea: Serica 20%

Serica holds a 20% non-operated interest in Block 113/22a following the recent relinquishment of its interests in Blocks 113/26b and 113/27c. This licence is also expected to be relinquished as soon as permission is granted from the UK authorities, which is expected in late 2017.

5.4 **Ireland**

Slyne Basin: Serica 100%

Serica has increased its equity from 50% to 100% following the withdrawal of DEA Deutsche Erdoel AG from the licence in September 2017 and has secured a two-year extension to further explore the potential first identified through the Bandon oil discovery drilled in 2009. In that time, Serica plans to further de-risk the Boyne prospect, down-dip of Bandon, by detailed analysis to better predict the oil type likely to be found in the Jurassic and Triassic sandstone formations.

Serica is seeking to identify a farm-in partner to share drilling and development costs of the Boyne prospect and, in the event of a commercial discovery, to follow with a development to bring the field on production. The Best Estimate prospective resources estimate of approximately 51 million barrels of oil equivalent is anticipated by the Directors to result in an attractive economic development at current oil prices.

The Serica CPR (Technical Discussion, page 8) shows the following net prospective resources to Serica on the Boyne Prospect as of 30 June 2017:

- Low estimate; 16 mmboe;
- Best estimate: 51 mmboe; and
- High estimate: 168 mmboe.[25]

Rockall Basin: Serica 100%

Serica has extensive acreage in the Rockall Basin offshore Ireland. It has secured a two-year extension on licence 4/13 and aims to bring in a partner to join in drilling an exploration well. The well is designed to test two prospects, the shallower prospect being a Cretaceous fan defined by seismic anomaly and analogous to prospects identified in the Porcupine basin. This overlies a deeper target, a structural fault block of Permian/Triassic age, analogous to the nearby Dooish discovery. Serica estimates Best Estimate prospective resources for these stacked prospects to be in the order of 2.7 tcf of gas and 178 million barrels of condensate, which would result in a major development.[26]

Licence 1/09 contains a large structural prospect, Muckish, also a Dooish analogue, and Serica is seeking a partner to drill a well to prove the concept, ideally as part of the same drilling programme as 4/13.

In the remainder of 2017, further work is planned on the licences to investigate the potential for productive fractured basement. The recent Lancaster discovery by Hurricane in the West of Shetlands area has proved the production capability of fractured basement.

5.5 **Namibia**

Luderitz Basin: Serica 85%

Serica has progressed to the first renewal period of the licence, which runs until the end of 2018. The partners are National Petroleum Corporation of Namibia (Pty) Limited 10% and Indigenous Energy (Pty) Limited 5%. This licence period does not include a commitment to drill a well. The 3D seismic data, from a major seismic programme operated by Serica, has identified giant carbonate prospects as well as large, more conventional Cretaceous submarine fan prospects supported by seismic anomalies. The drilling of a well will be subject to the introduction of a new partner to meet a significant proportion of the costs. Serica plans to work on identifying more prospects supported by the latest seismic visualisation techniques as well as seeking a partner to drill the main carbonate prospect.

24 The resources figure is shown on an equivalent unit basis where natural gas is converted to oil equivalent.
25 The resources figures are shown on an equivalent unit basis where natural gas is converted to oil equivalent.
26 These estimates are management estimates only and are not supported by a competent persons report.

6. HSE

HSE is central to Serica's core values. As part of the Acquisition, the Company will develop and seek approval for a safety case relating to its operatorship of the BKR Assets.

Serica commits to ensuring a safe and healthy working environment in line with current best practices. The Company has always rigorously observed health and safety standards, laws and regulations in the areas in which it has operated, and ensures that its employees and consultants receive appropriate training and guidance to enable them to carry out their tasks in a safe and competent manner.

Serica acts with care and sensitivity towards the local environment in which it operates and has implemented a systematic approach to the management of occupational, environmental and community risk.

Serica encourages employees and stakeholders to immediately report to management any aspect of the Company's business or operations which is considered to actually or potentially not meet its high standards.

PART IV – RISK FACTORS

Any investment in the Company is subject to a number of risks. Accordingly, investors and prospective investors should carefully consider all of the information set out in this document including, in particular, the risks described below. The Group's and, following Completion, the Enlarged Group's business, financial condition or results of operations could be materially and adversely affected by any of the risks described below. In such cases, the market price of the Ordinary Shares may decline and investors may lose all or part of their investment.

These risks should not be regarded as a complete and comprehensive statement of all potential risks and uncertainties nor are they listed in order of magnitude or probability. Additional risks and uncertainties that are not presently known to the Directors, or which they currently deem immaterial, may also have an adverse effect on the Enlarged Group's operating results, financial condition and prospects. The risk factors described below are as of the date of this document and, except as required by the AIM Rules or any other law or regulation, will not be updated.

Investors and prospective investors should consider carefully whether an investment in the Company is suitable for them in light of the information set out in this document and the financial resources available to them.

US Shareholders are recommended to seek their own advice as to whether they are entitled to vote on the Resolution in view of US primary sanctions imposed in relation to Iran and IOC being a partner in the Rhum Field.

1. Risks Relating to the Acquisition

The Acquisition may not complete and there are operational risks associated with the BKR Assets

Completion of the Acquisition Agreement is subject to various conditions precedent, including various consents and approvals being obtained including consent to the Acquisition from the OGA. If any of such conditions are not satisfied (or, where possible, waived), Serica will not be able to complete the Acquisition. Certain of the conditions, and in particular the approval of the OGA, are anticipated to take some months to satisfy. Accordingly, it is not expected that the Acquisition will be completed until sometime in mid- 2018. Due to the length of time that will elapse before the last of the conditions is satisfied, there is an increased risk that either the conditions are not satisfied, or that the Acquisition Agreement is terminated prior to completion in accordance with its terms.

If any of the conditions are not satisfied (or waived, if applicable), or if the Acquisition Agreement is terminated in accordance with its terms, then the Acquisition will not be completed, which would mean that substantial costs would have been incurred by the Company with none of the potential benefits of the Acquisition having been achieved. It would also mean that management time spent in connection with the Acquisition, which could have otherwise been spent in connection with other aspects of the Company's business, will not have been spent productively.

Although the Company has carried out legal, accounting, technical and commercial due diligence on the BKR Assets, in the event that such enquiries or subsequent responses were insufficient, the Company may not have been able to assess properly the risks associated with, and the value of, the BKR Assets. In addition the BKR Assets and infrastructure is being acquired on a sight as seen basis and some, notably the Bruce platform and related infrastructure is ageing and may need unexpected and unbudgeted material works undertaken to continue in operation and the scale of such works may be extensive and costly.

The Company has negotiated what it considers to be appropriate warranty protection under the Acquisition Agreement, but provisions in the Acquisition Agreement may be unenforceable or may be insufficient to cover potential liabilities relating to the BKR Assets and, as a result, the value of the BKR Assets may be less than the amount that the Company pays for them, although this has been mitigated in the structure of the Acquisition, as most of the consideration due to BP is deferred/ contingent, and will only become payable to the extent the BKR Assets generate positive cashflows.

The field partners for the Bruce and Keith fields, which are different to the field partner for the Rhum field, could have different objectives which may lead to challenges as all fields share the same infrastructure

The Bruce platform controls, processes and transports products from the Bruce, Keith and Rhum fields. It has been operating since 1993 and so needs a continuing programme of maintenance to ensure full operating capability. The Rhum field has the greatest production potential out of the BKR Assets, but the Rhum partner, Iranian Oil Company (UK) Limited, is different to the field partners at Bruce and Keith, who accordingly could have different objectives which may lead to challenges in approving increases in investment in the Bruce wells and infrastructure. This could reduce or delay access to the upside potential in relation to the BKR Assets. A failure by the Enlarged Group to manage these risks could have a material adverse effect on the Enlarged Group's financial condition, results of operations or prospects.

If the existing field partner exercises its pre-emption rights in relation to the Rhum field, the Acquisition may not be completed

The Joint Operating Agreement in relation to the Rhum field provides the partner (Iranian Oil Company (UK) Limited) the right to pre-empt any offer from a third party through matching the terms of such offer. The proposed acquisition of the BKR Assets by the Company will trigger this right. Accordingly, in the event that Iranian Oil Company (UK) Limited were to exercise this right within the time periods permitted by the Joint Operating Agreement, BP would be obligated to accept such offer which may mean that the Acquisition would not be completed, as the Acquisition Agreement provides that Serica will not acquire the BKR Assets unless it acquires the Rhum field. The field partners to BP on the Bruce and Keith fields do not have a pre-emption right under the respective joint operating agreements, but they do have a right to submit offers following BP notifying them of its intention to sell, although BP is under no obligation to accept such offers. Shareholders' attention is drawn to the summary of the Acquisition Agreement at paragraph 11.1(b) of Part XII (*Additional Information*).

The existing field partners to the BKR Assets may object to the transfer of operatorship to Serica, which may mean the Acquisition would not be completed

Under the respective joint operating agreements in relation to the BKR Assets, BP's partners (being Total E&P UK Limited, BHP Billiton Petroleum Great Britain Limited, Marubeni Oil and Gas (North Sea) Limited and Iranian Oil Company (UK) Limited) have certain rights regarding the transfer of operatorship to a new partner. They will require demonstration of the financial and operational capability of a new partner to meet its obligations. Operatorship of the BKR Assets is intended to transfer to Serica UK pursuant to the Acquisition. Accordingly, the BKR Assets field partners need to be satisfied that Serica UK, as the new operator of the BKR Assets has the financial capability to meet its obligations as operator. Serica UK is confident that it has the financial and operational capability to meet the ongoing obligations as operator in relation to the BKR Assets. However, should any of the partners not be so satisfied, then they could oppose the transfer of the BKR Assets to Serica UK and the Acquisition may not be completed. The Acquisition Agreement is conditional upon the approval of BP's partners in the BKR Assets to the assignment of the licence interests and the transfer of operatorship to Serica UK.

The Acquisition of the BKR Assets by Serica requires the approval of the UK Oil & Gas Authority

Serica UK requires approval from the OGA to assume operating responsibilities on the BKR assets. The OGA will wish to satisfy itself as to Serica UK's financial capacity to participate in licence operations and to discharge its licence obligations. This will involve Serica UK demonstrating this to the OGA based on its financial condition, its future expectations for the fields and the terms of the Acquisition. The OGA must also approve the transfer of operatorship which it will determine in conjunction with the Offshore Safety Directive Regulator where the focus will be on technical and financial competence. It is anticipated that such approval could take some months to obtain. Such approval is a condition precedent for Completion and, accordingly, if not received the Acquisition will not complete.

Licences P.209 and P.198 in relation to the Bruce, Keith and Rhum fields need to be renewed before Completion. If they are not renewed, Completion will not occur

Licences P.209 and P.198 in relation to the Bruce, Keith and Rhum fields expire in March 2018. BP has applied for the licences to be renewed before Completion, and their renewal is a condition precedent in the Acquisition Agreement. The Directors have no reason to believe that the licences will not be renewed, but if they were not to be renewed, the condition would not be satisfied, in which event Completion will not occur.

The decommissioning security agreements in relation to the Bruce and Keith fields will require amendment which will be subject to the approval of BP's partners on the Bruce and Keith fields

Pursuant to the Acquisition Agreement, BP has agreed to retain the decommissioning liability in relation to the existing facilities on the BKR Assets. In light of this obligation, the decommissioning security agreements in relation to the Bruce and Keith fields will need to be amended and such amendments will be subject to the approval of BP's partners on the Bruce and Keith fields. The Acquisition Agreement is conditional upon such approvals being obtained. Were they not to be obtained, Completion would not occur. Further, the parties have agreed that BP shall control the voting rights of Serica UK in relation to decommissioning matters that concern existing facilities. While Serica UK's interests in relation to decommissioning are likely to be aligned to BP's interests, BP could vote in a way which is not in the best interests of Serica UK.

The Company will need to engage a large number of contractors to manage operations relating to the BKR Assets following Completion

The BKR Assets engage a significant number of contractors to provide services in relation to its operations. Services are provided by either BP itself, outside third party contractors or other companies within the BP Group, with many operations being provided by internal BP providers. Many of these contracts are not assignable, and many of the services provided by BP and BP Group companies will not be provided by them following Completion. Serica UK and BP have entered into the Transfer of Operatorship Agreement to *inter alia* assist in the planning for the management of engaging replacement contractors. Accordingly, in the period between the execution of the Acquisition Agreement and Completion, Serica UK will need to agree terms with new contractors to provide services in place of these existing contractors. This is likely to be a substantial task which, if not managed successfully, would result in the OGA and the BKR Asset partners not approving the transfer of the operatorship of the BKR Assets to Serica UK. Without such approval, the Acquisition will not be completed.

The Enlarged Group's future prospects will, in part, be dependent on effective integration of the BKR Assets into the Group, including with respect to employees and operational systems

The Enlarged Group's future prospects will, in part, be dependent upon the Enlarged Group's ability to integrate the BKR Assets into the Group successfully and any other businesses that it may acquire in the future without material disruption to the existing business including as a result of the integration of operational systems. The performance of the Enlarged Group will, amongst other things, also depend on the successful transfer, integration, retention and motivation of employees within the Enlarged Group. The Acquisition represents a significant undertaking for the Group as it will take on operatorship of the BKR Assets, including increasing the number of its employees from less than ten to over 100. Were some of the employees to choose not to transfer to the Group, Serica would need to recruit alternative employees from the oil and gas industry. Were such personnel not to be available, the transfer of operatorship to Serica UK, and therefore Completion, could be delayed. In addition, the Group expects to recruit an additional approximately 20 employees beyond those who will transfer across with the BKR Assets. The Company will need to implement a significant implementation plan to manage the integration of the new employees, including the operational systems associated with significantly increasing the number of employees. This will include upgrading the Group's IT, human resources and HSE systems. The Group will also need to expand its reporting, treasury and risk management systems. The Group will open a new office in Aberdeen whilst retaining its office in London. This will bring the challenge of managing different locations. Serica UK and BP have entered into the Transfer of Operatorship Agreement which sets out the process by which the parties will develop and implement a plan to transition the operatorship of the BKR Assets to Serica UK which is summarised at paragraph 11.1(g) of Part XII (*Additional Information*). A failure to successfully manage the integration of the BKR Assets could have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

The cost of replicating BP benefits for the employees who transfer to the Group could be more than anticipated by Serica

The Group has agreed with BP to protect the terms and conditions of those employees of BP who transfer across to Serica above and beyond TUPE requirements for a period of at least 12 months following Completion. This will necessitate Serica providing similar defined contribution pension, share scheme and other benefits for the employees. Serica has estimated the likely cost of providing such benefits, however, such benefits could cost more than is being anticipated by Serica. Were this to occur, then the additional cost could have a material adverse effect on the Enlarged Group's results of operations, financial conditions and prospects.

As a result of US primary sanctions against Iran the operations of the Rhum gas field could be adversely affected

The Rhum gas field is owned as to 50% by BP and as to 50% by Iranian Oil Company (UK) Limited, an ultimate subsidiary of National Iranian Oil Company ("**NIOC**"). Both the Iranian economy and NIOC in particular have been targeted by international sanctions in recent years. In January 2016, EU sanctions were largely lifted against Iran and NIOC, but US primary sanctions remain in force which amount to a comprehensive embargo on US persons having dealings with Iran. As a result of US primary sanctions, BP has continued to seek a licence from US authorities to provide dispensation for a small number of US contractors to provide services to the Rhum gas field from time to time and also to enable BP to potentially bring in US contractors in the case of emergency. BP's licence was renewed on 29 September 2017 and continues in force until 30 September 2018. Following Completion, Serica UK may still need to rely on a small number of US contractors to operate the Rhum field, although it may, over time, seek to reduce or eliminate their use completely. Between the date of signing the Acquisition Agreement and Completion, Serica UK will, whilst US sanctions remain in force, seek to obtain a licence from OFAC. The Acquisition Agreement is conditional upon such a licence being granted to Serica UK by OFAC. The Acquisition Agreement also contains provisions entitling Serica UK or BP to terminate it prior to Completion in the event that there is a cessation of production of the Rhum gas field owing to sanctions.

Further, before Completion there could be circumstances where Iranian related sanctions are detrimental to the operation of the Rhum gas field but which do not give rise to a cessation of production. In this event, Serica UK would not be entitled to terminate the Acquisition Agreement but the operations and performance of the Rhum gas field could nevertheless be materially affected. Furthermore, following Completion, OFAC could withdraw the grant of or not renew any licence provided to Serica UK and/or the US or EU sanctions regime against Iran could be amended or enhanced, which may make it more difficult or impossible for Serica UK to continue to operate the Rhum gas field. Should Serica UK, following Completion, cease to be able to operate the Rhum gas field, as a result of sanctions this would have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

The Acquisition Agreement is conditional upon satisfactory banking arrangements being put in place which allow payments to and from IOC in relation to the Rhum field

BP has encountered difficulties receiving payments from IOC in relation to Rhum operations such as cash calls due to the withdrawal of banking facilities owing to sanctions. The Directors believe that alternative banking arrangements can be established to resolve the issue, but the Acquisition Agreement is conditional upon Serica UK putting in place satisfactory banking arrangements prior to Completion that allow it to receive payments from and make payments to IOC as a partner in the Rhum field. In the event that satisfactory arrangements cannot be established and Serica UK does not waive the condition, Completion will not take place. BP has agreed to indemnify Serica UK under the Acquisition Agreement for any historic underpayments owed by IOC to BP up to the date of Completion.

The presence of IOC as a partner on the Rhum field and the associated risk of potential exposure to sanctions may deter some non-US contractors from providing services to support Rhum field operations

In addition to the restrictions related to US sanctions and the use of US contractors and personnel on Rhum operations, the presence of IOC as a partner on the Rhum field and the associated risk of potential exposure to sanctions may deter some non-US contractors and providers of other services from providing equipment and services to support Rhum field operations. This may restrict the Enlarged Group's flexibility in conducting Rhum operations, increase costs or delay operational and investment plans.

There is a risk that gas produced from the Rhum field might have to be blended or production shut in due to its high CO_2 content

Gas produced from the Rhum field has a high CO_2 content. Currently, the Rhum owners pay a fee for blending gas which is used to keep the commingled gas stream at the St Fergus terminal within the CO_2 threshold for entry into the National Transmission System. It is proposed to increase this threshold such that blending gas is not required, which would avoid the need for the Rhum owners to pay a blending fee. Approval from the relevant authority (Ofgem) is expected before the end of 2017. If approval is not received, or should such approval once granted be varied or withdrawn, then either blending gas would need to be identified which may add considerable cost for the Rhum owners, or Rhum production might have to be restricted or shut in. Were these events to materialise, this could have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

There is a dispute between BP's partner to the Rhum field and the Bruce field partners relating to Bruce field costs

Iranian Oil Company (UK) Limited is disputing with the Bruce field partners the switch triggered by the Bruce field partners from volume based tariffs to sharing overall costs of the Bruce facilities based on their respective proportionate production volumes. The matters in dispute to date will remain an issue between IOC and BP and the other Bruce field partners and will not transfer to Serica UK under the terms of the Acquisition. However, Serica UK would be exposed to IOC continuing to dispute after the effective date of the Acquisition (1 January 2018), the principle or details of a charge for the Bruce field costs. To the extent that the dispute continues after the effective date of the Acquisition (1 January 2018), this could have a material adverse effect on the Enlarged Group's results of operations, financial condition and prospects.

There is a certain amount of interdependency between the BKR Assets, such that matters affecting one field could affect the economic viability of the other fields

The infrastructure for the Keith and Rhum fields is tied back to the Bruce field infrastructure, and therefore production for the Keith and Rhum fields is reliant on the Bruce infrastructure which is ageing and requires substantial maintenance. A failure by the partners to the BKR Assets to maintain the Bruce infrastructure would also cause production for Keith and Rhum to cease, leading to premature abandonment, and a failure to realise the value for the BKR Assets. In addition, the Bruce field relies upon cost contributions and tariffs from the Rhum field to maintain profitability and if such contributions were to cease (for example because of a shut-in at the Rhum field due to sanctions), then the Bruce field, with substantial fixed costs, may not remain economically viable and may also be forced to cease production. A failure by the Enlarged Group to manage this risk would have a material adverse effect on the value of the BKR Assets.

The Sale and Purchase Agreement and the Security Agreements will place certain restrictions on the ability of the Enlarged Group to raise debt finance in the future

The Security Agreements provide certain security to BP in respect of its future cash flows from the BKR Assets, as set out at paragraph 11.1(f) of Part XII (*Additional Information*). In the event that Serica UK does not comply with its payment obligations to BP in relation to deferred consideration payable for the BKR Assets, then BP will be entitled to enforce its security which could result in BP, *inter alia*, taking back control of the BKR Assets. Furthermore, the Security Agreements could make it more challenging for the Enlarged Group to raise debt finance in the future as a result of the Enlarged Group not having available to it sufficient assets over which it will be able to offer first ranking security.

Additionally, the Sale and Purchase Agreement and the Security Agreements place restrictions on the ability of the Enlarged Group to encumber the BKR Assets. Accordingly, the Security Agreements may have an adverse effect on the ability of the Enlarged Group to raise debt finance.

The Sale and Purchase Agreement restricts Serica UK from selling interests in the BKR Assets without the approval of BP

Under the Sale and Purchase Agreement, Serica UK requires the approval of BP to sell interests in the BKR Assets. This will reduce the portfolio management options available to the Company, which could reduce the Enlarged Group's flexibility following Completion.

2. Operational risks relating to the Group and the Enlarged Group

The exploration for, and the development and production of, oil, gas and other natural resources is technically challenging and involves a high degree of risk

The operations of the Group and, following Completion, the Enlarged Group may be disrupted by a variety of risks and hazards which are beyond the control of the Group and, following Completion, the Enlarged Group, including environmental hazards, industrial accidents, occupational and health hazards, technical failures, labour disputes, political unrest and conflicts, unusual or unexpected geological formations, flooding, earthquake and extended interruptions due to inclement or hazardous weather conditions, explosions and other accidents. These risks and hazards could also result in damage to or destruction of wells, assets under development or production facilities, personal injury, environmental damage, business interruption, monetary losses and possible legal liability. The assets held by the Group and, following Completion, the Enlarged Group all relate to offshore licences. Exploration and production on offshore licences may significantly increase the risks involved compared to onshore licences. The risk may increase both regarding the probability that a shutdown or an accident occurs, and the consequence of such a shutdown or accident being more severe. In recent years, the Erskine field production has been subject to protracted interruptions due to failures of the Lomond facilities through which Erskine production is exported and to wax build-up in the Lomond to Everest condensate export line through which Erskine condensate is exported. Production from the Rhum field was interrupted from December 2010 to December 2014 due to sanctions imposed on Rhum partner IOC and production was restricted during 2016 whilst a blending solution was sought to mitigate the high CO_2 content of Rhum gas.

Given the Group and, following Completion, the Enlarged Group's focus on growth, some of its projects will require the construction and/or commissioning of production facilities and other forms of infrastructure and/or investment in existing infrastructure of the Group and, following Completion, the Enlarged Group to realise their full potential. The Enlarged Group will hold an interest in the undeveloped Columbus gas and condensate field offshore the UK. Delays in the construction and commissioning of this project and/or other technical difficulties may result in the Enlarged Group's current or future projected target dates for the delivery of this development project and for production being delayed or further capital expenditure being required. If the Enlarged Group fails to meet its work and/or expenditure obligations in relation to the Columbus gas and condensate field, the rights granted under the relevant licences may be forfeited.

The Group and, following Completion, the Enlarged Group will be subject to operational risks

The delivery of the Enlarged Group's production plans depends on the successful continuation of existing field production operations at the BKR Assets and at Erskine in the Central North Sea and the development of key projects, in particular Columbus in the Central North Sea, where the Group is operator. The Group also has interests in exploration licences in the UK, Ireland and Namibia. The continuation and development of these projects involves risks typically associated with such activities including blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, reservoir and other geological uncertainties, unusual or unexpected rock formations, abnormal pressures, availability of technology and engineering capacity, availability of skilled resources, maintaining project schedules and managing costs, as well as technical, fiscal, regulatory, political and other conditions. Such physical hazards can also severely damage or destroy equipment, surrounding areas or property of third parties as well as causing loss of life or serious injury to individuals. Damage or loss occurring as a result of such risks may give rise to claims against the Group and, following Completion, the Enlarged Group and may impair the Group's and, following Completion, the Enlarged Group's continuation of existing field production and delivery of key projects.

The Group and, following Completion, the Enlarged Group may face interruptions or delays in the availability of infrastructure, including downstream processing, pipelines and storage tanks, on which exploration and production activities are dependent. This infrastructure is subject not only to the risk of physical damage but in certain circumstances could also be dependent upon certain minimum economic thresholds being met which are governed by a combination of commodity prices and throughput often from other producing fields. If such third party infrastructure is no longer economic to operate it could lead to the cessation of production leaving the Group's and, following Completion, the Enlarged Group's fields stranded without a product export route. Such an event could lead both to a cessation of production and an earlier requirement to decommission relevant wells and infrastructure and incur significant associated decommissioning costs.

The production performance of the reservoirs and wells in which the Group and, following Completion, the Enlarged Group has interests may also be different to that forecast, due to normal geological or mechanical uncertainties. Interruptions, delays or performance differences could result in disruptions or adverse changes to the Group's and, following Completion, the Enlarged Group's production and projects, as well as increased costs.

The Group and, following Completion, the Enlarged Group may be at risk from uninsured hazards and/or uninsured liabilities

The Group and, following Completion, the Enlarged Group may be subject to substantial liability claims due to the inherently hazardous nature of its business or for acts and omissions of sub-contractors, operators or joint venture partners. Any indemnities the Group and, following

Completion, the Enlarged Group may receive from such parties may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources. Although the Group and, following Completion, the Enlarged Group intends to maintain insurance in accordance with industry practice, there may be circumstances where the Group and, following Completion, the Enlarged Group does not have, or cannot obtain, insurance to cover certain risks at a reasonable market premium, including business interruption insurance. In addition, there can be no assurance that the proceeds of insurance applicable to covered risks will be adequate to cover the relevant losses or liabilities. Accordingly, the Group and, following Completion, the Enlarged Group may suffer material losses from uninsurable or uninsured risks or insufficient insurance coverage which may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The Group and, following Completion, the Enlarged Group will be dependent on its executive management and technical staff

The Group and, following Completion, the Enlarged Group will be significantly dependent upon its executive management and senior employees. There is a risk that the unexpected loss of services of any such member of staff could have a material adverse effect on the Group and, following Completion, the Enlarged Group. The Group does not currently have any key person insurance in effect for management, but will consider putting in place such key person insurance following Completion. Attracting and retaining additional skilled personnel may be required to ensure development of the Group's and, following Completion, the Enlarged Group's business. The Group and, following Completion, the Enlarged Group will face significant competition for key skilled personnel in the oil and gas sector. Approximately 110 employees are expected to transfer across to the Enlarged Group with the BKR Assets. It will be important for the Enlarged Group to retain and motivate such employees if the full potential of the BKR Assets is to be realised. A failure to integrate such employees into the Enlarged Group could have a material adverse effect on the Enlarged Group's business. Furthermore, there is no assurance that the Group and, following Completion, the Enlarged Group will successfully attract new key personnel or retain existing key personnel required to continue to develop its business and to execute and implement its business strategy.

The Group currently has one production asset and the Enlarged Group's revenues will be concentrated on a limited number of producing assets

Generally, risk is reduced through diversification. Whilst the Group is planning to develop the Columbus project in the Central North Sea, and has a number of exploration interests in the Central North Sea, East Irish Sea, Ireland and Namibia, it currently only has one producing asset, Erskine in the Central North Sea in which it has a minority interest (18%). In terms of production, the Group is therefore currently heavily dependent on Erskine, and accordingly would be materially affected by a shutdown of Erskine or other material factor effecting Erskine in the event the Acquisition were not to be completed. Following the Acquisition, the Enlarged Group will be further diversified through the production from the BKR Assets but it will nevertheless remain dependent on a small number of producing assets meaning that it will be exposed to the impact of localised events or circumstances. Furthermore, the Enlarged Group's strategy will be heavily focussed on the UK and therefore it will have limited diversification in terms of the jurisdictions that it operates in.

There could be periodic restrictions to product export pipelines which reduce the capability of the BKR Assets to deliver sales volumes to market

Production of oil and gas from the assets of the Group and, following Completion, the Enlarged Group is transported through a limited number of export pipelines and, in particular, the Frigg Pipeline System and the Forties Pipeline System. Non-availability or restrictions to throughput volumes on such pipelines for any reason would delay the delivery of the Group's and, following Completion, the Enlarged Group's production to market thus delaying the receipt of revenues. In particular, the condensate export line through which Erskine liquids are transported to shore has been subject to interruptions and restrictions during 2016 and 2017, and these may recur in the future. Any such delay in revenues could have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The owner of Frigg UK gas pipeline has the right to abandon the facilities used for the transportation of natural gas from the fields

BP either alone or together with its co-venturers (the "**Shippers**") is party to transportation and processing agreements for each of the Bruce, Keith and Rhum fields with the owner of the Frigg UK gas pipeline and St Fergus onshore terminal (the "**Transporter**"). The agreements in relation to the Keith and Rhum fields include provision for the Transporter to give the Shippers notice of no less than two years of the intention to decommission the facilities or part thereof that are used for the transportation and processing of gas from the fields. Before giving such notice the Transporter is required to discuss the matter with the Shippers. Were such notice to be given and not withdrawn, the decommissioning of the facilities used to provide the service would result in the Enlarged Group having to find alternative, and potentially more expensive, means of gas transportation and, failing that, having to shut its fields in earlier than expected resulting in loss of sales revenues.

The owner of Forties Pipeline System has the right to abandon the facilities used for the transportation of liquids from the fields or to change the basis of charging for use of the facilities

BP either alone or together with its co-venturers is party to transportation and processing agreements with the Forties Pipeline System for the export of hydrocarbon liquids to the point of sale onshore. These agreements include provision for the Forties Pipeline System to give notice of two years for the abandonment of the facilities used for providing transportation and processing services. The decommissioning of the facilities used to provide the service would result in the Enlarged Group having to find alternative, and potentially more expensive, means of liquids transportation and, failing that, having to shut its fields in earlier than expected resulting in loss of sales revenues. There are also provisions which could lead to the basis for charging for use of the facilities to change from the existing tariff basis to a cost share basis. These provisions could increase the cost per barrel of transporting the Enlarged Group's share of hydrocarbon liquids to shore for sale.

The Group and, following Completion, the Enlarged Group will be subject to risks relating to its joint ventures and partners and anticipated timetables may not be achieved

Oil and gas operations globally are typically conducted through joint ventures. Certain of the Group's and, following Completion, the Enlarged Group's assets will be operated in partnership with joint venture partners and some of the Group's and, following Completion, the Enlarged Group's major projects will be operated by a partner in the relevant joint venture. The ability of the Group and, following Completion, the Enlarged Group to influence its partners will sometimes be limited, typically due to holding a relatively low percentage ownership in a non-operated development or production asset such as Erskine in the Central North Sea (Serica UK: 18%). As such, the Group's and, following Completion, the Enlarged Group's anticipated timelines in all of its current and expected operations are the Directors' estimates based on a number of variables not all of which will be under the Group's and, following Completion, the Enlarged Group's direct control. The Group and, following Completion, the Enlarged Group will be dependent upon the operators of its assets (where Serica itself is not the operator), to act in accordance with agreed plans in respect of each of the assets but the Group and, following Completion, the Enlarged Group will have no control over such persons save through contractual terms, which may be costly, time consuming or impracticable to enforce. There is a risk that the Group's and, following Completion, the Enlarged Group's partners may elect not to participate in certain activities relating to projects and which require that party's consent, including those wells which the Group and, following Completion, the Enlarged Group expects to be drilled, but has not yet committed to, as part of its drilling programme. In these circumstances it may not be possible for such activities to be undertaken by the Group and, following Completion, the Enlarged Group alone or in conjunction with other participants at the desired time or at all. Furthermore, if the timeline estimates prove to be wrong or the operators do not take the actions in relation to maintaining or developing the assets then it may lead to delays or further problems which may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business. The bankruptcy, failure or default of one or more of the Group's and, following Completion, the Enlarged Group's joint venture partners could result in the Group's and, following Completion, the Enlarged Group's share of one or more projects' liabilities and/or costs increasing unexpectedly and have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business and financial condition.

Access to infrastructure not owned by the Enlarged Group may be restricted delaying the sales of the Enlarged Group's products

The Group and, following Completion, the Enlarged Group will utilise networks of pipelines and associated infrastructure to export its products to market which are owned and operated by third parties. In the event these facilities are not available or access is restricted, this may delay sales of the Group's products and, following Completion, the Enlarged Group's products and the receipt of revenues. Restricted access to these facilities, or the non-availability of such facilities, would reduce the Group's and, following Completion, the Enlarged Group's revenues and could have a material adverse impact upon its working capital and financial position.

It may be expensive and logistically burdensome to discontinue operations should economic, physical or other conditions subsequently deteriorate

Once the Group and, following Completion, the Enlarged Group has an interest in an established oil and/or gas exploration, development and/or production operation in a particular location, it may be expensive and logistically burdensome to discontinue such an operation should economic, physical or other conditions deteriorate. This is due to, among other reasons: the significant scale of producing facilities, the nature of contractual arrangements with partners and government authorities; and significant decommissioning costs. Such costs and logistical burdens are typically greater for development and production assets due to the more established nature of the assets: the Enlarged Group will have interests in the BKR Assets, Columbus, a development project in the Central North Sea, Erskine, a producing gas condensate project also in the Central North Sea, and interests in a number of exploration assets in the Central North Sea, the East Irish Sea, offshore Ireland and offshore Namibia. Whilst the Group and, following Completion, the Enlarged Group will have limited exposure to the costs of decommissioning its Erskine field and the BKR Assets, its retained exposure in each case may cost more than projected and/or occur earlier than expected.

The Group's and, following Completion, the Enlarged Group's exploration programme may not generate commercial discoveries

The Group and, following Completion, the Enlarged Group intends to drill exploration wells when it can mitigate the cost through farm-out and, in particular, in relation to the Group's licences in the Slyne Basin, the Rockall Basin and the Luderitz Basin in Namibia. Drilling oil and gas wells is speculative, costly and may not identify sufficient quantities of commercially exploitable deposits or successfully drill, complete or develop oil or gas, in sufficient quantities to be profitable or commercially viable for the Group and, following Completion, the Enlarged Group. Moreover, the high cost of offshore development may render discoveries uneconomic other than those that are relatively large or which can be readily tied back to existing infrastructure.

There is no assurance that expenditures made on exploration licences by the Group and, following Completion, the Enlarged Group in the future will result in any new discoveries of oil or gas in commercial quantities and statistically a relatively small proportion of properties that are explored are ultimately developed into producing hydrocarbon fields. Continued expenditures on exploration activities may deplete cash resources of the Group and, following Completion, the Enlarged Group without delivering added value.

Some of the Group's and, following Completion, the Enlarged Group's activities will be capital intensive and may be subject to cost overruns and inflationary pressures

Offshore oil and gas activities, where the Group and, following Completion, the Enlarged Group will operate, are particularly capital intensive and involve a high degree of risk. The gross budgeted cost for a development or exploration well that the Group and, following Completion, the Enlarged Group may participate in can significantly exceed budgeted costs should there be lengthy weather delays, if the well encounters mechanical or sub-surface technical difficulties, or if the well finds hydrocarbons and further data gathering or side-track drilling is required. The Group and, following Completion, the Enlarged Group will seek to participate in its licences at an equity level commensurate with the Company's size and also seeks or will seek in relation to some assets and, in particular, in relation to the Group's licences in the Slyne Basin, the Rockall Basin and the Luderitz Basin in Namibia to reduce its share of costs to an acceptable level through farming-down a proportion of its equity. Nevertheless, the resulting expenditure net to the Group and, following Completion, the Enlarged Group may remain material. In addition, a well may potentially have to be abandoned because of technical and/or other difficulties and re-drilled at a later stage which can have a material adverse effect on the Group's and, following Completion, the Enlarged Group's share of the associated costs and therefore on the Group's and, following Completion, the Enlarged Group's business. Although industry costs are currently lower than in the recent past, costs may increase substantially in the event of a rise in oil and gas exploration and development activity, especially if continued low prices result in spare capacity being removed from the contracting market.

If the Enlarged Group is unable to procure the necessary finance in the form of equity and/or debt, it may be unable to commit to participate in its projects or having committed to the project, in the event that such project suffers delays or cost overruns, the Enlarged Group may be unable to meet its ongoing share of expenditure and, in either case, it could be forced to withdraw, which could have a material adverse effect on the Enlarged Group.

The Group's and, following Completion, the Enlarged Group's decommissioning liabilities may be onerous and cannot be accurately predicted

The Group and, following Completion, the Enlarged Group has through its licence interests assumed certain obligations in respect of the decommissioning of its fields and related infrastructure and is expected to assume additional decommissioning liabilities in the future. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and at the appropriate time require the Group and, following Completion, the Enlarged Group to make provisions for and/or underwrite the liabilities relating to its share of such decommissioning costs. The significant majority of decommissioning expenditure is not forecast to occur until 2023 onwards. In the case of the Erskine field, BP has agreed to retain the decommissioning liability subject to a cap. In relation to the BKR Assets, BP has agreed to retain the decommissioning liability in respect of facilities in place at Completion. In light of BP retaining the decommissioning liability in relation to the BKR Assets, Serica has agreed with BP that BP shall control the voting rights of Serica UK in relation to decommissioning matters that concern existing facilities. While Serica UK's interests in relation to decommissioning are likely to be aligned to BP's interests, BP could vote in a way which is not in the best interests of Serica UK. Serica UK will be liable for the cost of decommissioning facilities installed on the BKR Assets after the Acquisition Agreement completes.

It is difficult to forecast the costs that the Group and, following Completion, the Enlarged Group will ultimately incur in satisfying its decommissioning obligations particularly as (i) the costs of decommissioning are highly volatile, being linked to rig rates, as well as oil and gas capital expenditures generally, and (ii) regulations determining the decommissioning standards may change.

The actual costs of decommissioning and the deferred consideration payable by the Group and, following Completion, the Enlarged Group in respect of decommissioning are expected to be paid from the Enlarged Group's cash resources and cash flow generated from both the Enlarged Group's existing and future producing assets. The Group does not currently have a sinking fund to meet the costs of decommissioning its current assets. The Enlarged Group may implement a sinking fund in respect of decommissioning assets acquired in the future. The estimated timing of decommissioning is dependent upon a number of factors and a material reduction in asset profitability may bring forward such timing to a date earlier than originally envisaged.

When its decommissioning liabilities crystallise, the Enlarged Group will be jointly and severally liable for them with other former or current licence partners. In the event that other partners default on their obligations, the Enlarged Group will remain liable and its decommissioning liabilities could be magnified significantly through such default. However, in relation to the BKR Assets, this risk is largely mitigated by the partners to the BKR Assets (excluding Iranian Oil Company (UK) Limited) being required to provide security in respect of their decommissioning obligations. In the case of the Rhum field, no decommissioning security agreement has been put in place, so if IOC were to default in relation to its decommissioning obligations, the Enlarged Group's exposure to this liability would be increased. Any significant increase in the actual or estimated decommissioning costs that the Enlarged Group incurs may adversely affect its financial condition. Decommissioning tax relief in the UK is dependent on sufficient tax having been paid to shelter such expense. Consequently, the Enlarged Group may not be able to deduct such expenses, either partially or at all.

The Enlarged Group will be reliant on a functioning insurance market

Operational insurance policies are usually placed in one year contracts and the insurance market can withdraw cover for certain risks which can greatly increase the costs of risk transfer. Such increases are often driven by factors unrelated to the Group, such as well control elsewhere in the world and wind or storm damage. The Group currently maintains a programme of insurance to cover exposure up to recognised industry limits and, following Completion, the Enlarged Group will continue to maintain an appropriate insurance programme. However, in the future, there may not be sufficient cover available at economic rates in conventional markets to insure all of the Enlarged Group's potential liabilities.

Litigation against the Group and, following Completion, the Enlarged Group could materially impact the Group's and, following Completion, the Enlarged Group's business

The Group currently has no material outstanding litigation or disputes. However, there can be no guarantee that the past, current or future actions of the Group and, following Completion, the Enlarged Group will not result in litigation. In particular, investors' attention is drawn to the risk factor on page 43 entitled *"There is a dispute between BP's partner to the Rhum field and the Bruce field partners relating to Bruce field costs*". Damages claimed under such litigation may be material, and the outcome of such litigation may materially impact the Group's and, following Completion, the Enlarged Group's business, prospects, financial condition and results of operations. Defence and settlement costs can be significant, even in respect of claims that have no merit. In addition, the adverse publicity surrounding such claims may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The Group and, following Completion, the Enlarged Group will be dependent on third party contractors and providers of capital equipment

The Group has and, following Completion, the Enlarged Group will have interests in certain contracts and leases for the provision of services and capital equipment from third party providers and as the Enlarged Group develops it will have an increasing need to rely on third party contractors. Such equipment and services can be scarce and may not be readily available at the times and places required. Whilst the Group and, following Completion, the Enlarged Group and its joint venture partners allow for such events in planning their operational activities, the scarcity of such equipment and services, as well as their potentially high costs, could delay, restrict or lower the profitability and viability of the Group's and, following Completion, the Enlarged Group's projects and therefore have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business in the future. Furthermore, some of the third party providers, upon whom the Group's and, following Completion, the Enlarged Group's operations may come to depend may currently be subject to financial weakness, owing to current relatively low levels of oil and gas exploration and development activity. The bankruptcy, failure or default of one or more of the Group's and, following Completion, the Enlarged Group's suppliers could have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The Group and, following Completion, the Enlarged Group will be subject to counterparty risk

The Group and, following Completion, the Enlarged Group will become subject to agreements with a number of counterparties in relation to the sale and supply of oil and gas production volumes and related derivative contracts. The Group and, following Completion, the Enlarged Group may become therefore subject to the risk of delayed payment for delivered production volumes or counterparty default which could have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business. Whilst the Group has not experienced such events, there can be no assurance that such delays or defaults will not occur in the future.

The Group and, following Completion, the Enlarged Group cannot completely protect itself against title disputes

Although the Directors believe that the Group and, following Completion, the Enlarged Group will have good title to its oil and gas interests, it cannot control or completely protect itself against the risk of title disputes or challenges, particularly in developing jurisdictions such as Namibia.

The Group and, following Completion, the Enlarged Group will hold rights to produce, develop or explore its various oil and gas interests, but no assurance can be given that relevant governments will not revoke, or significantly alter the conditions of, the applicable exploration and development authorisations, licences, permits, approvals, consents and regulations or enforce requirements not currently enforced or that such exploration and development authorisations, licences, permits, approvals, consents and regulations will not be challenged or impugned by third parties.

The Group and, following Completion, the Enlarged Group may not be successful in obtaining new licences and assets

Future oil and gas production will to some extent depend on the Group's and, following Completion, the Enlarged Group's access to new reserves through exploration, development and acquisitions. The Group has in the past applied for, and been successful in receiving, licence awards in various jurisdictions and plans to continue to make such applications in the future. Failures in licence applications, exploration and development activities or in identifying and finalising transactions to access potential reserves would slow the Enlarged Group's oil and gas production growth and replacement of Reserves. This, in turn, could have a material adverse effect on the Enlarged Group's business.

The Group and, following Completion, the Enlarged Group may be subject to risks relating to its acquisitions and farm-outs

Part of the Group's and, following Completion, the Enlarged Group's strategy may include increasing oil and gas Reserves and/or production through strategic business acquisitions. Although the Group and, following Completion, the Enlarged Group will perform a review of the companies, businesses and properties it acquires (or intends to acquire) to standards consistent with industry practices, such reviews are inherently incomplete. It is sometimes not feasible to review in-depth every individual property involved in each acquisition. However, even where in-depth due diligence reviews are conducted, these may not reveal existing or potential problems, nor may they permit the Group and, following Completion, the Enlarged Group to become sufficiently familiar with the properties or assets to fully assess their potential or limitations and deficiencies. In addition, in order to establish a value and offer price for an acquisition the Directors will make certain technical and economic assumptions as regards the continuing performance of the asset and its associated liabilities, particularly as regards decommissioning, and in the event that those assumptions are incorrect there is a risk of overpaying for such acquisition which may have a material adverse effect on the business.

Risks commonly associated with acquisitions of companies or businesses include the difficulty of integrating the operations and personnel of the acquired business, problems with minority shareholders in acquired companies, the potential disruption of the Group's and, following Completion, the Enlarged Group's own business, the possibility that indemnification agreements with the sellers may be unenforceable or insufficient to cover potential liabilities and difficulties arising out of integration, as well as operational risks relating to the assets acquired. Furthermore, the value of any business the Group and, following Completion, the Enlarged Group may acquire or invests in may be less than the amount it pays and there can be no assurance that any acquisition will be successful and add value for the Company's Shareholders.

The Group has farmed out in the past, and the Enlarged Group intends to continue to farm-out, various commitments to third parties in circumstances where such third parties have agreed to take an assignment of an interest in one or more licences in return for paying not only the costs associated with that assigned interest but also a proportion of the costs associated with the Group and, following Completion, the Enlarged Group's retained interest in such licence. Often these costs are associated with the drilling of a well or a development and therefore can be material. There is a risk that the relevant third parties may not meet their obligations under the farm-out agreements, the underlying operations may not meet the conditions of the farm-out or the Group and, following Completion, the Enlarged Group may not be able to fulfil its associated obligations, any of which may mean that the Group and, following Completion, the Enlarged Group may have to bear the full costs associated with its retained interest. This in turn could have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business and financial condition.

The Group and, following Completion, the Enlarged Group will typically be required to consult with third party operators and other joint venture partners in relation to significant matters

The Group and, following Completion, the Enlarged Group will operate a number of their assets within various joint ventures. For those assets where the Group or following Completion the Enlarged Group is the operator and has a joint venture partner, the relevant operating agreement typically provides that the joint venture partner must be consulted or that it must provide its consent in relation to significant matters. Accordingly, while the Group and, following Completion, the Enlarged Group generally has or will have control over day-to-day management and operations of those assets, (including the BKR Assets), it may be unable to undertake certain activities because of opposition from a joint venture partner, or it may experience delays in undertaking activities due to time taken to obtain the consent of the relevant joint venture partner. Any such opposition or delay could result in losses or increased costs to the Group or following Completion the Enlarged Group.

Where the Group or following Completion the Enlarged Group is not the operator of an asset, although it may have consultant rights or the right to withhold consent in relation to significant operational matters (depending on the level of the Group's or following Completion the Enlarged Group's interest in such asset), it has limited control over day-to-day management so that mismanagement of an asset by the operator or disagreements with the operator as to the most appropriate course of action may result in significant delays, losses or increased costs to the Group or following Completion the Enlarged Group.

The terms of the relevant operating agreement generally impose standards and requirements in relation to the operator's activities. The Group and, following Completion, the Enlarged Group may transfer operatorship to a third party or acquire interests in assets operated by third party operators. Any transfer of ownership is usually also subject to the consent of the relevant government or regulatory authority, which in the UK is the OGA. Governments generally require certain criteria to be satisfied by the proposed new operator before they will approve any transfer in the role of operator. However, there can be no assurance that such operators will observe such standards or requirements and this could result in a breach of the relevant operating agreement.

There is a risk that other parties with interests in the Group's or following Completion the Enlarged Group's assets may not be able to fund or may elect not to participate in, or consent to, certain activities relating to those assets which require that party's consent (including decisions relating to drilling programmes, including the number, identity and sequencing of wells, appraisal and development decisions and decisions relating to production). In these circumstances, it may not be possible for such activities to be undertaken by the Group or following Completion the Enlarged Group alone or in conjunction with other participants at the desired time or sequence or at all.

Other participants in the Group's or following Completion the Enlarged Group's assets may default on their obligations to fund capital or other funding obligations in relation to the assets. In such circumstances, the Group or following Completion the Enlarged Group may be required under the terms of the relevant operating agreement or otherwise to contribute all or part of such funding shortfall itself.

Any disagreement, absence of consent, delay, opposition, breach of agreement or inability to undertake activities or failure to provide funding of the kind identified above could adversely affect the Group's or following Completion the Enlarged Group's business, prospects, financial condition and results of operation.

The Group and, following Completion, the Enlarged Group will be subject to licensing and other regulatory requirements

The countries in which the Group and, following Completion, the Enlarged Group will operate, being offshore the UK, Ireland and Namibia or may operate in the future, are subject to licensing and other regulations and approvals of governmental authorities, including those relating to the exploration, development, operation, production, marketing, pricing, transportation and storage of oil and gas, decommissioning, taxation, environmental, and health and safety matters.

The Group and, following Completion, the Enlarged Group will have limited control over whether or not necessary approvals or licences (or renewals thereof) are granted, the timing of obtaining (or renewing) such licences or approvals, the terms on which they are granted or the tax regime to which the Group and, following Completion, the Enlarged Group or the assets in which the Group and, following Completion, the Enlarged Group will have interests will be subject. As a result, the Group and, following Completion, the Enlarged Group may have limited control over the nature and timing of exploration and development of oil and gas fields in which the Group and, following Completion, the Enlarged Group will have or will seek interests.

There can be no assurance that the Group and, following Completion, the Enlarged Group will not in the future incur decommissioning charges since local or national governments beyond the UK may require decommissioning to be carried out in circumstances where there is no express obligation to do so, particularly in case of future licence renewals.

It is possible that in the future the Group and, following Completion, the Enlarged Group may be unable or unwilling to comply with the terms or requirements of a licence in circumstances that entitle the relevant authority to suspend or withdraw the terms of such licence. Moreover, some of the exploration and production licences which are held by the Group and, following Completion, the Enlarged Group expire or may expire before the end of what the Directors estimate to be the productive life of the licensed fields. There can be no assurance that extensions will be granted in relation to such licences. The first phase of the Group's Irish licence (P1/09) in the Rockall Basin has expired. Confirmation has been received that the first phase of the licence will be extended for an 18-month period, but as at the date of this document, the extension has not been formalised. Attention is also drawn to the risk factor entitled "*Licences P.209 and P.198 in relation to the Bruce, Keith and Rhum fields need to be renewed before Completion. If they are not renewed, Completion will* *not occur*". Any failure to receive extensions of the Group's and, following Completion, the Enlarged Group's licences or any premature termination, suspension or withdrawal of licences may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business and financial condition.

Amendments to current laws, regulations and permits, authorisations, licences, consents and approvals governing operations and activities of oil and gas companies, or more stringent implementation thereof, could result in increases of capital expenditure or production costs, installation of additional equipment, remedial actions or a reduction in levels of production from producing properties or require abandonment or delays in development of new properties, all of which could have a materially adverse effect on the Group's and, following Completion, the Enlarged Group's business, financial condition, prospects and results of operations.

Parties engaged in oil and gas operations may be required to compensate those suffering loss or damage by reason of such activities and may have civil or criminal fines or penalties imposed for violations of applicable laws or permits.

The Group and, following Completion, the Enlarged Group may be subject to the risk of exploration and appraisal periods not being extended

Whilst the Group and, following Completion, the Enlarged Group will negotiate renewals of its exploration or appraisal periods prior to their expiry, there can be no assurance that the Group and, following Completion, the Enlarged Group will be able to enter into a new phase or obtain extensions to contracts with governments, suppliers, service providers or joint venture partners on commercially reasonable terms, prior to the end of an exploration period, following the end of the period or at all.

Under certain of its licences and agreements the Group and the Enlarged Group are and will be obligated to carry out certain minimum work obligations within designated periods. In the event the Group or following Completion the Enlarged Group fails to satisfy its agreed minimum work programme commitments within the requisite time period and it is unable to secure an extension, the Group's or following Completion the Enlarged Group's interest in the relevant licence or agreement may be terminated by the government, or the Group or following Completion the Enlarged Group may be required to relinquish all or part of the contract area or pay a specified sum to the government.

It is also possible that an exploration or appraisal period set out in a relevant licence or agreement may be insufficient to perform the necessary seismic, drilling or other exploration or appraisal activities required to determine whether it is appropriate for the Group or following Completion the Enlarged Group to elect to move into the next phase of the relevant licence or agreement and commit to additional work obligations. The Group or following Completion the Enlarged Group may therefore seek to secure the necessary amendments, renewals, extensions or waivers prior to making an election to move into the next phase of exploration or appraisal, and could miss the deadline for election to the next phase, whilst discussions with the government are pending.

The necessary amendments, renewals, extensions or waivers may not be forthcoming from the relevant government on terms commercially acceptable to the Group or following Completion the Enlarged Group, giving rise to the risk that the Group's or following Completion the Enlarged Group's interest in the relevant licence or agreement may be terminated by the government or the Group or following Completion the Enlarged Group may be required to relinquish all or part of the contract area.

If the Group or following Completion the Enlarged Group is not able to obtain such amendments, renewals, extensions or waivers, this could materially and adversely affect its business, prospects, financial condition and results of operations.

The Group is, and, following Completion, the Enlarged Group will be, dependent on its reputation

To protect the Group's and, following Completion, the Enlarged Group's licences and its ability to secure new licences, it is important that the Group and, following Completion, the Enlarged Group maintains strong positive relationships with the governments of, and communities in, the countries where its business is conducted (United Kingdom, Ireland, and Namibia). The Group's and, following Completion, the Enlarged Group's relationships and reputation with other independent, national and major oil companies will also be of strategic importance particularly where such companies have interests in the Group's and, following Completion, the Enlarged Group's assets. The Group's business principles will govern how the Enlarged Group will conduct its affairs. Failure, real or perceived, to follow these principles, or any of the risk factors described in this document materialising, could harm the Enlarged Group's reputation, which could, in turn, impact the Enlarged Group's licences, financing and access to new opportunities.

The Group's, and, following Completion, the Enlarged Group's, operations may be subject to delays or disruption due to actions by environmental or other stakeholder groups

The Group's and, following Completion, the Enlarged Group's operations may in the future be subject to delays or disruption as a result of actions by environmental or other stakeholder groups.

There can be no assurance that actions by non-governmental organisations or other stakeholder or community groups in the future will not result in the revocation of the Enlarged Group's licences or agreements and/or delays or disruption in the Enlarged Group's exploration, appraisal, development or production activities, which could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

3. Financial risks relating to the Group and, following Completion, the Enlarged Group

The capital and operating expenditure of the Group and, following Completion, the Enlarged Group may be higher than anticipated

The Group and, following Completion, the Enlarged Group will have good visibility of its near term expenditure requirements, supported by detailed annual budgets. These annual budgets detail, *inter alia*, the necessary equipment, personnel and time lines for such programmes, and estimates for the year's expenditure based on the current market rates plus appropriate contingencies. In addition, regular meetings of management support forecast estimates for the work programme and expenditure in the next period.

However, in the longer term, annual budgets may turn out to be higher than currently planned by Serica (for example, for reasons of oil industry-wide cost inflation, operational problems, project delays or redesign, new technology, acceleration of work programmes in particular decommissioning, and/or best practice for seismic, drilling, development and/or decommissioning and other operations) and the Group and, following Completion, the Enlarged Group may need to seek additional funds at that time to cover increased costs or the fact that the Group and, following Completion, the Enlarged Group may no longer be tax optimised as planned due to unforeseen or earlier than expected costs, which it may not be able to secure on reasonable commercial terms or at all or it may need to divert funds from other projects to satisfy the increased capital expenditure requirements. If this happens, it may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business and financial condition in the longer term.

The Group and, following Completion, the Enlarged Group will be subject to exchange rate risk

The Enlarged Group will operate in the United Kingdom, Ireland, and Namibia. Changes in currency values and exchange controls could have a material adverse effect on the Group and, following Completion, the Enlarged Group's operational results and financial position.

The ability for the Group and, following Completion, the Enlarged Group to utilise future debt facilities will be subject to certain conditions

The Group currently has no bank debt facilities. It has, however, entered into the Prepayment Facility pursuant to the Acquisition under which BP has provided to the Enlarged Group an advanced gas sales facility of up to £16 million. It is also possible that, following Completion, the Enlarged Group will enter into other debt facilities. The ability to utilise and/or draw down on these facilities is likely to be subject to customary conditions, such as compliance with financial and operational ratios and representations. In the event that the Enlarged Group is unable to satisfy these conditions or representations Serica will be unable to draw down under the facilities and/or may be required to repay all or a proportion of the amount already drawn down under them.

In the event that the Enlarged Group is required to repay any such facilities prior to the end of their term due to default or other circumstances and/or is unable to extend or enter into new such facilities, it could have a material adverse effect on the Enlarged Group's business, financial condition and results of operations.

The Group and, following Completion, the Enlarged Group may be unable to optimise its tax position

The Group seeks to and, following Completion, the Enlarged Group will seek to optimise its tax position within the relevant legislation. In particular, it will seek to utilise its existing tax losses to reduce tax liabilities that would otherwise fall due on its UK ring-fenced profits. Should, for any reason, it not be allowed to do so by the relevant tax authorities, then the Enlarged Group's projected tax payments may increase, which would adversely impact the financial position of Enlarged Group.

The Group and, following Completion, the Enlarged Group could be subject to bank default

Credit market events in the last few years have demonstrated the possibility of banks, previously thought to be secure, defaulting on their deposits. A good rating from a reputable rating agency does not provide protection against default risk and, as a corporate depositor, Serica may fall outside any deposit protection schemes. The Group holds material cash balances at both Barclays Bank and Lloyds Bank. The Directors have no specific concerns as to the viability of any of these banks and consider the prospect of default to be highly improbable in the foreseeable future. However, in the unlikely event of such an event, if one or more of such banks defaults on its deposits it would have a material adverse effect on the Group's and, following Completion, the Enlarged Group's ability to fund its commitments. In such an economic environment the Group and, following Completion, the Enlarged Group would be unlikely to be able to sell assets at reasonable values or raise equity finance and consequently might be unable to continue its business.

The Group and, following Completion, the Enlarged Group is subject to changes in credit market and equity market conditions

Serica will have sufficient financial resources to meet its obligations arising within the period of the working capital statement contained in this document. However, the nature of its business is capital intensive and in the longer term, its projects may be subject to delays or cost overruns and its sources of revenue may be subject to interruption. Any of these risks may create circumstances where the Enlarged Group requires additional financing from credit or equity markets in the longer term and the availability of such financing is subject to market conditions. In the event that such financing were not available at that time, it could have a material adverse effect on the Enlarged Group's financial condition.

The Enlarged Group may have an additional need for working capital

Serica UK will operate the Rhum field with IOC as its partner. Due to heightened concerns about US sanctions many banks do not wish to provide banking services related to payments to and from Iranian companies which may delay the receipt of joint venture funds receivable from IOC. Such delays could cause shortfalls in funds for Rhum field operations. Were such shortfalls to occur, Serica UK may have an additional need for working capital to cover such shortfalls from time to time. Were such shortfall to occur, Serica UK would expect to be able to fund them from its own internal resources.

The Enlarged Group may have the need for additional capital in the longer term

The Enlarged Group may need additional funds in the longer term, outside the period of the working capital statement contained in this document, in order to further fund its exploration and development programmes. Additional equity financing may be dilutive to holders of the Company's then existing Ordinary Shares and could contain rights and preferences superior to those of the Ordinary Shares. Debt financing may involve restrictions on the Enlarged Group's financing and operating activities. In either case, additional financing may not be available to the Enlarged Group on acceptable terms. If the Enlarged Group is unable to raise additional funds as needed, the scope of its operations may be reduced and, as a result, the Enlarged Group may be unable to fulfil its long-term growth programme, or meet its contractual obligations under its contracts which may ultimately be withdrawn or terminated for non-compliance.

The Group and, following Completion, the Enlarged Group will be subject to health, safety, environment and security risks

The Group and, following Completion, the Enlarged Group will be subject to Health, Safety, Environment and Security ("**HSES**") risks. The Group's and, following Completion, the Enlarged Group's HSES risks will include major process safety incidents; failure to comply with approved legislation or policies; effects of natural disasters and pandemics; exposure to general operational hazards; personal health and safety; strikes; non-governmental organisation activity; terrorism and crime. The consequences of such risks materialising can be injuries, loss of life, environmental harm, disruption to business activities and financial loss. Depending on cause and severity, the materialisation of such risks may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

In addition, failure by the Group and, following Completion, the Enlarged Group to comply with applicable legal requirements or recognised international standards may give rise to significant liabilities. HSES laws and regulations have become more complex and stringent and/or the subject of increasingly strict interpretation or enforcement, particularly since the Deepwater Horizon incident in 2010, and may become more so over time. There may also be unforeseen environmental liabilities resulting from oil and gas activities which may be costly to remedy. In particular, the acceptable level of pollution and potential clean-up costs and obligations and liability for toxic or hazardous substances for which the Group and, following Completion, the Enlarged Group may become liable as a result of its activities may be impossible to assess against the current legal framework and current enforcement practices of the various jurisdictions. The terms of licences may include more stringent HSES requirements. The obtaining of exploration, development or production licences and permits may become more difficult and/or be the subject of delay by reason of governmental, regional or local environmental consultation, approvals or other considerations or requirements. These factors may lead to delayed or reduced exploration, development or production activity as well as to increased costs and may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The Group is and, following Completion, the Enlarged Group will be subject to cyber risks

The Group is and, following Completion, the Enlarged Group will be at risk of financial loss, reputational damage and general disruption from a failure of its IT systems or an attack for the purposes of espionage, extortion, terrorism or to cause embarrassment. Any failure of, or attack against, Serica's IT systems may be difficult to prevent or detect, and Serica's internal policies to mitigate these risks may be inadequate or ineffective. Serica may not be able to recover any losses that may arise from a failure or attack.

4. Market risks relating to the Group and, following Completion, the Enlarged Group and the oil and gas industry

Oil and gas prices fluctuate

The Group's and, following Completion, the Enlarged Group's future operations and financial condition, the value of its oil and gas reserves and its level of spending for oil and gas exploration and development are sensitive to prevailing prices of oil and gas. Historically, prices of oil and gas have been subject to wide fluctuations for many reasons, including:

- global and regional supply and demand, and expectations regarding future supply and demand, for oil and gas;
- availability of pipelines, tankers and other transportation and processing facilities;
- proximity to, and the capacity and cost of, transportation;
- price and availability of new technologies and alternative sources of energy;
- global and regional economic conditions;
- political, economic and military developments in oil and gas producing regions;
- weather conditions and natural disasters;
- speculative activities and trends in the financial community;
- the willingness and ability of members of OPEC, and other oil producing nations, to set and maintain specified levels of production and prices; and
- governmental regulations and actions, including the imposition of export restrictions and taxes.

The current market price of hydrocarbon products is volatile and has had periods of weakness relative to historical medium term prices and could reach a level at or below the operating costs of the Group and, following Completion, the Enlarged Group for an extended period. This not only reduces cash flow needed to meet the Group's and, following Completion, the Enlarged Group's commitments in the short term but also reduces the Group's and, following Completion, the Enlarged Group's debt capacity and the economic value of the Group's and, following Completion, the Enlarged Group's projects which may be significantly reduced or rendered uneconomic, which in turn may lead to early abandonment. Early abandonment crystallises decommissioning liabilities earlier and may negatively impact the Group's and, following Completion, the Enlarged Group's cash flow.

It is impossible to predict future oil and gas price movements so Serica UK has hedged a proportion of anticipated gas production for 2018 through to the first half of 2020. There is a particular risk when committing to long-term development contracts or acquisitions based on assumed future hydrocarbon prices.

These hedging arrangements may reduce, but will not eliminate, the potential effects of changing commodity prices on the Company's cash flow from operations for the periods covered by these arrangements. In addition, these arrangements expose the Company to risks of financial loss when a counterparty is unable to satisfy its obligations.

The Group and, following Completion, the Enlarged Group can give no assurance that future prices for oil and gas will be sufficient to generate an economic return nor that hedging contracts can be arranged in the future with similar floor prices as currently in force. Any further decline in such prices could result in reduced cash flows from the Group's and, following Completion, the Enlarged Group's assets and a reduction in the valuation of the Group's and, following Completion, the Enlarged Group's assets, which in turn may result in a reduction in the debt available to the Group and, following Completion, the Enlarged Group. This would have a material adverse effect on the Group's and, following Completion, the Enlarged Group's financial condition, business, prospects and results of operations.

The estimation of Reserves, resources and production profiles is not exact

The estimation of oil and gas Reserves, and their anticipated production profiles, involves subjective judgements and determinations based on a number of variable factors and assumptions, such as expected reservoir characteristics based on geological, geophysical and engineering assessments, future production rates based on historical performance and expected future operating investment activities, future oil and natural gas prices and quality differentials, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. They are not exact determinations and are inherently uncertain. In addition, these judgements may change based on new information from production or drilling activities or changes in economic factors, as well as from developments such as acquisitions and disposals, new discoveries and extensions of existing fields and the application of improved recovery techniques. Published reserve estimates are also subject to correction for errors in the application of published rules and guidance. It should be noted that the effective date of the estimations of key Reserves and resources in the BKR Assets CPR and Serica CPR is 1 June 2017 and 30 June 2017 respectively, and not the date of this document.

The Reserves, resources and production profile data contained in this document are estimates only and should not be construed as representing exact quantities. They are based on production data, prices, costs, ownership, geophysical, geological and engineering data, and other information assembled by the Company. The estimates may prove to be incorrect and potential investors should not place undue reliance on the forward-looking statements contained in this document concerning the Group's and, following Completion, the Enlarged Group's reserves and resources or production levels.

If the assumptions upon which the estimates of the Group's and, following Completion, the Enlarged Group's Reserves, resources or production profiles have been based prove to be incorrect, the Group and, following Completion, the Enlarged Group may be unable to recover and produce the estimated levels or quality of oil and gas set out in this document and this may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

Contingent and prospective resources are unlikely to be commercially productive in the short or medium term

This document contains estimations of contingent and prospective resources attributable to the Group and, following Completion, the Enlarged Group. Uncertainties exist with respect to the estimation of contingent and prospective resources in addition to those that apply to Reserves. Contingent resources are resources estimated, at a given date, to be potentially recoverable from known accumulations but are not yet considered mature enough for commercial development due to one or more contingencies. Contingent resources may include, for example, projects for which there are no visible markets, or where commercial recovery is dependent upon technology under development, the availability of export routes or where evaluation is insufficient to clearly assess commerciality. Prospective resources are resources estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Development of contingent and prospective resources, if undertaken, may involve considerable expense and may not result in the discovery of hydrocarbons in commercially viable quantities. Volumes and values associated with contingent and prospective resources should be considered highly speculative and there can be no guarantee that the Group and, following Completion, the Enlarged Group will be able to develop these resources commercially.

The Group is and, following Completion, the Enlarged Group will be subject to significant competition

The Group operates in and the Enlarged Group will operate in a very challenging business environment and competition for access to exploration and production licences and acreage, gas markets, oil services and rigs, technology and processes, and human resources is intense. Competitors include companies with, in many cases, greater financial resources, local contacts, staff and facilities than those of the Group and, following Completion, the Enlarged Group. These companies have strong market power as a result of several factors, including the diversification and reduction of risks (including geological, price and currency risks); increased financial strength facilitating major capital expenditure; greater integration and the exploitation of economies of scale in technology and organisation; strong technical experience; increased infrastructure and reserves; and strong brand recognition. Competition for exploration and production licences as well as other regional investment or acquisition opportunities may increase in the future and the Group and, following Completion, the Enlarged Group may be unable to acquire attractive, suitable assets or prospects on terms that it considers acceptable. This may lead to increased costs in the carrying on of the Group's and, following Completion, the Enlarged Group's activities and reduced available growth opportunities. Any failure by the Group and, following Completion, the Enlarged Group to compete effectively could have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business.

The Group is and, following Completion, the Enlarged Group will be subject to fiscal and other risks derived from government involvement in the oil and gas industry

The governments of countries in which the Group currently operates or in which the Enlarged Group may operate have exercised and continue to exercise significant influence over many aspects of their respective economies, including the oil and gas industry. Any government action concerning the economy, including the oil and gas industry, such as a change in oil or gas pricing policy (including royalties), exploration and development policy, or taxation rules or practice (particularly the UK's decommissioning tax relief or renegotiation or nullification of existing concession contracts), could have a material effect on the Group and, following Completion, the Enlarged Group. Furthermore, there can be no assurance that these governments will not postpone or review projects or will not make any changes to laws, rules, regulations or policies, in each case, which could materially and adversely affect the Group's and, following Completion, the Enlarged Group's financial position, results of operations or prospects.

Whilst Namibia is a relatively stable country, the Enlarged Group will be subject to certain local risks from operating in that jurisdiction

The Group has an 85% interest in a Petroleum Agreement with National Petroleum Corporation of Namibia (Pty) Limited and Indigenous Energy (Pty) Limited covering four blocks in the Luderitz Basin in Namibia. Whilst Namibia has been politically stable since gaining independence from South Africa in 1990, it is nevertheless a developing country which may be subject to political, economic, legal, regulatory and social uncertainties. The Enlarged Group will depend on the granting of permits and consents from authorities in Namibia, and it may experience substantial delays or increased costs in obtaining such permits. It may also be impacted by changes in government policy. Uncertainties in the interpretation and application of laws and regulations (including tax regulations) in Namibia could have an adverse effect on the Enlarged Group's business in Namibia. The success of the Enlarged Group's business in Namibia depends on its Petroleum Agreement with National Petroleum Corporation of Namibia (Pty) Limited and Indigenous Energy (Pty) Limited. In the event that the Petroleum Agreement was challenged, this would have an adverse effect on the Enlarged Group's operations in Namibia. Namibia ranks 53rd out of 176 in the Corruptions Perceptions Index 2016 making it one of the best performing countries in Africa.

The Group and, following Completion, the Enlarged Group faces risks relating to the UK's continued membership of the European Union

A referendum was held in the UK on 23 June 2016 on whether the UK will remain a member of the European Union, the result of which was a vote to leave. The Group and, following Completion, the Enlarged Group faces risks associated with both the potential uncertainty during the period following the referendum and also the consequences that may flow from exiting the European Union. Credit rating agencies have downgraded the UK sovereign credit rating, with S&P downgrading the UK to

AA from AAA with negative outlook, given the increase in probability of an economic slowdown as a result of the decision to leave. For example, because a significant proportion of UK law and regulation is based on European Union legislation and directives, leaving the European Union could materially change the legal and regulatory framework that would be applicable to the Group's and, following Completion, the Enlarged Group's operations in the future. This could increase operating costs as well as restrict the movement of capital and mobility of personnel for the Group and, following Completion, the Enlarged Group and have a material effect on the Group's and, following Completion, the Enlarged Group's business, financial condition, results of operations and prospects.

The Group's and, following Completion, the Enlarged Group's business, results of operations and financial condition could be adversely affected by the future independence of Scotland

Certain of the Group's and, following Completion, the Enlarged Group's operations, principally those in the North Sea, will involve third party contractors and providers of capital equipment based in Scotland. In addition, all of the Enlarged Group's production in the near term is likely to be generated from Scottish waters. The uncertainty created by any future vote on independence in Scotland, for example resulting from the decision in the UK referendum on 23 June 2016 to leave the European Union, may have a negative impact on the Group's and, following Completion, the Enlarged Group's ability to obtain services from Scottish companies and/or continue to deliver hydrocarbons into Scotland, at all, at economic rates and/or at levels similar to current rates. There can be no assurances that, even if Scotland were to apply for European Union membership following an affirmative vote in favour of Scottish independence, that it would be able to join as an independent member. The UK government has stated that there is unwillingness to maintain a currency union with an independent Scotland, so that Scotland would no longer be entitled to use pounds sterling as its official currency and there is uncertainty as to whether Scotland would be able to or willing to adopt the Euro.

In the event of Scottish independence, there is a risk that the Scottish fiscal regime would accrue the majority of the Group's and, following Completion, the Enlarged Group's tax losses as Scottish and restrict the Group and, following Completion, the Enlarged Group from offsetting any future profits generated from operations in England. In the absence of such tax losses, any profits generated from operations in England could be materially adversely affected, and it could make utilisation of past tax losses more difficult which may reduce the Group's and, following Completion, the Enlarged Group's competitiveness when bidding for assets.

In the event of Scottish independence, the above factors could have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business, results of operations and financial condition.

Conservation measures and technological advances could reduce demand for oil and natural gas

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy-generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas services and products may have a material adverse effect on the Group's and, following Completion, the Enlarged Group's business, financial condition and results of operations.

5. Risk factors relating to the Ordinary Shares

There is no public market for the Ordinary Shares in the United States or elsewhere outside the United Kingdom. The Ordinary Shares have not been registered under the US Exchange Act and are not listed on any US securities exchange or interdealer quotation system. The Company has no intention to file any such registration statement or list the Ordinary Shares on any securities exchange or interdealer quotation system (other than AIM). As a consequence, an active trading market is not expected to develop for the Ordinary Shares outside the United Kingdom and investors outside the United Kingdom may not be able to sell the Ordinary Shares or achieve an acceptable price. As a prospective purchaser, you should be aware that you may be required to bear the financial risks of this investment for an indefinite period of time.

Pre-emption rights may not be available to Overseas Shareholders of Ordinary Shares

In the case of certain increases in the Company's issued share capital, holders of Ordinary Shares have the benefit of statutory pre-emption rights to subscribe for such shares, unless Shareholders waive such rights by a resolution passed at a Shareholders' meeting, or in certain other circumstances as stated in the Articles. United States and other overseas holders of shares are very likely to be excluded from exercising any such pre-emption rights they may have, unless a registration statement under the US Securities Act is effective with respect to those rights, or an exemption from the registration requirements under the US Securities Act is available. The Company is unlikely to file any such registration statement due to cost and other considerations, and the Company cannot assure prospective investors that any exemption from those registration requirements would be available to enable United States or other overseas shareholders to exercise such pre-emption rights or, if available, that the Company will utilise any such exemption.

Shareholders may be exposed to fluctuations in currency exchange rates

The Ordinary Shares are priced in pounds sterling, and will be quoted and traded in pounds sterling. Accordingly, Shareholders resident in non-UK jurisdictions are subject to risks arising from adverse movements in the value of their local currencies against pounds sterling, which may reduce the value of the Ordinary Shares. This is particularly relevant given the uncertainty around the UK's exit from the European Union.

The ability of Overseas Shareholders to bring actions or enforce judgements against the Company or the Directors may be limited

The ability of an Overseas Shareholder to bring an action against the Company may be limited under law. The Company is a public limited company incorporated in England and Wales. The rights of holders of Ordinary Shares are governed by English law and by the Company's Articles. These rights differ from the rights of shareholders in typical US corporations and some other non-UK corporations. An Overseas Shareholder may not be able to enforce a judgement against the Company, the Enlarged Group or some or all of the Directors and executive officers. Consequently, it may not be possible for an Overseas Shareholder to effect service of process upon the Company or the Directors and executive officers within the Overseas Shareholder's country of residence or to enforce against the Company or the Directors and executive officers within the Overseas Shareholder's country of residence or to enforce against the Company or the Directors and executive officers' judgements of courts of securities laws. There can be no assurance that an Overseas Shareholder will be able to enforce any judgements in civil and commercial matters or any judgements under the securities laws of countries other than the UK against the Company or the Directors or executive officers who are residents of the UK or countries other than those in which judgement is made. In addition, English or other courts may not impose civil liability on the Company or the Directors or executive officers in any original action based solely on foreign securities laws brought against the Company or the Directors in a court of competent jurisdiction in England or other countries.

The Ordinary Shares may not be suitable as an investment

The Ordinary Shares may not be a suitable investment for all the recipients of this document. Before making a final decision, investors are advised to consult an independent investment adviser authorised under the FSMA who specialises in advising on the acquisition of shares and other securities. The value of the Ordinary Shares and any income received from them can go down as well as up and investors may get back less than their original investment.

The Company's securities are traded on AIM rather than the Official List

The Ordinary Shares will be traded on AIM rather than the Official List. An investment in shares traded on AIM may carry a higher risk than those listed on the Official List. The market price of the Ordinary Shares may be subject to wide fluctuations in response to many factors, including variations in the operating results of the Group and, following Completion, the Enlarged Group, divergence in financial results from analysts' expectations, changes in estimates by stock market analysts, general economic conditions, overall market or sector sentiment, legislative changes in the Group's and, following Completion, the Enlarged Group's sector and other events and factors outside of the Group's and, following Completion, the Enlarged Group's control. Stock markets have from time to time experienced severe price and volume fluctuations, a recurrence of which could adversely affect the market price for the Ordinary Shares. Prospective investors should be aware that the value of the Ordinary Shares may be volatile and could go down as well as up, and investors may therefore not recover their original investment especially as the market in the Ordinary Shares may have limited liquidity. Admission to AIM should not be taken as implying that there will be a liquid market for the Ordinary Shares.

The Company's share price fluctuates

The market price of the Ordinary Shares could be subject to significant fluctuations due to a change in sentiment in the market regarding the Ordinary Shares (or securities similar to them). Such risks depend on the market's perception of the likelihood of success of the Acquisition and/or may occur in response to various facts and events, including any variations in the Group's and, following Completion, the Enlarged Group's operating results, business developments and/or its competitors. Stock markets have, from time to time, experienced significant price and volume fluctuations that have affected the market prices for securities and which may be unrelated to the Company's operating performance or prospects. Furthermore, the Company's operating results and prospects from time to time may be below the expectations of market analysts and investors. Any of these events could result in a decline in the market price of the Ordinary Shares and investors may, therefore, not recover their original investment.

Any sale of Ordinary Shares could have an adverse effect on the market price of the Ordinary Shares. Furthermore, it is possible that the Company may decide to offer additional shares in the future. An additional offering could also have an adverse effect on the market price of the Ordinary Shares.

PART V – COMPETENT PERSON'S REPORT ON THE BKR ASSETS

BP Exploration and Production

Estimated

Future Reserves, Income and 2C Contingent Resources

Attributable to Certain Net Interests in the

Bruce, Keith and Rhum Fields

North Sea

SPE-PRMS Escalated Parameters

As of

June 1, 2017

Guale Ramirez, P.E.
TBPE License No. 48318
Executive Vice President

Mario A. Ballesteros, P.E.
TBPE License No. 107132
Managing Senior Vice President

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

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November 17, 2017

BP Exploration and Production
Chertsey Road
Sunbury-on-Thames
Middlesex, TW16 7LN
United Kingdom

Serica Energy plc
52 George Street
London, W1U 7EA
United Kingdom

Peel Hunt LLP
120 London Wall
London, EC2Y 5ET
United Kingdom

Gentlemen:

1.0 Executive Summary

At the request of BP Exploration and Production (BP), Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved, proved plus probable (2P) and proved plus probable plus possible (3P) reserves, and future production and income, and 2C contingent resources attributable to certain properties/assets of BP in the North Sea region as of June 1, 2017. Three fields, namely the Bruce, Keith and Rhum fields, were included in this evaluation, which are located in offshore waters of the United Kingdom.

We have been informed by Serica Energy plc (Serica Energy) that it proposes through its wholly-owned subsidiary Serica Energy (UK) Limited to acquire the Bruce, Keith and Rhum fields (BKR Assets). We have also been informed that the proposed acquisition will constitute a reverse takeover of Serica Energy under the AIM Rules for Companies (AIM Rules) and will be conditional, inter alia, upon the approval of Serica Energy's shareholders. As part of the process, we have been informed by Serica Energy that Serica Energy, as enlarged by the acquisition of the BKR Assets, will need to seek re-admission on the AIM Market of the London Stock Exchange plc. We understand that this Competent Person's Report (CPR) will be included in the new Admission Document in connection with the re-admission to AIM.

This CPR has been prepared in accordance with the AIM Rules, specifically the "Note for Mining, Oil and Gas Companies" dated June 2009 and the content requirements at Appendix 2 and the summaries set out in Appendices 1 and 3. [1]

[1] Note: responsibility statement to be included at the back of the Admission Document itself.

SUITE 600, 1015 4TH STREET, S.W. CALGARY, ALBERTA T2R 1J4 TEL (403) 262-2799 FAX (403) 262-2790
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The reserves and contingent resources volumes included herein were estimated based on the definitions and disclosure guidelines contained in the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) Petroleum Resources Management System (SPE-PRMS) based on escalated price and cost parameters (SPE-PRMS forecast case) provided by BP.

In this report, the reserve volumes were estimated based on escalated cost and price parameters as provided by BP which may reasonably exist during the life of the properties. We refer to this case, using escalated cost and price parameters, as the SPE-PRMS Forecast Case. Such forecasts were based on projected escalations or other forward-looking changes to current prices and/or costs as noted. These parameters were used to estimate the economic limit and thus the CoP (cessation of production) dates for each field.

At the request of BP, we include Proved (1P), aggregated BP's proved plus probable (2P) and aggregated proved plus probable plus possible (3P) reserves for presentation purposes as shown below. Proved, probable and possible reserves are characterized as having varying degrees of risk associated with them and are not comparable. We emphasize that the 2P and 3P reserves presented below represent aggregations of different reserve categories that are characterized by significantly different levels of uncertainty and have not been adjusted to reflect the varying levels of associated risk. As requested by BP, we evaluated the 2C Contingent Resources but not the Prospective Resources pertaining to the subject properties.

BP has informed us that all decommissioning costs related to the subject properties will remain the responsibility of BP after Serica acquires the interests assessed in this report. The results of our economic appraisal are presented herein both with the inclusion of decommissioning costs and without. The economic results are shown on an after tax basis. At your request, we have used a 40% flat corporate tax rate and no provision was made for Petroleum Revenue Taxes (PRT). Although in the future PRT will likely be paid by the working interest owners of these properties, it was beyond the scope of work of this report to determine the amounts of such taxes and the proportionate liability to each working interest owner. The results of our third party study, completed on August 31, 2017, are presented below.

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce, Keith and Rhum** Fields
BP Exploration and Production
As of June 1, 2017

	Gross			**Net Attributable**			**Operator**
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	8,214	11,979	12,852	3,394	4,994	5,430	BP
Gas reserves per asset							
From production to planned for development - MMcf	365,943	562,324	647,179	171,008	264,258	306,686	BP
Income Data (M$)							
Future Gross Revenue				$966,197	$1,503,509	$1,739,202	BP
Deductions				$885,986	$1,108,472	$1,136,631	BP
Undiscounted Net Present Value (NPV)				$80,211	$395,037	$602,571	BP
Discounted NPV10 Post Tax				$137,867	$259,472	$334,258	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce** Field
BP Exploration and Production
As of June 1, 2017

	Gross			**Net Attributable**			**Operator**
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	4,339	6,334	6,334	1,562	2,280	2,280	BP
Gas reserves per asset							
From production to planned for development - MMcf	83,178	118,400	118,400	29,944	42,624	42,624	BP
Income Data (M$)							
Future Gross Revenue				$227,183	$328,269	$328,269	BP
Deductions				$389,673	$411,362	$404,344	BP
Undiscounted Net Present Value (NPV)				($162,490)	($83,093)	($76,075)	BP
Discounted NPV10 Post Tax				$880	$35,891	$38,627	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Rhum** Field
BP Exploration and Production
As of June 1, 2017

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	3,181	4,927	5,800	1,591	2,464	2,900	BP
Gas reserves per asset							
From production to planned for development - MMcf	280,663	441,763	526,618	140,332	220,881	263,309	BP
Income Data (M$)							
Future Gross Revenue				$723,608	$1,159,272	$1,394,966	BP
Deductions				$457,822	$658,157	$693,334	BP
Undiscounted Net Present Value (NPV)				$265,786	$501,115	$701,632	BP
Discounted NPV10 Post Tax				$140,792	$227,356	$299,406	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Keith** Field
BP Exploration and Production
As of June 1, 2017

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	694	717	717	242	250	250	BP
Gas reserves per asset							
From production to planned for development - MMcf	2,101	2,162	2,162	732	753	753	BP
Income Data (M$)							
Future Gross Revenue				$15,406	$15,967	$15,967	BP
Deductions				$38,491	$38,953	$38,953	BP
Undiscounted Net Present Value (NPV)				($23,085)	($22,986)	($22,986)	BP
Discounted NPV10 Post Tax				($3,805)	($3,775)	($3,775)	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce, Keith and Rhum** Fields
BP Exploration and Production (No Decommissioning Costs)
As of June 1, 2017

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	8,214	11,979	12,852	3,394	4,994	5,430	BP
Gas reserves per asset							
From production to planned for development - MMcf	365,943	562,324	647,179	171,008	264,258	306,686	BP
Income Data (M$)							
Future Gross Revenue				$966,197	$1,503,509	$1,739,202	BP
Deductions				$488,707	$711,193	$739,352	BP
Undiscounted Net Present Value (NPV)				$477,490	$792,316	$999,850	BP
Discounted NPV10 Post Tax				$217,815	$339,420	$414,205	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS
Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Bruce** Field
BP Exploration and Production (No Decommissioning Costs)
As of June 1, 2017

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	4,339	6,334	6,334	1,562	2,280	2,280	BP
Gas reserves per asset							
From production to planned for development - MMcf	83,178	118,400	118,400	29,944	42,624	42,624	BP
Income Data (M$)							
Future Gross Revenue				$227,183	$328,269	$328,269	BP
Deductions				$104,405	$126,094	$119,076	BP
Undiscounted Net Present Value (NPV)				$122,778	$202,175	$209,193	BP
Discounted NPV10 Post Tax				$56,548	$91,559	$94,295	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS

Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Rhum** Field
BP Exploration and Production (No Decommissioning Costs)
As of June 1, 2017

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	3,181	4,927	5,800	1,591	2,464	2,900	BP
Gas reserves per asset							
From production to planned for development - MMcf	280,663	441,763	526,618	140,332	220,881	263,309	BP
Income Data (M$)							
Future Gross Revenue				$723,608	$1,159,272	$1,394,966	BP
Deductions				$379,080	$579,415	$614,592	BP
Undiscounted Net Present Value (NPV)				$344,528	$579,857	$780,374	BP
Discounted NPV10 Post Tax				$156,348	$242,912	$314,962	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

PRMS ESCALATED PARAMETERS

Estimated Gross and Net Attributable Reserves and Income Data
Certain Interests in the **Keith** Field
BP Exploration and Production (No Decommissioning Costs)
As of June 1, 2017

	Gross			Net Attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil & Liquids reserves per asset							
From production to planned for development - Mbbls	694	717	717	242	250	250	BP
Gas reserves per asset							
From production to planned for development - MMcf	2,101	2,162	2,162	732	753	753	BP
Income Data (M$)							
Future Gross Revenue				$15,406	$15,967	$15,967	BP
Deductions				$5,223	$5,684	$5,684	BP
Undiscounted Net Present Value (NPV)				$10,183	$10,283	$10,283	BP
Discounted NPV10 Post Tax				$4,919	$4,949	$4,949	BP

Note: "Operator" is name of the company that operates the asset

Note: "Gross" are 100% of the reserves and/or resources attributable to the license whist "Net Attributable" are those attributable to the AIM company

The Discounted Net Present Value (NPV) in the above table represents the post-tax cashflow of the Future Net Income (FNI) of the subject properties.

The estimated 2C contingent resources are summarized below. BP estimates the risk of development for these contingent resources to be 50%.

BRUCE FIELD	GROSS		NET (BP 36% WI)	
	2C		2C	
	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP	7	210	3	76

KEITH FIELD	GROSS		NET (BP 34.83% WI)	
	2C		2C	
	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP	6	18	2	6

RHUM FIELD	GROSS		NET (BP 50% WI)	
	2C		2C	
	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP	436	77,438	218	38,719

Liquid hydrocarbons are expressed in thousands of standard 42 U.S. gallon barrels (MBarrels). All gas volumes are reported on an "as sold" basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure base of the areas in which the gas reserves are located. Those gas volumes that are consumed as fuel in operations are also reported separately herein. The remaining reserves and contingent resources are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 5,800 cubic feet of natural gas per one barrel of oil equivalent which does include fuel gas. MMBOE means million barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars (M$).

The estimates provided above are consistent with BP's field development plans, which were provided to us by BP with its assurance that such plans will be implemented.

Ryder Scott served as independent evaluator in the conduct and analyses described and in the determination of professional opinions expressed herein. Ryder Scott and the management and staff of Ryder Scott are independent of BP and of Serica Energy and have no interest in any assets or share capital of BP or Serica Energy or in the promotion of BP or Serica Energy. Neither Ryder Scott nor its staff will receive any pecuniary or other benefits in connection with this assignment other than a normal fixed consultancy fee and no part of the fee is contingent on the conclusions reached. Ryder Scott is professionally qualified and a member in good standing of an appropriate recognized professional association under the AIM Rules with at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets.

Ryder Scott confirms that, to the best of its knowledge, there has been no material change in the information contained in this CPR since June 1, 2017 being the date to which we have estimated the reserves and resources contained in this report.

This report was prepared for BP Exploration and Production, Serica Energy and Peel Hunt LLP (in its capacity as nominated adviser to Serica Energy) and should not be used for purposes other than those for which it is intended without our prior written consent. The data and work papers used in the preparation of this report are available for examination in our offices by parties with written authorization from BP Exploration and Production. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Guale Ramirez, P.E.
TBPE License No. 48318
Executive Vice President

Mario A. Ballesteros, P.E.
TBPE License No. 107132
Managing Senior Vice President

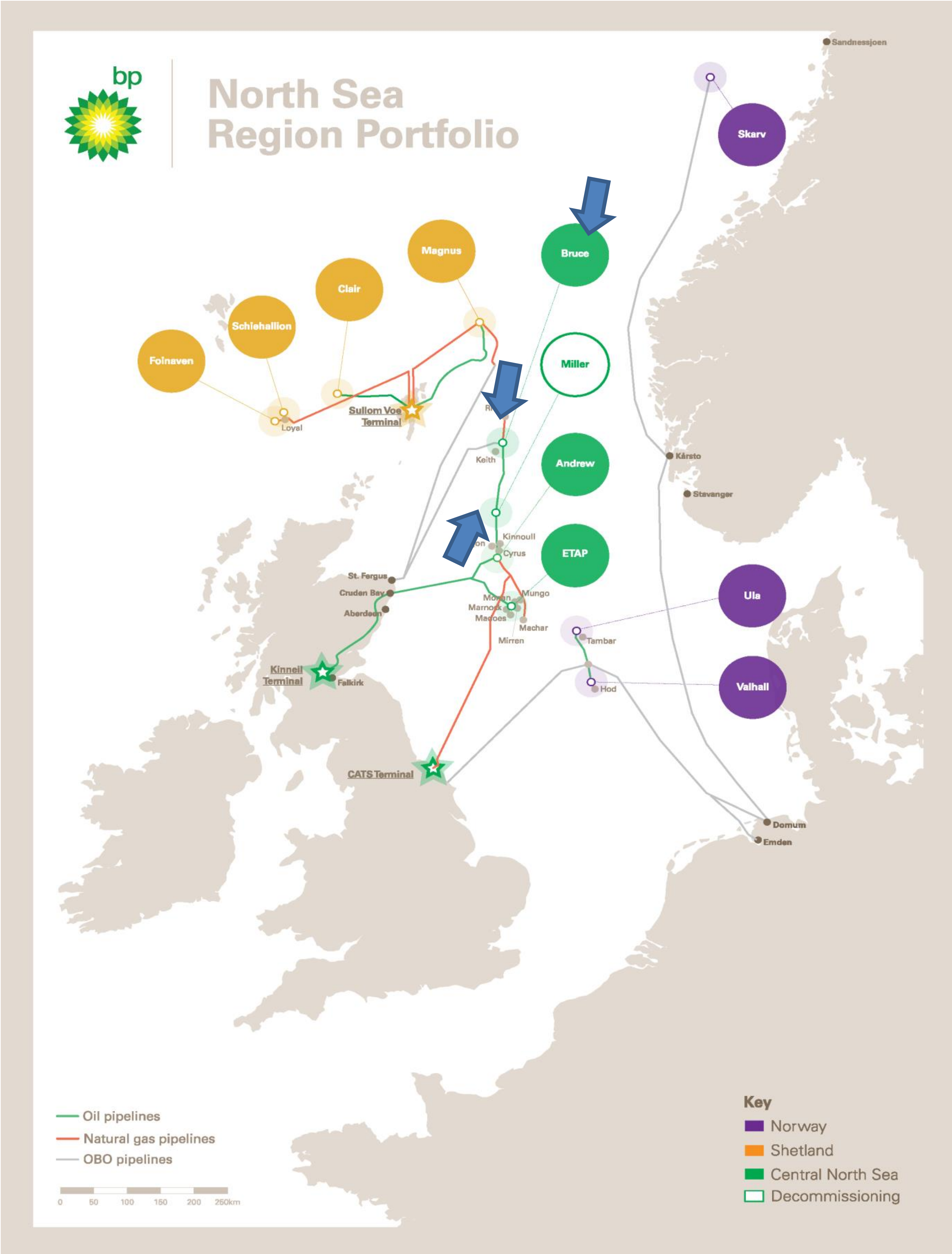
GR-MAB (DCR)/pl

2.0 Introduction

At the request of BP, Ryder Scott has completed an evaluation of three oil and gas fields in which BP owns an interest located in British waters of the North Sea. The fields that we evaluated are the Bruce, Keith and Rhum fields, all of which are operated by BP. A summary table of the assets evaluated by us is shown below, followed by a map showing the relative position of these fields in the North Sea area.

	Oil and Gas Assets in the British North Sea						
Field Name	**Operator**	**Interest**	**Status**	**License Expiry Date**	**License Area**	**License Area Km2**	**Comments**
Bruce	BP	36.00%	Producing	2 years after CoP	9/8a, 9/9a, 9/9b	104 km2	None
Keith	BHP to BP in 2015	34.83%	Producing	2018	9/8a	7 km2	Extension expected
Rhum	BP	50.00%	Producing	2018	3/24b, 3/29a, 3/29b, 3/29d	141 km2	Extension expected

The report details the license interests and the reserves and contingent resources attributable to the assets. It consists of a technical evaluation of the BKR producing assets, including planned further development, but prospectivity was not included in the scope of the report. The gross and net reserves and resources as of June 1, 2017 are detailed in Sections 3, 4 and 5 of this report. Field abandonment (decommissioning) plans, other liabilities and any specific environmental protection issues or obligations are noted in the asset description sections of this report. BP has informed us that all decommissioning costs taken into consideration in this report will remain the responsibility of BP after Serica acquires the interests assessed herein.


bp
North Sea
Region Portfolio
Sandnessjoen
Skarv
Magnus
Bruce
Clair
Schiehallion
Foinaven
Miller
Loyal
Sullom Voe Terminal
Keith
Andrew
Kårsto
Stavanger
Kinnoull
Cyrus
ETAP
St. Fergus
Cruden Bay
Aberdeen
Mungo
Marnock
Machar
Mirren
Tambar
Ula
Kinneil Terminal
Falkirk
Hod
Valhall
CATS Terminal
Domum
Emden
Oil pipelines
Natural gas pipelines
OBO pipelines
0 50 100 150 200 250km
Key
Norway
Shetland
Central North Sea
Decommissioning

Two of the blocks are approaching the expiry date; however, based on past experience with the UK government, BP is confident that licenses will be extended as needed. In this report, it was assumed that such contract extensions will be realized until the Cessation of Production (CoP) is reached.

As we have stated in the Executive Summary section of this report, we have prepared our estimates of reserves, future production and income based on CoP estimates for each field using escalated future price and cost parameters supplied by BP. We refer to this case using escalated cost and price parameters as the SPE-PRMS Forecast Case. Such forecasts were based on projected escalations or other forward looking changes to current prices and/or costs as noted herein. The results of our third party study are presented above in the “Executive Summary” section of this report and below in Section 5.0, “Summary of Total Reserves and Contingent Resources.”

3.0 Description of Reserves and Contingent Resources

3.1.1 Reserves and Contingent Resources Included in this Report

The proved, probable and possible reserves, and 2C contingent resources included herein conform to the definitions of reserves and contingent resources sponsored and approved by the Society of Petroleum Engineers (SPE), the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE) as set forth in the 2007 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (SPE-PRMS). Abridged versions of the SPE/WPC/AAPG/SPEE reserves terms and definitions used herein are included as attachments to this report and entitled “Petroleum Reserves and Resources Classification and Definitions” and “Petroleum Reserves and Resources Status Definitions and Guidelines.”

3.1.2 Reserves and Resources Classification

Recoverable petroleum resources may be classified according to the SPE-PRMS into one of three principal resource classifications: prospective resources, contingent resources, or reserves. Discovered petroleum resources may be classified as either contingent resources or as reserves depending on the chance that if a project is implemented, it will reach commercial producing status (i.e. chance of commerciality). The distinction between various “classifications” of resources and reserves relates to their discovery status and increasing chance of commerciality. Commerciality is not solely determined based on the economic status of a project which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions addressed in the determination of commerciality also include technological, economic, legal, environmental, social, and governmental factors. While economic factors are generally related to costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes. At BP’s request, this report addresses those quantities that may be classified as reserves and 2C contingent resources.

3.1.3 Reserves and Resources Uncertainty

All reserve and resource estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater than or less than the estimated quantities determined as-of the date the estimate is made. 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. Estimates will generally be revised only as additional geologic or engineering data becomes available or as economic conditions change.

Reserves are “those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.” The relative degree of uncertainty may be conveyed by placing reserves into one of two principal categories, either proved or unproved.

Proved oil and gas reserves are “those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.”

Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Probable reserves are “those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.” For probable reserves, it is “equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves” (cumulative 2P volumes). Possible reserves are “those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than probable reserves.” For possible reserves, the “total quantities ultimately recovered from the project have a low probability to exceed the sum of the proved plus probable plus possible reserves” (cumulative 3P volumes).

The reserves included herein were estimated using deterministic methods and are presented as cumulative quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. For reserves using the deterministic cumulative approach, quantities of reserves are aggregated as proved (1P), proved+probable (2P), and proved+probable+possible (3P) based on their individual level of uncertainty. Under the deterministic cumulative approach, 1P denotes the low estimate, 2P denotes the best estimate and 3P denotes the high estimate.

Contingent resources are “those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.”

The contingent resources included herein were estimated using deterministic methods and presented as cumulative quantities. For contingent resources estimated using the deterministic cumulative approach, quantities of contingent resources are estimated and assigned as 1C, 2C or 3C based on their individual level of uncertainty for the cumulative volume. Under the deterministic cumulative approach, 1C denotes the low estimate, 2C denotes the best estimate and 3C denotes the high estimate. According to the scope of work of this report, only the 2C contingent resources were estimated.

The reserves and resource volumes attributable to the different reserve and resource classifications that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable. 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 or prospective resources will not achieve commercial production. Moreover, estimates of reserves and resources may increase or decrease as a result of future operations, effects of regulation by governmental agencies or geopolitical risks. As a result, the estimates of oil and gas reserves and resources have an intrinsic uncertainty. The reserves and contingent resources included in this report are therefore estimates only and should not be construed as being exact quantities. They may or may not be actually recovered; and if recovered, they could be more or less than the estimated amounts.

3.1.4 Possible Effects of Regulation

Ryder Scott did not evaluate country and geopolitical risks associated with the areas in which these assets are located. BP's operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include matters relating to land tenure and leasing, the legal rights to produce hydrocarbons including the granting, extension or termination of production sharing contracts, the fiscal terms or various production sharing contracts, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and foreign trade and investment and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of reserves and contingent resources actually recovered and amounts of income actually received to differ significantly from the estimated quantities.

At your request, we have used a 40% flat corporate tax rate and no provision was made for Petroleum Revenue Taxes (PRT). Although in the future PRT will likely be paid by the working interest owners of these properties, it was beyond the scope of work of this report to determine the amounts of such taxes and the proportionate liability to each working interest owner.

The estimates of reserves and contingent resources presented herein were based upon a detailed study of the subject properties; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liability to restore and clean up damages, if any, caused by past operating practices

3.1.5 Methodology Employed for Estimates of Reserves and Resources

The estimation of reserve and resource quantities involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas, and the second determination results in the estimation of the uncertainty associated with those estimated quantities. The process of estimating the quantities of recoverable oil and gas reserves and resources relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves and/or resources. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data, and the subsequent interpretation of this data, may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of recoverable hydrocarbons is identified, the evaluator must determine the uncertainty associated with the incremental quantities of those recoverable hydrocarbons. If the quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity is addressed by the reserve or resource category assigned by the evaluator. Therefore, it is the categorization of incremental recoverable quantities that addresses the inherent uncertainty in the estimated quantities reported.

Estimates of reserve and resource quantities and their associated categories or classifications may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of the recoverable quantities and their associated categories or classifications may also be revised due to other factors, such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks, as previously noted herein.

The methodology employed that was specific for each field/asset is summarized below and discussed in more detail under separate tabs in this report.

Bruce: Performance methods were used, primarily decline curve analysis of rate versus time and rate versus cumulative production.

Keith: The performance method, decline curve analysis, was utilized.

Rhum: The volumetric method was the main method used to determine the 1P Original Gas in Place (OGIP) and the material balance method to determine the 2P and 3P OGIP for this field. The recovery factors (RFs) used were 70%, 74% and 78% for the 1P, 2P and 3P reserve volumes, respectively. These factors were estimated using a BP simulation study and a nodal analysis model on the delivery system.

3.1.6 Assumptions and Data Considered for Estimates of Reserves

To estimate recoverable oil and gas reserves and resources and related future net cashflows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly. Under the SPE-PRMS Section 2.2.2 and Table 3, proved reserves must be demonstrated to be commercially recoverable under defined economic conditions, operating methods and governmental regulations from a given date forward. We apply the same criteria for economic producibility to the 2P and 3P reserves.

BP has informed us that they have furnished us with all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecasts of future production, we have relied upon data furnished by BP with respect to production and well tests from examined wells, geological structural and isochore maps, well logs, core analyses, and pressure measurements. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data supplied by BP.

Below is the list of BP professionals that furnished all the information for this evaluation:

Name	Role	Data / Info Provided
Gary Hepburn	BKR Reservoir Engineer	Production history data, Rhum Full Field Simulation model
Niels Nouwens	BKR Base and Res Management Team Lead	Description & detail of future Projects
Zoë Sayer	Lead Geologist	Static sub-surface description, maps etc.
Roger Skinner	BP North Sea Reserves Authority	Reserves & Resources Montages collated key exhibits & text supporting booked volumes
Bernice Walker	BKR Commercial Lead	Commercial Issues
Alex Beaney	BKR Commercial Analyst	Economic Inputs & Model

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves and contingent resources reported herein.

3.1.7 Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were estimated by using the results of the nodal analysis which included the deliverability information from each of the wells. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by BP. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

3.1.8 Hydrocarbon Prices

Future income projections are included in this report and are based on an Excel economic model provided by BP. We have reviewed this economic model and believe it to be a reasonable estimate of the fiscal regime and conditions governing the production from the fields. Ryder Scott cash flow projections were used to determine the assessment of the CoP and economic limit of each field. The product prices which were actually used for each property reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by BP. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness;

however, we have not conducted an independent verification of the data used by BP to determine these differentials.

SPE-PRMS Forecast Case Prices

For the Forecast Case, the future hydrocarbon price parameters and escalations used were specified by BP are noted below and were used by Ryder Scott in the economic assessment of each field.

Year	Oil / Condensate $/bbl	NGL $/bbl	Gas GBp/therm	Gas $/MMbtu
2017	51.11	34.07	41.79	5.38
2018	51.86	34.57	42.48	5.47
2019	52.93	35.29	43.36	5.58
2020	53.98	35.99	43.66	5.62
2021	55.15	36.77	43.82	5.64
2022	56.48	37.66	43.88	5.65
2023	57.61	38.41	44.75	5.76
2024	58.77	39.18	45.65	5.88
2025	59.94	39.96	46.56	6.00
2026	61.14	40.76	47.49	6.12
2027	62.36	41.58	48.44	6.24
2028	63.61	42.41	49.41	6.36
2029	64.88	43.25	50.40	6.49
2030	66.18	44.12	51.41	6.62

The BP NGL price stream is based on 66.7% of the BP Brent oil price. The above gas price is adjusted for each field based on the gas quality energy factor. In this analysis, the exchange rate from GBP to US$ is held constant at $1.288/GBP.

Gas Quality Energy Factor	Bruce	Rhum	Keith
Therm/mcf	11.10	9.8	11.10
Btu/scf	1110	980	1110

3.1.9 Costs

Operating costs for the properties included in this report were furnished by BP and are based on their operating expense reports. Such costs include only those costs directly applicable to the properties. The operating costs include a portion of general and administrative costs allocated directly to the properties. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by BP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the properties. These costs were used by Ryder Scott in the assessment of CoP, in determining economic viability of development projects, economic analysis and for the purpose of classifying volumes as reserves.

Development costs were furnished to us by BP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. Decommissioning costs were furnished to us by BP and are based on its assessment of works required to comply with current legislative requirements.

Because of the direct relationship between volumes of undeveloped reserves and resources and development plans, we include in the undeveloped category only reserves and resources assigned to undeveloped locations that we have been assured will definitely be executed. BP has assured us of their intent and ability to proceed with the development activities included in this report, and that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans.

SPE-PRMS Forecast Case Costs

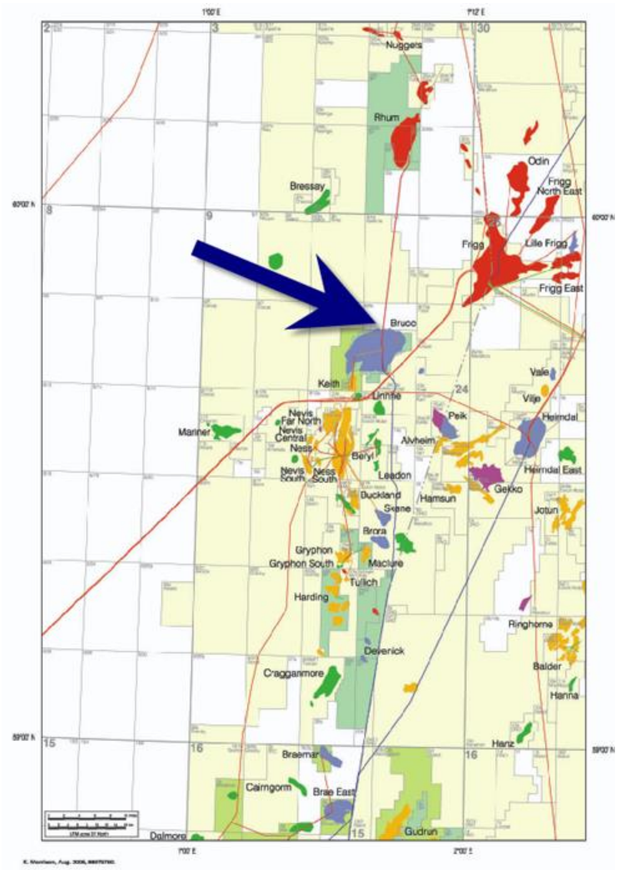
For the Forecast Case, current costs were held constant for the remainder of 2017 and then beginning in 2018 they were escalated annually at the rate of 2.0 percent until the major hydrocarbon product reaches its final price. Projected costs vary each year based upon maintenance schedules and other factors.

4.0 Overview of the Region, Location and Assets

Ryder Scott has not visited the fields or their facilities; however, based on information provided by BP, the facilities can be described as stated below.

4.1 Bruce Field

The Bruce field is operated by BP (37% ownership) and was discovered in June 1974. It is located 350 km NE of Aberdeen in Quad 9 of the United Kingdom Continental Shelf (UKCS) at a water depth of 122 m. The Bruce field has an area of approximately 75 km^2 (18,533 acres). The interest for the Bruce field that is evaluated in this report is 36% since BP is planning to retain a 1% interest in this property.



Bruce Field Location (BP)

Field development was sanctioned in 1990, and production started in May 1993. Production peaked in 1995 at 760 million cubic feet of gas per day (MMCFD) and 67,000 barrels per day (bpd) of condensate and oil. This liquid production is primarily condensate. NGL is also extracted through downstream processing. The field produces from 11 reservoir units separated by faulting and had a cumulative production of approximately 3.1 trillion cubic feet of gas (TCF) at June 1, 2017. Production from January to May 2017 averaged 73 MMCFD of gas and 2,023 barrels per day (bpd) of oil and condensate. The field utilizes 3 platforms and a sub-sea manifold for production. Gas compression was installed in 2004. The Rhum field is also tied back to the Bruce complex and was re-started in late

2014 after being shut-in since November 2010 due to EU sanctions because of partial Iranian ownership. Gas from the Bruce, Keith and Rhum fields is processed at the Bruce complex and then transported through the Frigg pipeline (operated by TOTAL) to St. Fergus for NGL extraction. The condensate is separated at the Bruce complex and then exported through the Forties Pipeline System to Cruden Bay. Current single compression capabilities for handling of the three fields, is set at 250 MMCFD. It is expected that export gas deliveries from other fields between 2018 and 2020 will increase the pressure in the system from approximately 115 barg to 140 barg. This will reduce the capacity of the compressor to approximately 210 MMSCFD. With the dual compression system available in the complex the delivery of gas can reach 420 MMSCFD. This is sufficient capacity to handle all the volumes unconstrained from the three fields.

The Bruce installation comprises three separate platforms, PUQ, D and CR. The PUQ is bridge linked to D, which in turn is bridge linked to CR. The cellar decks stab directly into the jacket structures and are welded out. The PUQ platform comprises the four legged, tubular steel P80 jacket, piled to the seabed, supporting topsides which consists of three large modules. The P10 Cellar Deck contains the platform utilities, export equipment and Central Control Room. Located above P10 on the east side is the P20 process module, which houses the power generation plant and all major production equipment. P20 in turn supports P30, the flare tower, at its northeast corner. The P40 accommodation module is located above, and to the west end of P10. P40 supports the helideck. The drilling (D) platform is a four legged, tubular steel structure, piled to the seabed. The D80 jacket supports the D10 module which contains the drilling facilities and the wellbay area. This module in turn supports the D20 drilling substructure, skid base and derrick on its northern side.

The D platform is located above a subsea template. The piled subsea template was placed on the seabed in 1990 to permit the drilling of 11 wells prior to the installation of the jacket. The template is an all welded steel structure, used to control the plan relationship, levelness and verticality of the production wellheads installed at the seabed. It additionally provided temporary support for the wellheads which were tied back to the platform after the jacket and topsides had been installed. The template measures 14 m x 8 m. The structure contains 16 wellhead receptacles, arranged in a 4 x 4 array at 2.59 m centers.

The CR platform comprises the four legged, tubular steel C30 jacket, piled to the seabed. It supports module C10 containing pig receivers/launchers, slug catcher, decommissioned gas turbine driven compressor, chemical injection facilities and an associated local equipment room, and module C60 containing the Rhum separator and subsea chemical injection facilities, two gas turbine driven compressors and associated inlet scrubbers, suction and discharge coolers and an associated local equipment room. An inboard deck crane is supported on the southwest corner. The Rhum riser is located within a dry, vented caisson supported outboard off the northeast leg of the CR jacket. Three risers are supported inboard off the southwest corner leg. C10 comprises a two-deck module. C60 comprises two main decks, a mezzanine level and weather deck.

PUQ and D are joined by the P60 bridge which spans from P10 to D10 at El +31.5 m. The bridge is a tubular steel structure which carries pipelines containing hydrocarbons, and has a span of approximately 48 m. D and CR are linked by the C40 bridge at El +32.6 m. It is a tubular steel structure carrying a walkway, piping and cable trays. Its span is approximately 37.5 m. Pancake structures on top of the bridge structures support the pipework required to transfer Rhum fluids from CR to the PUQ and Bruce/Western Area Development (WAD)/Keith fluids from the PUQ to the booster compression equipment on CR and then returning them to the PUQ for further compression, drying and export.

Gas is exported from the PUQ platform via a 5 km long, 32" diameter pipeline to the Frigg Gas Export Pipeline System. The gas then flows to the St Fergus Terminal for treatment to sales specification and export. Liquids are exported from the PUQ platform via a 254 km long, 24" diameter pipeline to the Forties Unity platform, and into the Forties Pipeline System for subsequent treatment at the Kinneil Terminal. Production of oil started in May 1993 with the first sales of contracted gas starting in October 1993.

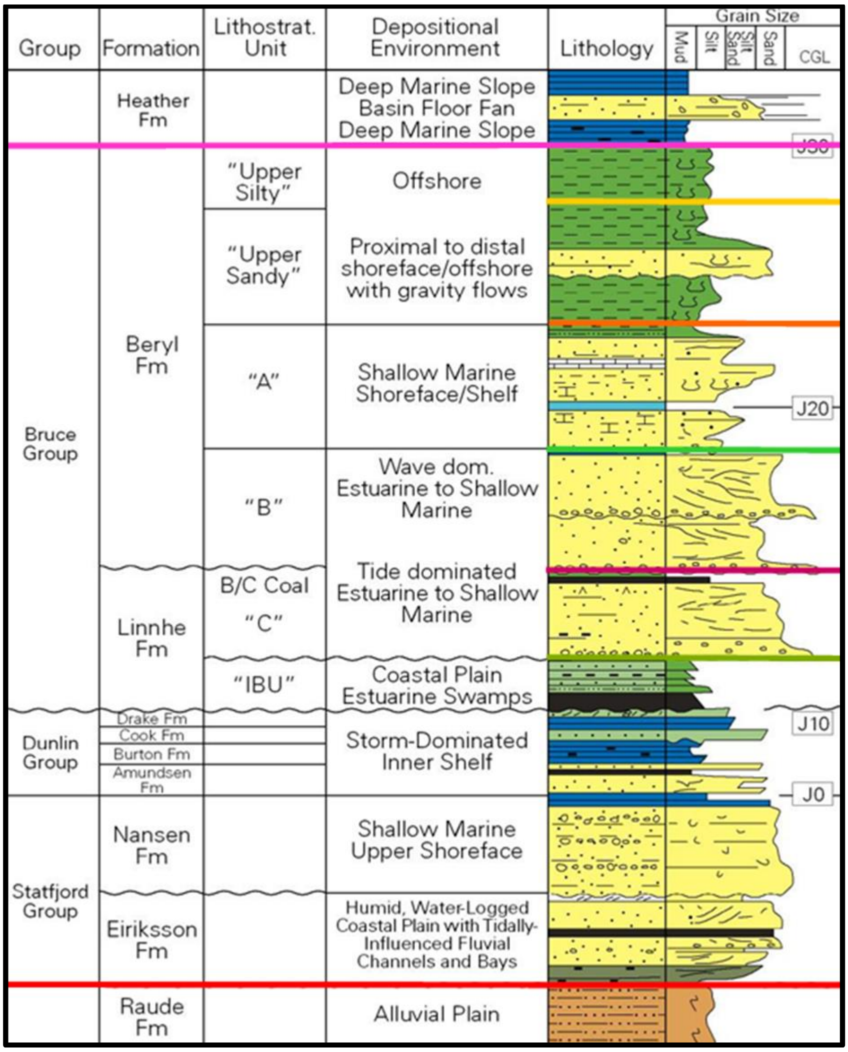
4.1.1 Reserves Discussion

4.1.1.1 Geological Discussion

Stratigraphy and Deposition

Production of hydrocarbons in Bruce is confined to the five reservoir quality lithostratigraphic layers of the Middle Jurassic Bruce group: the Upper Silty, Upper Sandy, A, B, and C units. These units are made up of siltstones and sandstones deposited as part of the middle-Jurassic Brent delta system. This system produced deposits in Offshore, Shelf, Shallow Marine, and Estuary environments in accordance to changes in sea-level. These units follow an upward fining trend which results in vertically degrading reservoir quality from the C unit to the Upper Silty. In general, stratigraphy in the field is fairly continuous with wells encountering all five units, with the exception of cases where post depositional faulting has created portions of missing section. Production is generally comingled across all five reservoir units when encountered.

The figure below shows the stratigraphic column for the Bruce field.

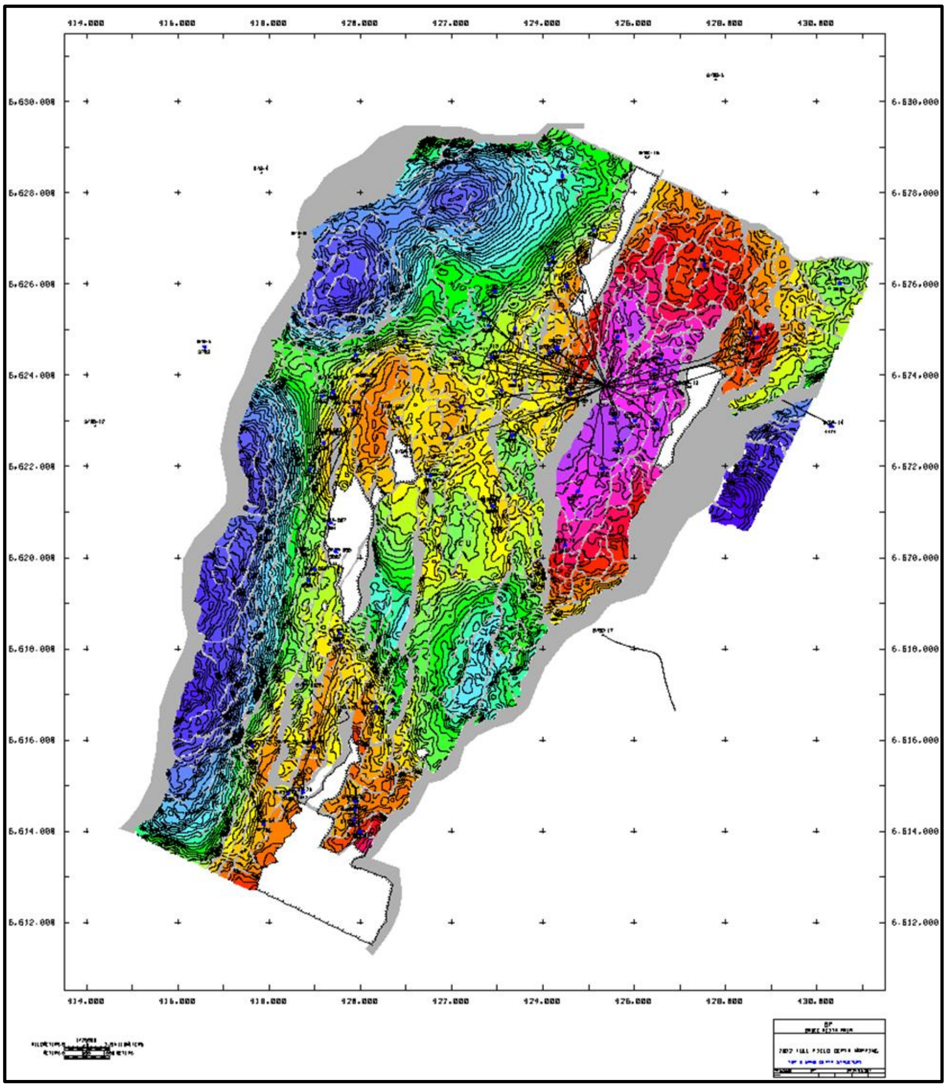


Bruce Field Stratigraphic Column (source - BP)

Structure

Unlike the stratigraphic distribution in the unit, the structural model in Bruce is very complex, with 11 primary reservoir panels (fault blocks) and potential for more localized compartmentalization within each panel. Multiple episodes of geologic movement in the reservoir have left the field dominated by large north-south trending faults cut by smaller NW-SE trending faults. The WAD rollover is defined by its collapse into a large listric fault forming the field's western boundary. In general, faults in the field are considered sealing and given their frequency in the field, compartmentalization is common. Given the significant amount of depletion in the field, fault seal breakdown may be present, but has not been proven. Originally, the field was seismically surveyed using streamer data, but the installation of an ocean bottom cable (OBC) in 2002 has resulted in a much greater definition of the structural features of the field. This OBC data has also allowed for the use of 4D seismic to identify isolated compartments. As of the date of this study, the seismic data for the field had not been assimilated into one integrated model. This fragmentation is also present in the simulation model and is based on the presence of large sealing faults in the field.

The figure below is a depth structure map of the top of the B Sand in the Bruce field.



Top of the B Sand Depth Structure Map (BP)

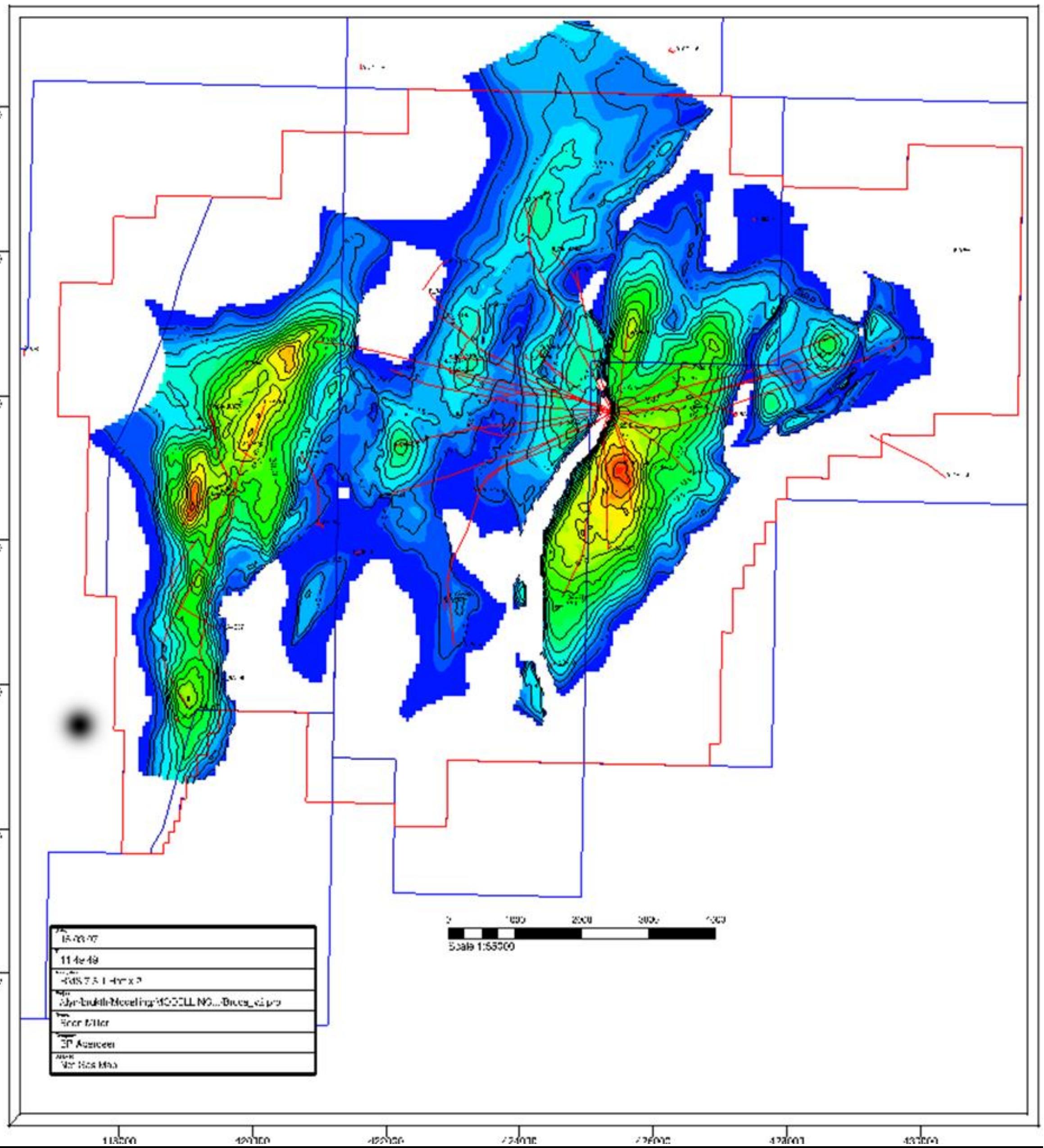
Fluid Contacts

The hydrocarbons in the field consist of a large column of gas condensate surrounded by an oil rim of varying thickness. Compartmentalization within the field has resulted in a diversity of fluid contacts attributed to 11 regional trends based on structural complexity as well as the depletion of the reservoirs. Evaluation of fluid contacts within the reservoirs is generally localized to individual fault compartments. RFT data obtained across the field indicate that there are three distinct reservoir pressure gradients, the Eastern High plus Central areas, the WAD, and the Eastern terraces.

Petrophysical Properties

Review of the petrophysical interpretation provided by BP demonstrates a fairly good tie between core and log derived porosity values; however, we observed that BP utilized the effective porosity values, as appropriate, for the upper units, whereas total porosity values were used to describe the lower units. Considering the reserve evaluation of the field is performance driven, the deviation in porosity estimation techniques is inconsequential. Porosity values observed in the units range from 8% to 16% and are consistent with the fining upward trend of the Bruce Group. Water saturation is described through the use of capillary pressure functions to tie back to height above the free water level. This is considered a reasonable method for describing saturation in the simulation models and should take into account movement in the free water level based on compartmentalization in the reservoir. Water saturation values range from 20-60%, depending on the formation and fault block. Review of the core data demonstrates a good general trend between porosity and permeability, which is further refined when tied back to facies type.

Below is a total net gas isochore map across all developed reservoirs.



Bruce Field - Total Net Gas Isochore Map (BP)

4.1.1.2 Current Field Development and Future Plans

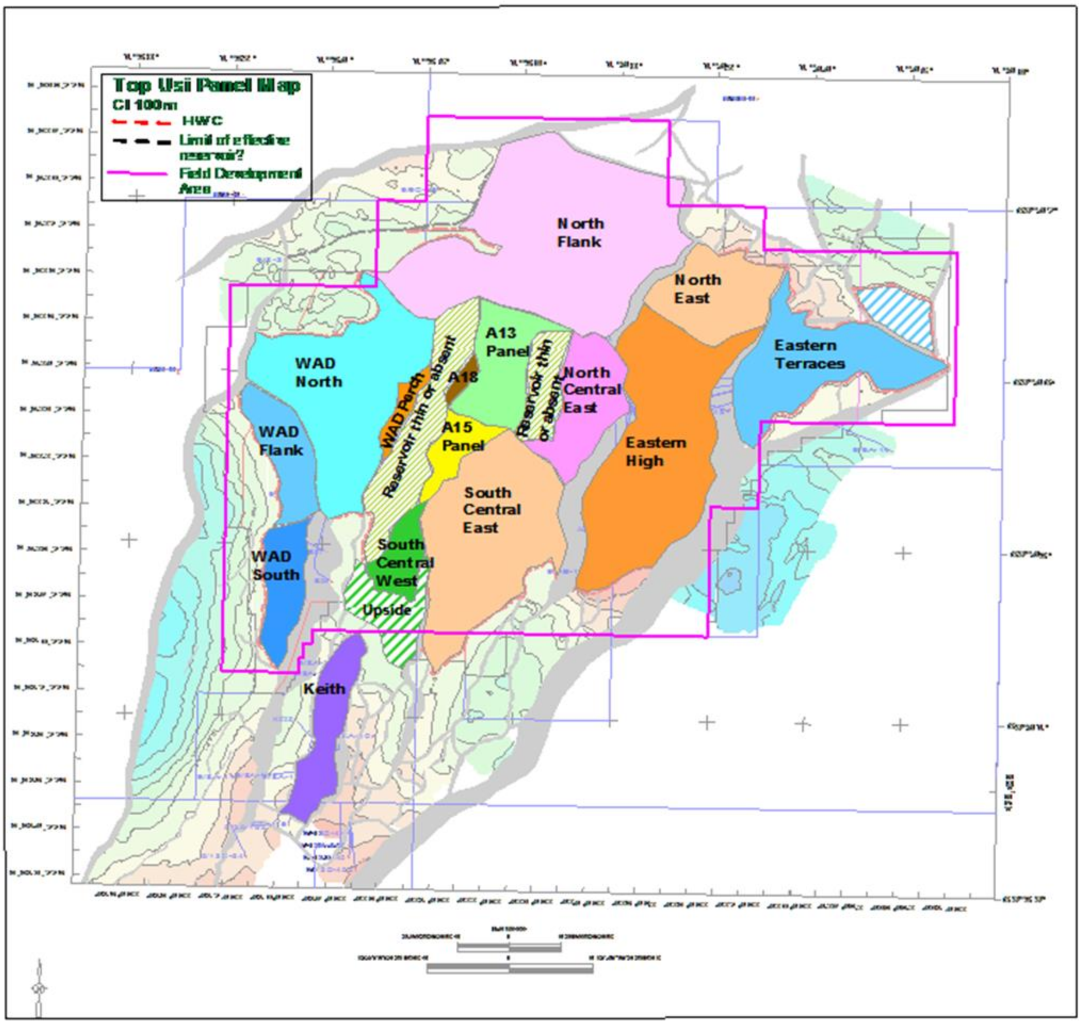
The first phase (Phase 1) of the Bruce field development was sanctioned in 1990, on the basis that all of the gas condensate present within the Bruce Group and the Turonian Limestone Reservoir would be developed under blowdown. The Phase 1 facilities comprised a drilling and wellhead platform (D) with 32 slots, bridge-linked to a process, utilities and quarters (PUQ) platform. The PUQ platform has accommodation for a maximum of 168 people.

The second phase of development of the Bruce Field commenced in 1998. This development of the Western and South Central Areas of the field comprised a subsea well scheme, (the Western Area Development - WAD) tied back to a reception module sited on a small additional reception/compression platform (CR), bridge-linked to the existing D platform. There are 7 subsea wells in the Western Area Development which are tied back to the WAD subsea manifold, one of the wells was dry and is suspended. To maintain well deliverability, Booster Compression was completed in 2000. This involved an extra MP compression unit on all three existing compression trains on PUQ platform and a change in operating pressures of the process plant allowing a reduction in wellhead flowing pressure from 70 to 35 bara.

The field was originally discovered in 1974 and was delineated with 26 appraisal wells. Development commenced in 1990 with the first of production coming on in 1993. To date there are over 60 well penetrations in the field with 21 active production wells. For this evaluation BP presented a hydraulic fracturing project for 4 wells in 2017. These wells were A12z, A14, A17y and the A26y.

There are no current projects in the contingent resources categories. There was one well to be drilled in the Bruce area that was classified as exploratory and therefore was not included in this report as being beyond the scope of this study. Additionally, to the fracturing project Ryder Scott estimated incremental volumes for a work project being done by BP to lower the suction pressure 1 bar at the compression system. Some of the incremental volumes were located in the 1P category and the rest of the volumes were assigned in the 2P category to reflect greater uncertainty in recovery. This work is scheduled to take place in September 2017.

The panels map shown below shows the compartmentalization in the Bruce field.



BP Development Panels Map (BP)

4.1.1.3 Reserves Estimation Methodology

The Bruce field is a complex structure composed of 11 fault-separated reservoir units. The field is quite mature, and no undeveloped reserves for new wells were projected. The only undeveloped reserves projected were attributed to the four hydraulic fractures scheduled for 2017. The methodology used in estimating the incremental volumes from the hydraulic fractures was analogy with other gas wells of similar conditions. Ryder Scott only considered the hydraulic fracture for well A14 to be proved. The estimated volumes from the other three hydraulic fractures of wells A12z, A17y and the A26y were classified as probable undeveloped. Ryder Scott estimated the incremental volumes resulting from the reduction in suction pressure using analogy with the historical results of similar operations. These reserves were assigned to the proved and probable developed producing category depending upon the certainty of recovery. Producing reserves were projected from decline curve analysis using rate versus time and rate versus cumulative historical production. Ryder Scott did not map or perform an independent volumetric analysis of this field but used the BP volumetric data as a means for estimating the recovery factors. The total field gas recovery factor was estimated to be 62%.

4.1.1.4 Reserves Summary

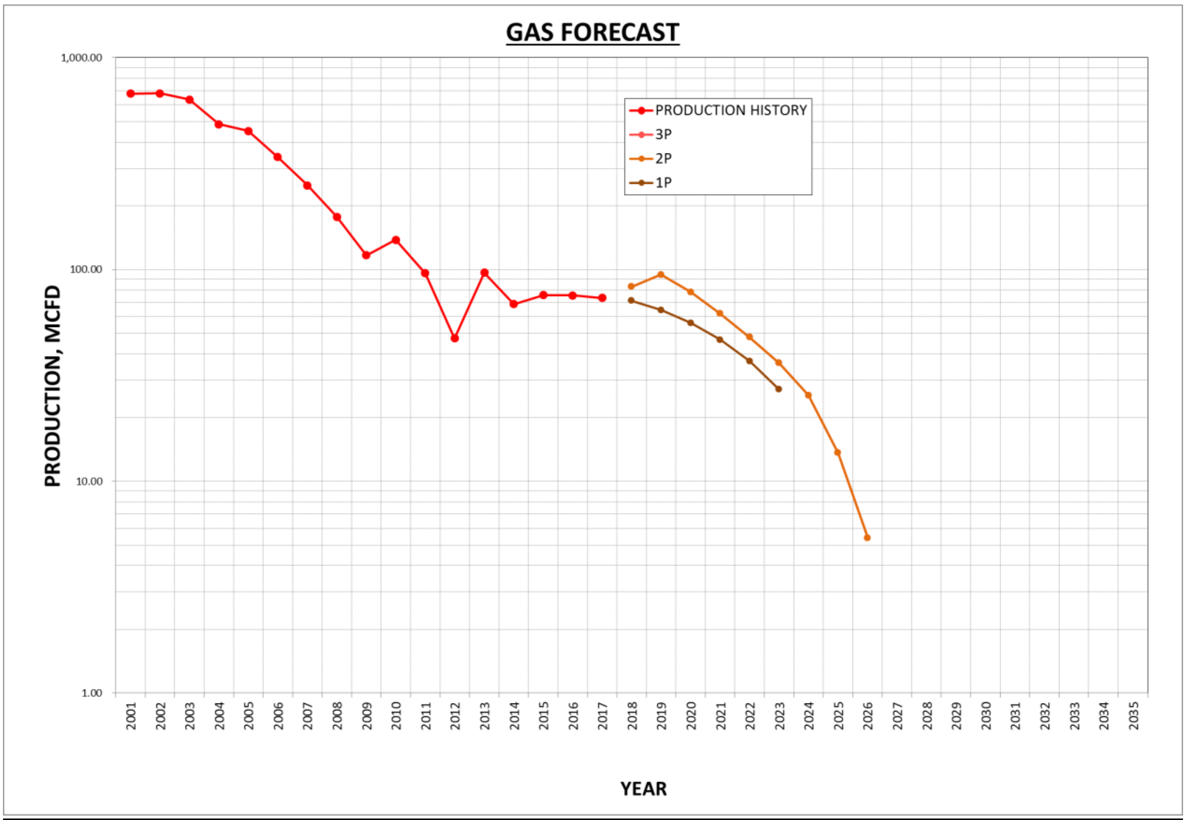
The table below presents the Gross reserves for the Bruce field.

BRUCE FIELD - GROSS RESERVES AS OF JUNE 1, 2017									
		PROVED (1P) Reserves							
		Developed			Total	Cumulative	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	Proved	Production	Recovery	Factor
OIL/COND	– MBarrels	1,580	233	19	1,832			
PLANT PRODUCTS	– MBarrels	2,253	213	41	2,507			
GAS	– MMCF	78,437	7,198	1,441	87,076	3,066,209	3,158,095	62%
FUEL GAS	– MMCF	4,430	381	0	4,810			
Total	– MMBOE	18.1	1.8	0.3	20.2			
		Proved + Probable (2P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	2P	Probable	Recovery	Factor
OIL/COND	– MBarrels	1,656	397	690	2,743	911		
PLANT PRODUCTS	– MBarrels	2,408	441	742	3,591	1,084		
GAS	– MMCF	83,913	15,118	25,357	124,388	37,312	3,197,047	62%
FUEL GAS	– MMCF	6,007	374	69	6,451	1,640		
Total	– MMBOE	19.6	3.5	5.8	28.9	8.4		
		Proved + Probable+Possible (3P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	3P	Possible	Recovery	Factor
OIL/COND	– MBarrels	1,656	397	690	2,743	0		
PLANT PRODUCTS	– MBarrels	2,408	441	742	3,591	0		
GAS	– MMCF	83,913	15,118	25,357	124,388	0	3,197,047	62%
FUEL GAS	– MMCF	6,007	374	69	6,451	0		
Total	– MMBOE	19.6	3.5	5.8	28.9	0.0		
Used CoP of YE2023 for 1P and YE2026 for 2P. Note that gas above needs to be reduced by 10% shrinkage factor before sales.								

Table of Bruce Field Gross Reserves as of June 1, 2017

4.1.1.5 Reserves Forecast

Below is a graph showing the historical and gas forecast production profile for the Bruce field 1P and 2P reserves.



Plot of Bruce Gas Production History and Forecast

The profile of gross 1P production is shown in the table below. Ryder Scott estimated the 1P CoP at year-end 2023 for this field based on economics. The volumes from 2023 until the end of 2026 are considered to be 2P reserves. The CoP for the 2P scenario was estimated at 2026. BP has a 37% ownership in this field and is the operator; however, in this report a 36% interest is appraised in consideration of BP's retention of 1% interest.

	BRUCE FIELD			
1P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	288	326	11,167	577
2018	455	543	18,710	802
2019	372	484	16,745	845
2020	294	420	14,638	721
2021	207	328	11,488	643
2022	136	236	8,312	621
2023	80	170	6,015	602
2024	45	97	3,456	581
2025	20	35	1,237	541
2026	11	20	720	518
2027	7	6	210	477
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
1P TO YE2023	1,832	2,507	87,076	4,810
CUM (06/2017)			3,066,209	
ULTIMATE TO YE2023			3,158,095	
RS estimated CoP at 2023. Note that gas above needs to be reduced by 10% shrinkage factor before sales. BP has a 36% Working Interest in this field.				

A table of the 2P production profile is shown below. Ryder Scott estimated the 2P CoP at year-end 2026 for this field based on economics. BP has assured Ryder Scott that it does not expect any material Capex expenditure (over and above normal operating expenditure) to maintain production until 2026. Production thereafter is classified as 2C resources.

	BRUCE FIELD			
2P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	352	383	13,103	577
2018	709	811	27,858	802
2019	557	687	23,722	845
2020	425	567	19,681	721
2021	296	433	15,108	643
2022	199	322	11,286	621
2023	114	220	7,761	602
2024	60	111	3,912	581
2025	20	35	1,237	541
2026	11	20	720	518
2027	7	6	210	477
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2P TO YE2026	2,743	3,591	124,388	6,451
CUM (06/2017)			3,066,209	
ULTIMATE YE2026			3,197,047	
RS estimated CoP at 2026. Note that gas above needs to be reduced by 10% shrinkage factor before sales. BP has a 36% Working Interest in this field.				

4.1.2 Contingent Resources Discussion

4.1.2.1 General Objective of Contingent Resource Projects

The descriptions of the structural and stratigraphic features of the reservoir areas where the resources are located in Bruce field are described in the section associated with reserves. The general objectives of the contingent resources in Bruce field are primarily commercial and are associated with the economic feasibility of further development.

4.1.2.2 Resources Estimation Methodology

In general, future resource volumes associated with further commercial development of the current producing wells and projects, were estimated by using the same methodologies as used for the estimation of reserves. There are no contingent resource volumes associated with new projects.

For the period of production beyond the CoP, the production decline forecast was extended from YE2026 (CoP 2P) to YE2027 and the incremental volume was classified as contingent resources. This results in one extra year of production for this field beyond the 2P CoP of 2026.

4.1.2.3 Contingencies

For the resource projects in the Bruce field, volumes attributed to the period beyond the CoP are contingent upon economic conditions in the future which would result in the commercial recovery of these volumes. Due to the age of the Bruce facilities, extension of Bruce production beyond the 2P CoP may require facility upgrades.

4.1.2.4 Resources Summary

Below is a table summarizing the 2C Contingent Resources of the Bruce field.

GROSS VOLUMES - BRUCE FIELD (BP 36% WORKING INTEREST)						
	1C		2C		3C	
Project	MBBL	MMCF	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP			7	210		
TOTALS			7	210		

Table of Bruce Field 2C Contingent Resources

4.2 Keith Field

The Keith field is located 6.8 km south of the Bruce field platform at a water depth of 120 meters. It is comprised of a single subsea gas lifted well, K01, which is tied back to the Bruce Platform. The field was discovered in 1983, but was not developed and put on production until 2000. Until recently, the field was on record operated by BHP although it is tied to the Bruce platform, which is operated by BP. Recently, BHP transferred operatorship to BP. Several appraisal wells tested oil from DSTs in this field, but were never completed. Additionally, six dry holes were drilled in the field. The current producing well is nearing end of life, which is projected in 2023. Production from January to May 2017 averaged 838 barrels of oil per day (bopd).

4.2.1 Reserves Discussion

4.2.1.1 Geological Discussion

The Keith field is a panel inside of the larger Bruce complex, lying southwest of the Bruce South Central West panel. Description of Keith's geological features is encompassed in the Bruce Geological Description in section 4.1.1.1.

4.2.1.2 Current Field Development and Future Plans

There are no development projects planned for this field.

4.2.1.3 Reserves Estimation Methodology

The Keith field is quite mature with little remaining production life and no undeveloped reserves. Reserves were projected from decline curve analysis using a rate versus time projection. Ryder Scott did not map or perform an independent volumetric analysis of this field but used the BP volumetric data as a means for estimating the recovery factor. For the total field, the oil recovery factor for proved reserves was estimated to be 22%.

4.2.1.4 Reserves Summary

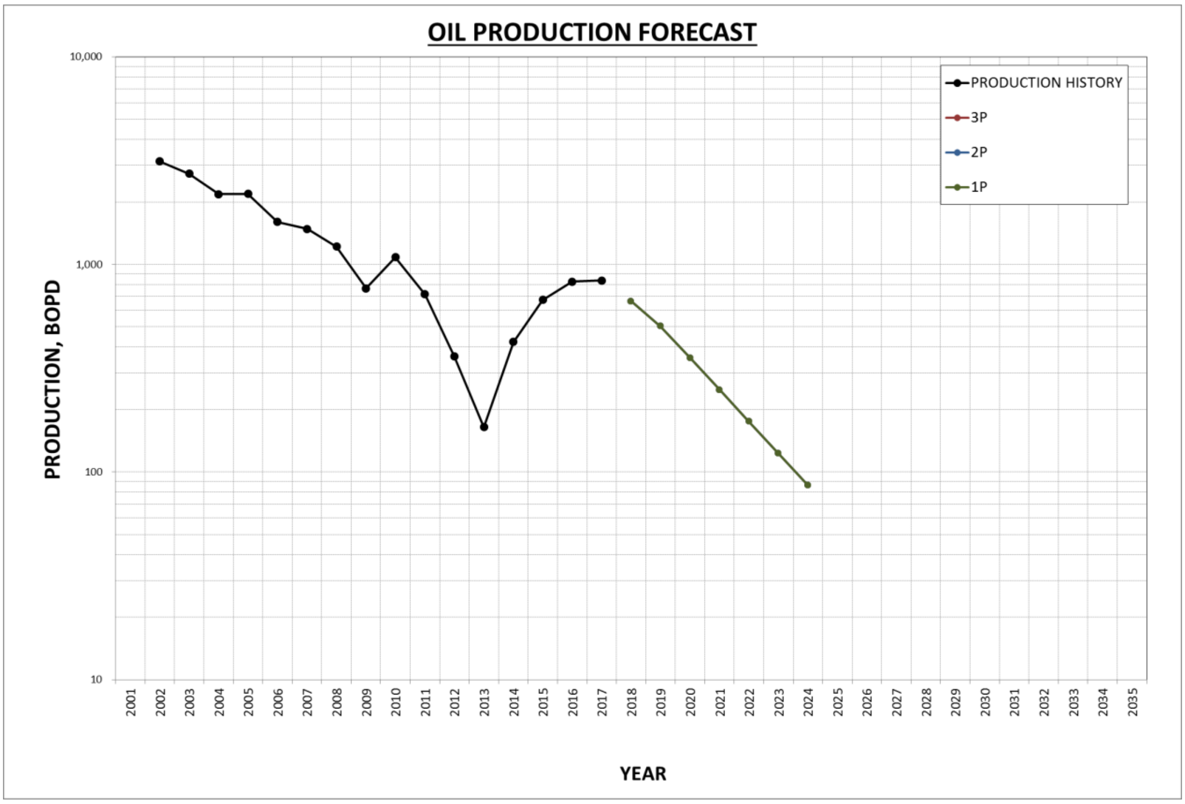
The table below shows the gross reserves for the Keith field.

KEITH FIELD - GROSS RESERVES AS OF JUNE 1, 2017								
		PROVED (1P) Reserves						
		Developed			Total	Cumulative	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	Proved	Production	Recovery	Factor
OIL/COND	– MBarrels	581	0	0	581	9,950	10,531	22%
PLANT PRODUCTS	– MBarrels	112	0	0	112			
GAS	– MMCF	2,049	0	0	2,049			
FUEL GAS	– MMCF	114	0	0	114			
Total	– MMBOE	1.1	0.0	0.0	1.1			
		Proved + Probable (2P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	2P	Probable	Recovery	Factor
OIL/COND	– MBarrels	601	0	0	601	20	10,551	22%
PLANT PRODUCTS	– MBarrels	116	0	0	116	4		
GAS	– MMCF	2,111	0	0	2,111	63		
FUEL GAS	– MMCF	114	0	0	114	0		
Total	– MMBOE	1.1	0.0	0.0	1.1	0.0		
		Proved + Probable+Possible (3P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	3P	Possible	Recovery	Factor
OIL/COND	– MBarrels	601	0	0	601	0	10,551	22%
PLANT PRODUCTS	– MBarrels	116	0	0	116	0		
GAS	– MMCF	2,111	0	0	2,111	0		
FUEL GAS	– MMCF	114	0	0	114	0		
Total	– MMBOE	1.1	0.0	0.0	1.1	0.0		
Used CoP of YE2023 for 1P and YE2024 for 2P. Note that gas above needs to be reduced by 3% shrinkage factor before sales.								

Table of Keith Field Gross Reserves as of June 1, 2017

4.2.1.5 Reserves Forecast

Below is a graph showing the production history and forecast production profile for the Keith field 1P reserves. There were no future work projects planned for this field that would result in incremental reserves. The only 2P projection for this field is the extension of the production life by one year attributed to a better economic profile in the Bruce hub in 2024.



Plot of Keith Oil Production History and Forecast

The profile of gross 1P production is shown in the table below. Ryder Scott estimated the 1P CoP at year-end 2023 for this field based on economics. The volumes from 2023 until the end of 2024 are considered to be 2P reserves. The CoP for the 2P scenario was estimated at 2024. BP has a 34.83% ownership in this field and became the operator in mid-2015.

	KEITH FIELD			
1P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	109	22	405	30
2018	153	30	547	43
2019	111	21	375	40
2020	82	16	295	-
2021	57	11	200	-
2022	40	8	136	-
2023	28	5	92	-
2024	20	4	63	-
2025	6	1	18	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
1P TO YE2023	581	112	2,049	114
CUM (06/2017)	9,950			
ULTIMATE TO YE2023	10,531			
RS estimated CoP at 2023. Note that gas above needs to be reduced by 3% shrinkage factor before sales. BP has a 34.83% Working Interest in this field.				

A table of the 2P production profile is shown below. Ryder Scott estimated the 2P CoP at year-end 2024 for this field. Production from 2025 is categorized as 2C resources.

	KEITH FIELD			
2P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	109	22	405	30
2018	153	30	547	43
2019	111	21	375	40
2020	82	16	295	-
2021	57	11	200	-
2022	40	8	136	-
2023	28	5	92	-
2024	20	4	63	-
2025	6	1	18	-
2026	-	-	-	-
2027	-	-	-	-
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
2P TO YE2024	601	116	2,111	114
CUM (06/2017)	9,950			
ULTIMATE YE2024	10,551			
RS estimated CoP at 2024. Note that gas above needs to be reduced by 3% shrinkage factor before sales. BP has a 34.83% Working Interest in this field.				

4.2.2 Contingent Resources Discussion

4.2.2.1 General Objective of Contingent Resource Projects

The general objectives of the contingent resources in Keith field are primarily commercial and are associated with the economic feasibility of further development.

4.2.2.2 Resources Estimation Methodology

In general, future resource volumes associated with further commercial development of the current producing wells and projects, were estimated by using the same methodologies as the ones used for the estimation of reserves. There are no contingent volumes associated with new projects.

4.2.2.3 Contingencies

The resources in the Keith field attributed to the period beyond the CoP are contingent upon economic conditions in the future which would result in the commercial recovery of these volumes. Due to the age of the Bruce facilities, extended Keith production beyond the CoP may require facility upgrades.

4.2.2.4 Resources Summary

Below is a table summarizing the contingent resources of the Keith field.

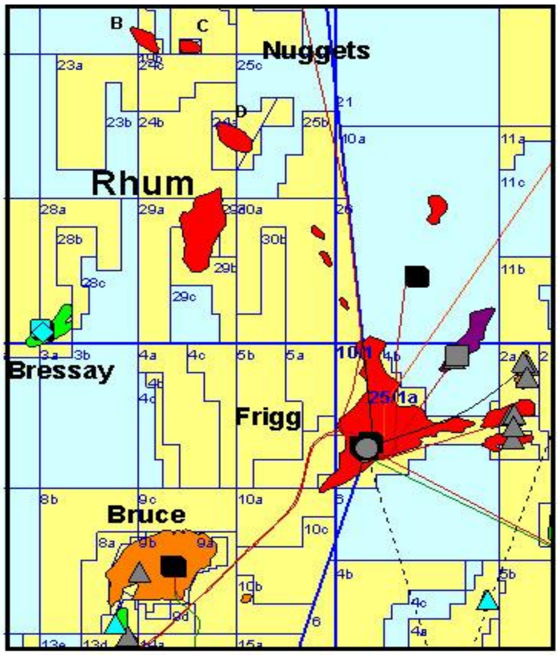
GROSS VOLUMES - KEITH FIELD (BP W.I. 34.83%)						
	1C		2C		3C	
Project	MBBL	MMCF	MBBL	MMCF	MBBL	MMCF
KP-1			6	18		
TOTALS			6	18		

Table of Keith Field 2C Contingent Resources

4.3 Rhum Field

The Rhum field is operated by BP with a 50% ownership interest. The remaining 50% is held by the Iranian Oil Company (IOC) UK. This field was discovered in August 1977 and is located 380 km NE of Aberdeen in the United Kingdom Continental Shelf (UKCS) at a water depth of 109 m. The location of Rhum is shown below.

Rhum Field Location (BP)



Rhum Field – 44 km North of Bruce (BP)

Field development was sanctioned in 2003 and production started in December 2005. Production briefly peaked at 300 million cubic feet per day (MMCFD) of gas shortly after start-up, but the field has generally produced gas in the range of 200-230 MMCFD and condensate at 1300-1500 bpd until the field was shut-in in November 2010. NGLs are extracted through downstream processing at St. Fergus terminal. The field produces gas and condensate from two high pressure (12,423 psia initial pressure), high temperature (296 deg. F) late Jurassic thinly-bedded turbidite sand reservoirs. The gas is sour and corrosive containing both hydrogen sulfide (10-20 ppm) and carbon dioxide (4.0-8.5 %). Production was shut-in in November 2010 as a result of European Union sanctions due to the 50% ownership by the Iranian Oil Company (IOC) UK, but was restarted in October 2014. Production in 2017 has averaged 155 MMCFD and 1,273 bpd of condensate. Production is expected to increase later this year as there will be a code change for maximum percentage of CO_2 concentration that can be delivered at St Fergus terminal. It is expected that the CO_2 percentage acceptable for delivery will go up from 3.8% to 5.5%. This change will allow Rhum to flow unconstrained for the remainder of its life if compressor capabilities permit. Cumulative production is approximately 368 billion cubic feet (BCF) of gas and 2,448 MBarrels of condensate as of June 1, 2017.

Rhum has subsea completions which are tied back to the Bruce platform complex, which lies 44 km south of Rhum. The gas is processed at the Bruce complex and then transported through the Frigg pipeline (operated by TOTAL) to St. Fergus for NGL extraction. The condensate is separated at the Bruce complex and then exported through the Forties Pipeline System to Cruden Bay.

Three wells were completed in the field (R-1, R-2 and R-3); however, one well (R-3) does not produce due to problems related to hydrates buildup. There are plans in 2018 to bring the R-3 to production after a change of completion.

4.3.1 Reserves Discussion

4.3.1.1 Geological Discussion

<u>Stratigraphy & Deposition</u>

Rhum is comprised of low density turbidite sands deposited during the Upper Jurassic within the Kimmeridge clay. These deposits override the Jurassic Heather formation and maintain fairly uniform thickness. Feeder channels located to the west appear to be the primary mechanism of control in the distribution of sand across the unit. The location of these channels on the East Shetland platform is believed to have transported the main sand deposits to the west with Rhum receiving deposits under a depletive flow regime from west to east. The reservoir in Rhum consists of a primary unit identified as the Upper Main Reservoir (UMR) which contains 88% of the hydrocarbon volume in the field. This unit is further subdivided into three sub-units identified as UMR1, UMR2, and UMR3. Located below the UMR is the Lower Main Reservoir (LMR). These two units are present across the entire field and vary in thickness from 60 m at the crest of the reservoir to 200 m along the flanks. The units tend to be comprised of clean fine grain sands interbedded with shale. Above the UMR exists an additional unit identified as the Upper Reservoir (UR). This unit is generally thin and pinches out to the north of the field as demonstrated by the lack of sand in the 3/29a-5 well.

<u>Structure</u>

The Rhum field is structurally defined by two major north-south trending extensional faults, located at the southern tail of the North Viking Graben that form a terrace which is overlaid with the reservoir units. This graben is made up of a western dipping tilted fault block that forms the crest of the asymmetric anticlinal feature. This feature allowed hydrocarbons sourced from the Kimmeridge and Heather Claystones to be contained within a four-way dip closure capped by the Kimmeridge Clay Formation. Faulting within the reservoir units is dominated by NNE-SSW trending faults following the crest of the anticline. Movement in the field is described by BP as a westward prograding extensional fault system that primarily was in motion after deposition of the reservoir turbidities during the deposition of the Valhall Formation and Shetland D unit. Structural features in the field are described using 3-D seismic data tied to well control.

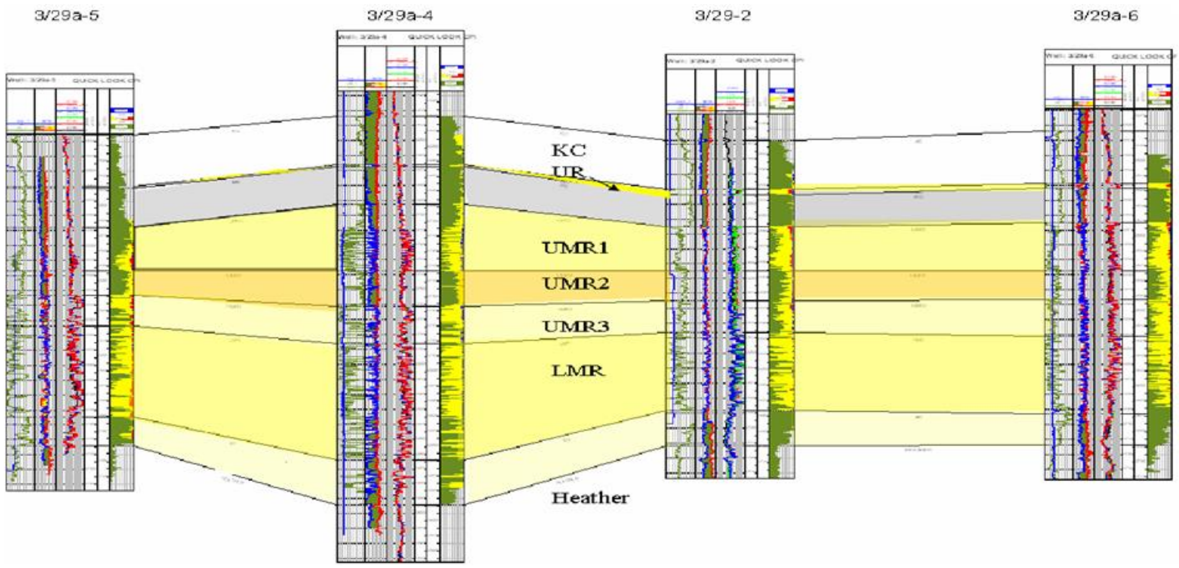
Fluid Contacts

Production of hydrocarbons in the Rhum field consists of gas and gas condensate from 3 production wells. The lower limit of hydrocarbons is defined by a gas-water contact observed in the 3/29a-4 well at a depth of -4745 m-ss. This contact is determined from well log data and is further verified by core and pressure data. RFT data also were used to demonstrate the hydrocarbon column as having one common pressure gradient that is in hydraulic communication across all of the units. Faulting in the field is not believed to compartmentalize the main area into isolated units based on well test data as well as supplemental coherency extraction from the reprocessed 3-D seismic survey. These faults often exhibit throws of 50 m to 150 m with only small portions fully offsetting the reservoir units.

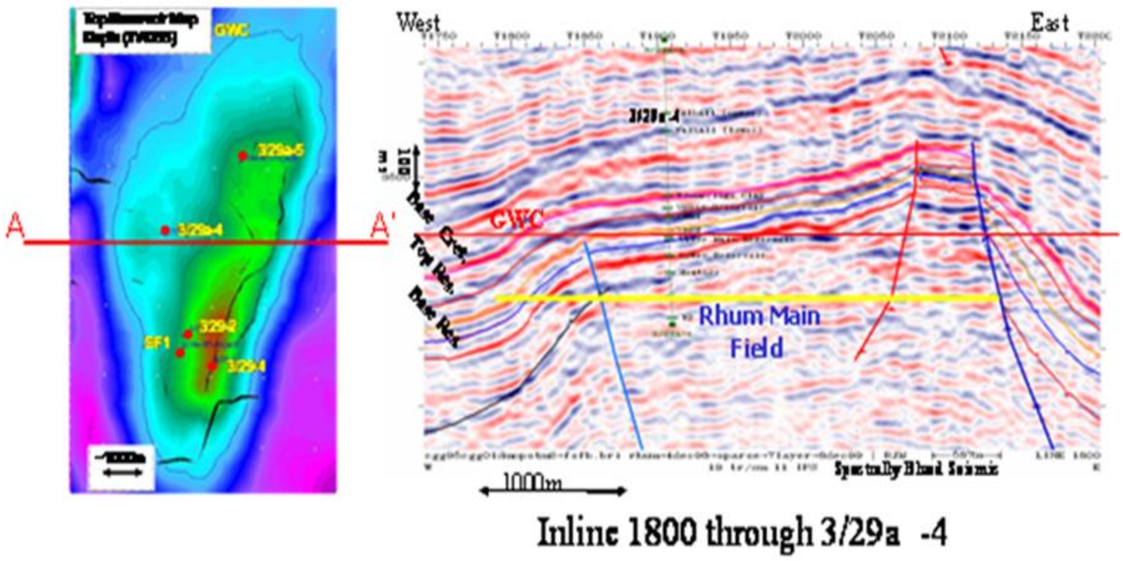
Petrophysical Properties

The Rhum field is primarily made up of generally clean fine grain sandstones with quartz-cement. Analyses of well log and core data show porosity distribution in the 4-16% range. In Rhum, the collection of core data has allowed for the measurement of air-brine capillary pressure to create a capillary pressure saturation model. This is particularly beneficial in the modeling of the reservoir for simulation purposes, since the water saturation values can be reliably correlated to the height above the free water level. Special core analysis shows irreducible water saturation to be approximately 14%. Permeability in the reservoir ranges from 45 md to a maximum of 600 md.

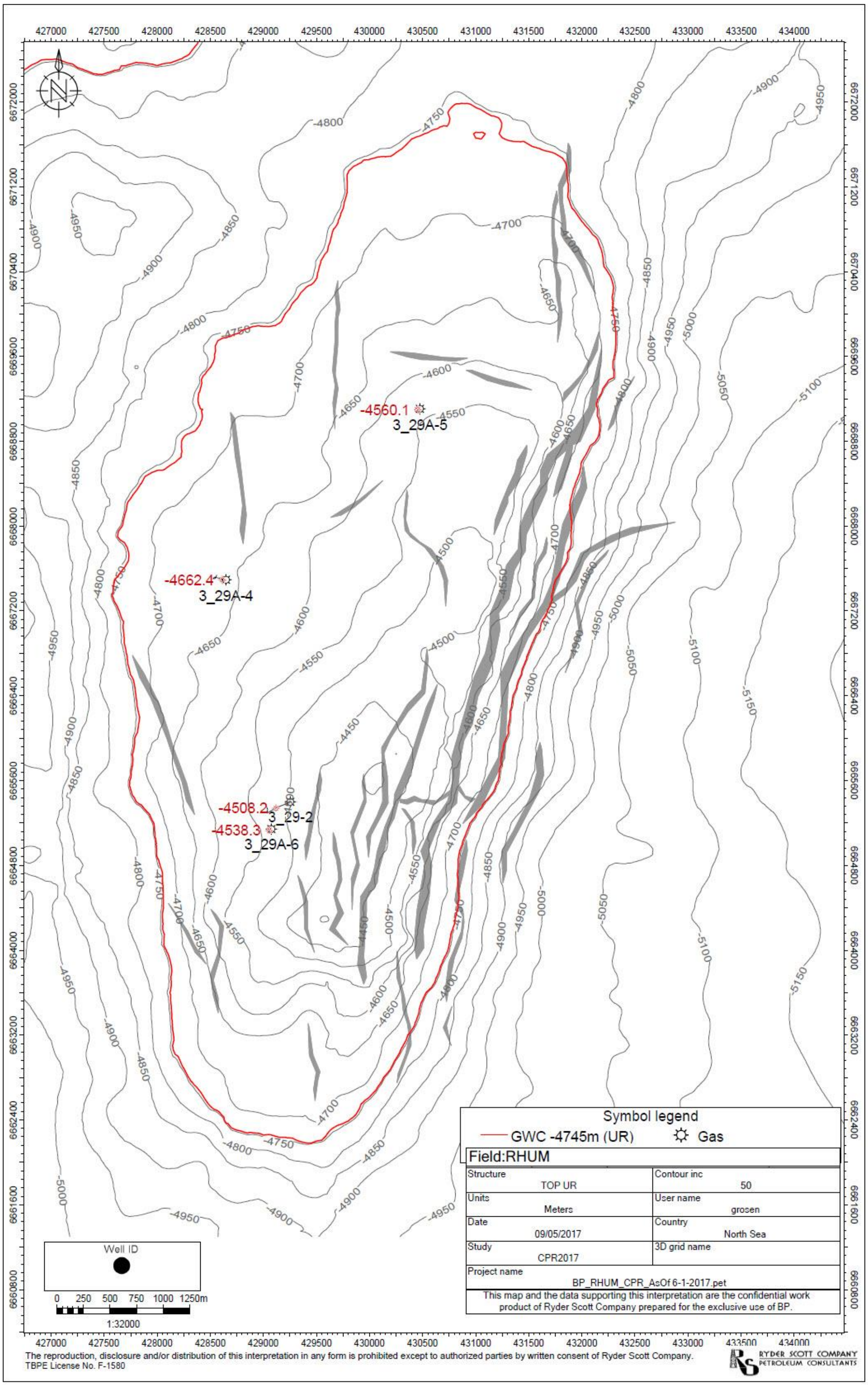
The figures below show west-east well log and seismic cross-sections. Also below is a structure map of the Rhum field.



Rhum West-East Cross-Section (BP)



Rhum West-East Cross-Section (BP)



Structure - Top of UR (RSC)

4.3.1.2 Current Field Development and Future Plans

The Rhum field was first discovered in 1977 with the drilling of the 3/29a-2 well. Prior to this well the 3/29-1 well was drilled in 1973 along the crest of the reservoir but was abandoned due to the high pressures that were encountered. The field was sanctioned for development in 2003 after the successful flow test of the 3/29a-4 exploration well, which was later converted into a production well. First gas production occurred in 2005 from wells 3/29a-4 (R-1) and 3/29a-5 (R-2). A third well, the 3/29a-6 (R-3), has not produced due to hydrate problems. As a consequence of the imposed European Union sanctions on the Iranian Oil Company, the field was shut-in from November 2010 to October 2014. Approval was gained to re-start production, and in the future BP expects to be allowed to produce unhindered from this issue.

For the future forecast BP presented two additional projects in their exploitation plan. The first one is a stimulation workover to be performed in well R-2 in September of 2017. The well has shown a continuous drop in production since July 2016. A previous study done pertaining to the produced water from R-2 identified the risk of calcium carbonate scale deposition once the flowing bottomhole pressure in the wellbore begins to drop. Any scale build up at the subsurface level has to be treated with well intervention. Ryder Scott estimated 1P, 2P and 3P volumes for this workover. A second workover related with a recompletion of the R-3 well is proposed by BP. A new completion is planned to be installed in the R-3 well during the first semester of 2018. The new completion should alleviate the hydrate formation problem in this well. Ryder Scott estimated volumes for the 1P, 2P and 3P scenarios for this recompletion. Both projects have been approved and have commitment for execution.

4.3.1.3 Reserves Estimation Methodology

The reserves in the Rhum field are based upon the estimation of the original gas-in-place for each of the 5 identified reservoirs (UR, UMR1, UMR2, UMR3, and LMR). Gross volumes were calculated for each reservoir for the aerial extent within the gas-water contact (-4745 m). Net-to-Gross values calculated at the well locations were spatially distributed across the reservoir to derive the net volumes. While a current fault model was not available, years of production data indicate that the N-S trending faults are not sealing and provide little impedance to the flow of gas through the reservoir.

Porosity values were calculated at the well locations for each reservoir and used to determine weighted averages representative of the formation. Capillary pressure models were used to calculate Sw throughout each well and the weighted averages were used to determine representative values of each reservoir.

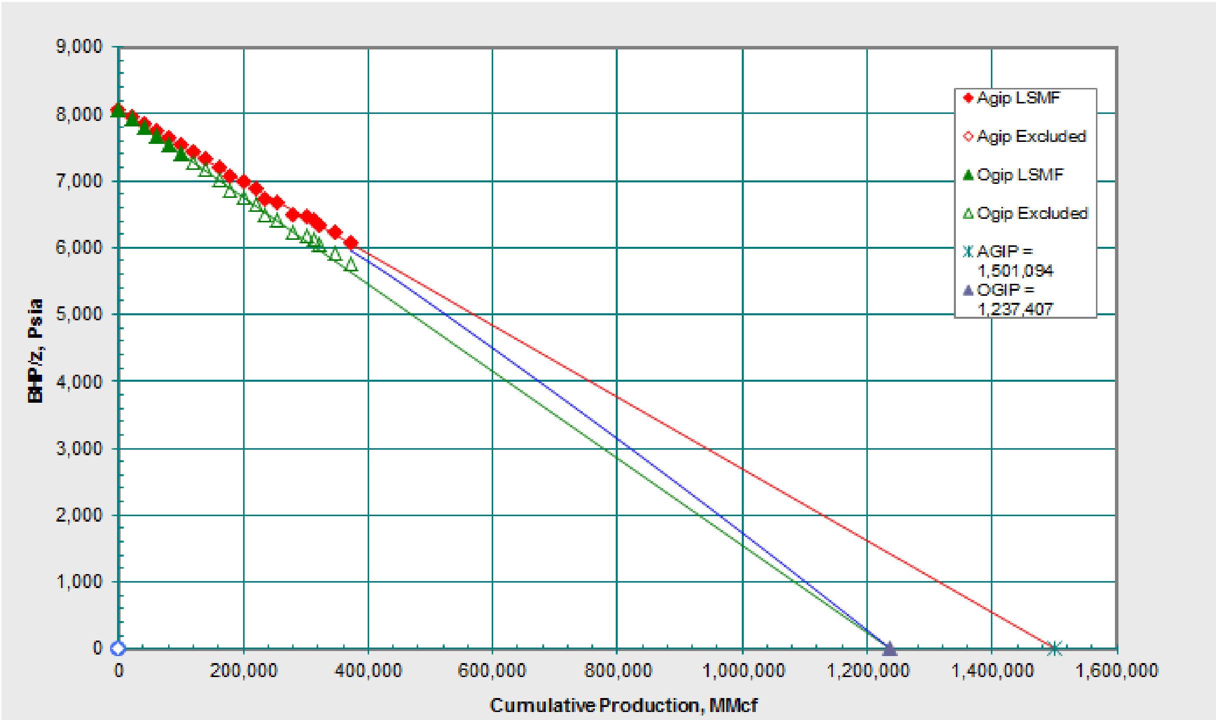
Projections were made to 2032 when the full 3P production is forecasted to be recovered. The reserves projections were terminated at YE2026 which was determined to be the economic limit for the 2P category of the Bruce platform complex (BKR), which includes the Bruce, Keith and Rhum fields. Also of note, the Rhum field gas contains CO_2 of approximately 6%, which alone would exceed the limits allowed into the Frigg Transportation System (FTS) and further downstream to the UK national grid (UTS). However, this gas is blended with Bruce field gas and other gas through an agreement with Statoil to supply blended gas through the Vesterland system. BP has indicated that there will be a code change at St. Fergus terminal sometime during the second part of the year 2017. This code change will involve raising the CO_2 percentage concentration at which gas can be delivered from the terminal. This will allow Rhum to flow unconstrained from 2018 forward. Additionally, BP has indicated that significant gas supply from another two fields in 2018 through the new SIRGE system, will allow Rhum to produce without CO_2 restrictions. These blending issues were reviewed with BP assuring Ryder

Scott that, while we cannot verify the other third party volumes, there is reasonable certainty that the code will be changed.

For the purpose of the evaluation of the reserves in this study Ryder Scott used a combination of the volumetric and performance methods such as the Material Balance evaluation, in order to estimate recoverable volumes in the 1P, 2P and 3P category. For the 1P scenario Ryder Scott used its own geological mapping which indicated a smaller volume than the one estimated by the Material Balance plot of P/Z vs. cumulative production. A summary of the volumetric results obtained from our geologic model is shown below:

Variable	UR	UMR1	UMR2	UMR3	LMR
Area, acres	7,247	5,988	4,773	4,651	4,045
Porosity, %	14.42%	11.68%	8.49%	8.34%	7.30%
Water Saturation, %	13.14%	16.16%	18.73%	14.84%	15.76%
OGIP, MMSCF	84,752	384,900	23,539	169,566	337,118

The total estimated OGIP volume derived from this volumetric analysis was 999,875 MMSCF. Ryder Scott also verified that there is communication among all these reservoirs by performing a Material Balance analysis using the produced fluids and available pressure data in the field. The production is predominately from the 2 wells down dip of R-3, the R-1 and R-2. Little water production has been measured from these wells. Current water to gas ratios oscillate between 1.3 to 1.4 bbls/ MMSCF. The pressure measurements are from the shut in well R-3 which has a gauge at the bottom wellbore at the reservoir level of 4044 m-ss. With the combination of the two sets of information, a P/Z vs. cumulative production plot was created and is illustrated below:



The corrected wet OGIP for an abnormal pressure gradient was estimated at 1,237 bcf. This value translated to a separator level volume of OGIP of 1,228 bcf. This volume was selected for the 2P scenario. An upside case of the P/Z plot shown above was evaluated indicating a volume of 1,327 bcf of gas for the 3P scenario. As of May 2017 the cumulative recovery factor was calculated at 37%. BP provided a numerical simulation model with estimated recovery factors of approximately 75%. Ryder Scott reviewed the recovery factors results from this model and found it within an acceptable range. Ryder Scott estimated recovery factor of 70%, 74% and 78% for the 1P, 2P and 3P scenarios respectively and used these values for our forecast predictions. Nodal analysis was performed with the deliverability data provided by BP and estimated unconstrained gas rates for the remainder of the life of the field.

In the forecast of all 1P, 2P and 3P scenarios the incremental volumes for the R-2 scale stimulation in 2017 and the R-3 recompletion in 2018 were added. These volumes were classified in the undeveloped category. These volumes were estimated by the combination of the volumetric and performance methods. The simulation study provided by BP was reviewed and we found their forecasts for these two projects to be within acceptable ranges.

	Units	**1P**	**2P**	**3P**
GIP	BCF	1,000	1,228	1,327
RF %	%	70%	74%	78%
EUR	BCF	700	909	1,035
Method		Volumetrics	Material Balance	Material Balance

The recovery factors presented in the following sections were calculated using the CoP of 2023 for 1P and 2026 for the 2P scenarios and therefore differ slightly from the ones estimated technically in this section.

4.3.1.4 Reserves Summary

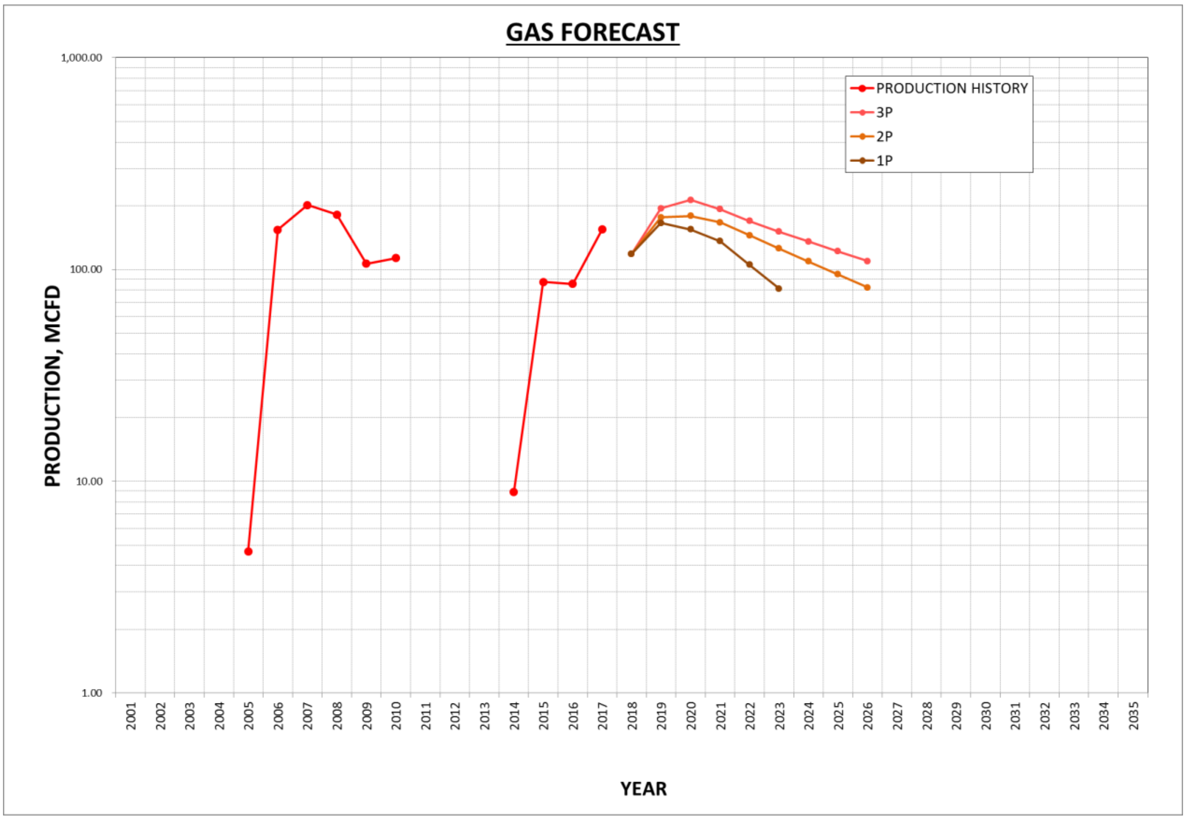
The table below shows the Gross reserves for the Rhum field.

RHUM FIELD - GROSS RESERVES AS OF JUNE 1, 2017									
		PROVED (1P) Reserves							
		Developed			Total	Cumulative	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	Proved	Production	Recovery	Factor
OIL/COND	– MBarrels	1,136	0	553	1,689			
PLANT PRODUCTS	– MBarrels	1,006	0	486	1,493			
GAS	– MMCF	179,736	0	86,873	266,608	368,315	651,644	65%
FUEL GAS	– MMCF	11,215	0	5,506	16,721			
Total	– MMBOE	35.1	0.0	17.0	52.0			
		Proved + Probable (2P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	2P	Probable	Recovery	Factor
OIL/COND	– MBarrels	1,723	0	848	2,571	883		
PLANT PRODUCTS	– MBarrels	1,580	0	776	2,356	863		
GAS	– MMCF	282,413	0	138,616	421,028	154,420	814,288	66%
FUEL GAS	– MMCF	16,534	0	8,411	24,944	8,224		
Total	– MMBOE	54.8	0.0	27.0	81.8	28.4		
		Proved + Probable+Possible (3P) Reserves						
		Developed			Total	Total	Ultimate	Recovery
		Producing	Non-Producing	Undeveloped	3P	Possible	Recovery	Factor
OIL/COND	– MBarrels	1,988	0	979	2,967	395		
PLANT PRODUCTS	– MBarrels	1,900	0	933	2,833	478		
GAS	– MMCF	339,840	0	166,901	506,741	85,712	900,000	68%
FUEL GAS	– MMCF	16,534	0	8,411	24,944	0		
Total	– MMBOE	65.3	0.0	32.1	97.5	15.7		
Used CoP of YE2023 for 1P and YE2026 for 2P. Note that gas above needs to be reduced by 1% shrinkage factor before sales.								

Table of Rhum Field Gross Reserves as of June 1, 2017

4.3.1.5 Reserves Forecast

Below is a graph showing the production history and forecasted production profile for the Rhum field 1P, 2P and 3P reserves. After returning to production in late 2014 and new gas becoming available in late 2015 for CO_2 blending, Rhum production is expected to increase to previous levels during 2018. .



Plot of Rhum Gas Production History and Forecast

A table of the 1P production profile is shown below. Ryder Scott estimated the 1P CoP at year-end 2023 for this field based on economics. The volumes from 2023 until the end of 2026 are considered to be 2P reserves. The CoP for the 2P scenario was estimated at 2026. BP has a 50% ownership in this field.

	RHUM FIELD			
1P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	168	135	24,052	1,319
2018	382	326	58,109	2,439
2019	344	303	54,060	2,400
2020	294	265	47,313	2,573
2021	218	200	35,786	2,642
2022	162	151	27,029	2,664
2023	121	113	20,260	2,683
2024	90	84	15,058	2,713
2025	66	61	10,945	2,744
2026	49	44	7,810	2,767
2027	28	19	3,423	2,808
2028	-	-	-	-
2029	-	-	-	-
2030	-	-	-	-
2031	-	-	-	-
2032	-	-	-	-
1P TO YE2023	1,689	1,493	266,608	16,721
CUM (06/2017)			368,315	
ULTIMATE TO YE2023			651,644	
RS estimated CoP at 2023. Note that gas above needs to be reduced by 1% shrinkage factor before sales. BP has a 50% Working Interest in this field.				

A table of the 2P production profile is shown below. Ryder Scott estimated the 2P CoP at year-end 2026 for this field based on economics. BP has assured Ryder Scott that it does not expect any material Capex expenditure (over and above normal operating expenditure) to maintain production until 2026. Production from 2027 to 2032 is categorized as 2C resources.

	RHUM FIELD			
2P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	168	135	24,052	1,319
2018	406	347	62,009	2,439
2019	399	353	62,965	2,400
2020	361	328	58,543	2,573
2021	303	281	50,272	2,642
2022	255	242	43,283	2,664
2023	215	208	37,214	2,683
2024	182	179	32,020	2,713
2025	152	153	27,327	2,744
2026	128	130	23,344	2,767
2027	109	111	19,865	2,808
2028	95	94	16,878	2,860
2029	79	79	14,206	2,883
2030	67	67	11,958	2,881
2031	56	56	10,004	2,881
2032	31	25	4,527	2,889
2P TO YE2026	2,571	2,356	421,028	24,944
CUM (06/2017)			368,315	
ULTIMATE YE2026			814,288	
RS estimated CoP at 2026. Note that gas above needs to be reduced by 1% shrinkage factor before sales. BP has a 50% Working Interest in this field.				

A table of the 3P production profile is shown below. Ryder Scott estimated the 3P CoP at year-end 2026 for this field based on economics.

	RHUM FIELD			
3P - SPE-PRMS	ESTIMATED GROSS (8/8ths) PRODUCTION FORECAST AS OF JUNE 1, 2017			
YEAR	OIL/COND	PLT PRODUCTS	GAS	FUEL GAS
	MBBL	MBBL	MMCF	MMCF
2017	168	135	24,052	1,319
2018	440	384	68,481	2,439
2019	462	421	75,285	2,400
2020	408	380	67,959	2,573
2021	346	331	59,260	2,642
2022	298	293	52,513	2,664
2023	258	261	46,799	2,683
2024	224	234	41,913	2,713
2025	194	208	37,265	2,744
2026	168	185	33,214	2,767
2027	146	164	29,479	2,808
2028	131	150	26,823	2,860
2029	107	122	21,941	2,883
2030	87	100	17,942	2,881
2031	71	81	14,585	2,881
2032	39	39	7,019	2,889
3P TO YE2026	2,967	2,833	506,741	24,944
CUM (06/2017)			368,315	
ULTIMATE YE2026			900,000	
RS estimated CoP at 2026. Note that gas above needs to be reduced by 1% shrinkage factor before sales. BP has a 50% Working Interest in this field.				

4.3.2 Contingent Resources Discussion

4.3.2.1 General Objective of Contingent Resource Projects

The descriptions of the structural and stratigraphic features of the reservoir areas where the resources are located in Rhum are described in the section associated with reserves. The general objectives of the contingent resources in Rhum field are primarily commercial and are associated with the economic feasibility of further development.

4.3.2.2 Resources Estimation Methodology

The only contingent resources projected for the Rhum field are the production volumes forecasted beyond the 2P CoP of 2026. These total volumes were based upon projected volumes from years 2027 to 2032.

4.3.2.3 Contingencies

Volumes attributed to the production period beyond the CoP are contingent upon conditions in the future which would result in economic production. Due to the age of the Rhum and associated Bruce facilities, extended production beyond the CoP may require facility upgrades.

4.3.2.4 Resources Summary

The table below shows the 2C Contingent Resource volumes projected for the Rhum field.

GROSS VOLUMES - RHUM FIELD (BP 50% WORKING INTEREST)						
	1C		2C		3C	
Project	MBBL	MMCF	MBBL	MMCF	MBBL	MMCF
VOLUMES ATTRIBUTED TO PERIOD BEYOND 2P CoP			436	77,438		
TOTALS			436	77,438		

Table of Rhum Field 2C Contingent Resources

5.0 Summary of Total Reserves and Contingent Resources

A summary of the total estimates of net reserves is presented below for the combined properties. Also shown below is our summary of the total 2C contingent resources for all the properties.

5.1 Summary of Net Reserves – SPE-PRMS Escalated Parameters

SPE-PRMS Escalated Parameters
Estimated Net Reserves and Contingent Resources Volumes
Attributable to Certain Interests in the Bruce, Keith and Rhum Fields
BP Exploration and Production
As of June 1, 2017

	Proved (1P)	Proved+ Probable (2P)	Proved+ Probable+Possible (3P)
Net Remaining Reserves			
Oil/Condensate – MBarrels	1,706	2,483	2,680
Plant Products – MBarrels	1,688	2,511	2,750
Sales Gas – MMCF	160,876	249,424	291,852
Fuel Gas – MMCF	10,132	14,834	14,834

5.2 Summary of Contingent Resources (2C) – SPE-PRMS Escalated Parameters

A summary of our estimated total net 2C Contingent Resources is shown below.

	Contingent Resources (2C)
Net Contingent Resources	
Oil/Condensate – MBarrels	223
Gas – MMCF	38,801

Liquid hydrocarbons are expressed in thousands of standard 42 U.S. gallon barrels (MBarrels). All gas volumes are reported on an “as sold” basis expressed in millions of cubic feet (MMCF) at the official temperature and pressure base of the areas in which the gas reserves are located. Those gas volumes that are consumed as fuel in operations are also reported separately herein.

6.0 Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to BP, Serica and Peel Hunt. Neither we nor any of our employees have any financial interest in the subject properties, and neither the employment to do this work nor the compensation is contingent on our estimates of reserves and resources for the properties which were reviewed. Ryder Scott is professionally qualified and a member in good standing of an appropriate recognized professional association under the AIM Rules with at least five years relevant experience in the estimation, assessment and evaluation of oil and gas assets

The results of this study, presented herein, are based on technical analyses conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves and resource information discussed in this report, are included below.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
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Guale Ramirez, P.E.
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Executive Vice President

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GR-MAB (DCR)/pl

7.0 Professional Qualifications of Primary Technical Person

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mario A. Ballesteros was the primary technical person responsible for overseeing the independent estimation of reserves, future production and income to render the audit conclusions of the report presented herein.

Mr. Ballesteros, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President and also serves as an Engineering Group Leader responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Ballesteros served in a number of engineering positions with Chevron. For more information regarding Mr. Ballesteros geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Ballesteros earned a Bachelor of Science degree in Mechanical Engineering in 1991 and a Masters of Petroleum Engineering degree in 1993 from the University of Tulsa. He also earned a Masters in Finance in 2000 from the Meta University in Colombia. He is a registered Professional Engineer in the State of Texas.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of fifteen hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Ballesteros fulfills. Mr. Ballesteros has attended formalized training and conferences including dedicated to the subject of the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register.

Based on his educational background, professional training and more than 20 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Ballesteros has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information” promulgated by the Society of Petroleum Engineers as of February 19, 2007..

8.0 Petroleum Reserves and Resources Classification and Definitions

As Adapted From:
2007 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)[1]
Sponsored by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM CONGRESS (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
AND
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

Reserve and resource classification systems are intended to allow the evaluator to follow the progression of changes in the exploration and production life cycle of a reservoir, field, or project that arise as a result of obtaining more technical information or as a result of a change in the economic status. Most systems incorporate terminology to describe the progression of a project from the delineation of an initial prospect, to the confirmation of the prospect through exploration drilling, onto the appraisal and development phase, and finally from initial production through depletion. These reserve and resource definitions thus provide the decision making framework to manage risk and uncertainty through the classification and categorization of the recoverable hydrocarbon volumes.

The term “resources” is generally applied to “all quantities of petroleum (recoverable and unrecoverable) naturally occurring on or within the Earth’s crust, discovered and undiscovered, plus those quantities already produced”.

The term “reserves” is a subset of resources generally applied to the discovered “quantities of petroleum anticipated to be commercially recoverable from known accumulations from a given date forward under defined conditions”.

All reserve and resource 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. Estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change.

Estimation of reserves and resources is done under conditions of uncertainty. The method of estimation is called deterministic if a single best estimate of reserves and resources 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. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves and/or resource classifications.

Reserves and resources 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.

Reserves and resources may be attributed to either conventional or unconventional petroleum accumulations under the SPE-PRMS. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale. Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale. The SPE-PRMS acknowledges unconventional petroleum accumulations as reserves and resources regardless of their in-place characteristics, the extraction method applied, or the degree of processing required.

Reserves and resources do not include quantities of petroleum being held in inventory and may be reduced for usage, processing losses and/or non-hydrocarbons that must be removed prior to sale.

SPE-PRMS

In March 2007, the Society of Petroleum Engineers (SPE), World Petroleum Council (WPC), American Association of Petroleum Geologists (AAPG), and Society of Petroleum Evaluation Engineers (SPEE) jointly approved the "Petroleum Resources Management System" (SPE-PRMS). The SPE-PRMS consolidates, builds on, and replaces guidance previously contained in the 2000 "Petroleum Resources Classification and Definitions" and the 2001 "Guidelines for the Evaluation of Petroleum Reserves and Resources" publications.

Reference should be made to the full SPE-PRMS for the complete definitions and guidelines as the following definitions, descriptions and explanations rely wholly or in part on excerpts from the SPE-PRMS document (passages excerpted in their entirety from the SPE-PRMS document are denoted in italics herein). For convenience, Table 1: "Recoverable Resources Classes and Sub-Classes" from the SPE-PRMS has been reproduced in full and included as an attachment to this document.

The SPE-PRMS incorporates the petroleum initially-in-place as well as the recoverable and unrecoverable petroleum quantities into a common resource classification framework. *Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase.*

The SPE-PRMS defines the major resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum. The basic classification scheme requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial (Reserves) and sub-commercial projects (Contingent Resources) in known accumulations. Under this classification scheme, estimated recoverable quantities from accumulations that have yet to be discovered are termed Prospective Resources. Further, the SPE-PRMS includes all types of petroleum whether currently considered "conventional" or "unconventional".

Figure 1 shown at the end of this document is a graphical representation of the SPE, WPC, AAPG and SPEE resources classification system. The SPE-PRMS "classifies" reserves and resources according to project maturity and increasing chance of commerciality (vertical axis) and "categorizes" reserves and resources according to the *range of uncertainty* (horizontal axis) *of the estimated quantities potentially recoverable from an accumulation by a project*. The following definitions apply to the major subdivisions within the resources classification:

RESOURCES CLASSIFICATION (SPE-PRMS)

Recoverable petroleum resources as described herein may be classified into one of three principal resource classifications: Prospective Resources, Contingent Resources, or Reserves. The distinction between Prospective and Contingent Resources depends on whether or not there exists one or more wells and other data indicating the potential for moveable hydrocarbons (e.g. the discovery status). Discovered petroleum resources may be classified as either Contingent Resources or as Reserves depending on the chance that if a project is implemented it will reach commercial producing status (e.g. chance of commerciality). The distinction between various "classifications" of Resources and Reserves relates to their discovery status and increasing chance of commerciality as described herein.

The SPE-PRMS Section 1.1 and Appendix A define the following terms:

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, as of 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 not all of the 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.

Given the aforementioned constraints, a portion of the Petroleum-Initially-in-Place may need to be classified as Unrecoverable.

DISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Discovered Petroleum-Initially-in-Place is that quantity of petroleum which is estimated, as of a given date, to be contained in known accumulations prior to production.

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.

KNOWN ACCUMULATION

The SPE-PRMS defines an accumulation as *an individual body of petroleum-in-place*. For an accumulation to be considered as "known", it must have been discovered. A discovery is defined as *one petroleum accumulation or several petroleum accumulations collectively, which have been penetrated by one or several exploratory wells which have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons*. The SPE-PRMS states in this context, *"significant" implies that there is evidence of a sufficient quantity of* *petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery.* Known accumulations may contain Reserves and/or Contingent Resources.

RESERVES

Reserves are defined as those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy the following criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied.

Reserves are categorized in *accordance with the level of certainty associated with the estimates* (horizontal axis shown in Figure 1) *and may be further sub-classified based on project maturity and/or characterized by development and production status* (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

ADDITIONAL TERMS USED IN RESERVES EVALUATIONS (SPE-PRMS DEFINITIONS)

The SPE-PRMS Sections 2.3, 2.3.4, 2.4 and Appendix A define the following terms as follows:

Improved recovery. *Improved Recovery is the extraction of additional petroleum, beyond Primary Recovery, from naturally occurring reservoirs by supplementing the natural forces in the reservoir. It includes waterflooding and gas injection for pressure maintenance, secondary processes, tertiary processes and any other means of supplementing natural reservoir recovery processes. Improved recovery also includes thermal and chemical processes to improve the in-situ mobility of viscous forms of petroleum. (Also called Enhanced Recovery.)*

Improved recovery projects must meet the same Reserves commerciality criteria as primary recovery projects. There should be an expectation that the project will be economic and that the entity has committed to implement the project in a reasonable time frame (generally within 5 years; further delays should be clearly justified). If there is significant project risk, forecast incremental recoveries may be similarly categorized but should be classified as Contingent Resources.

The judgment on commerciality is based on pilot testing within the subject reservoir or by comparison to a reservoir with analogous rock and fluid properties and where a similar established improved recovery project has been successfully applied.

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favorable 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.

Similar to improved recovery projects applied to conventional reservoirs, successful pilots or operating projects in the subject reservoir or successful projects in analogous reservoirs may be required to establish a distribution of recovery efficiencies for non-conventional accumulations. Such pilot projects may evaluate both the extraction efficiency and the efficiency of unconventional processing facilities to derive sales products prior to custody transfer.

These incremental recoveries in commercial projects are categorized into Proved, Probable, and Possible Reserves based on certainty derived from engineering analysis and analogous applications in similar reservoirs.

Commercial. *When a project is commercial, this implies that the essential social, environmental and economic conditions are met, including political, legal, regulatory and contractual conditions. In addition, a project is commercial if the degree of commitment is such that the accumulation is expected to be developed and placed on production within a reasonable time frame. While 5 years is recommended as a benchmark, a longer time frame could be applied where for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.*

PROVED RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Table 3 define proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs under defined economic conditions, operating methods, and government regulations. 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.*

The area of the reservoir considered as Proved includes:

(1) the area delineated by drilling and defined by fluid contacts, if any, and

(2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines", Chapter 8).

Reserves in undeveloped locations may be classified as Proved provided that:

- *The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive.*

- *Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with the drilled Proved locations.*

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

UNPROVED RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Appendix A define unproved oil and gas reserves as follows:

Unproved oil and gas reserves*. Unproved Reserves are based on geoscience and/or engineering data similar to that used in estimates of Proved Reserves, but technical or other uncertainties preclude such reserves being classified as Proved. Unproved Reserves may be further categorized as Probable Reserves or Possible Reserves. Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.*

PROBABLE RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Table 3 define probable oil and gas reserves as follows:

Probable oil and gas reserves*. Probable Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.*

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

POSSIBLE RESERVES (SPE-PRMS DEFINITIONS)

The SPE-PRMS Section 2.2.2 and Table 3 define possible oil and gas reserves as follows:

Possible oil and gas reserves*. Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.*

Possible Reserves may be assigned to areas of a reservoir adjacent to Probable Reserves where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.

CONTINGENT RESOURCES

Contingent Resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet *considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there is currently no viable market, or where commercial recovery is dependent on the development of new technology, or where evaluation of the accumulation is insufficient to assess commerciality.*

Contingent Resources are categorized according to the range of technical uncertainty associated with the estimates (horizontal axis shown in Figure 1) may be further sub-classified based on project maturity and/or characterized by their economic status (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

UNDISCOVERED PETROLEUM-INITIALLY-IN-PLACE

Undiscovered Petroleum-Initially-in-Place is that quantity of petroleum which is estimated, as of 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, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future projects. Prospective Resources have both an associated chance of discovery and a chance of development.

Prospective Resources are categorized in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be further sub-classified based on project maturity (Refer to Figure 2 at the end of this document). Reference should be made to the full SPE-PRMS for the complete definitions and guidelines.

UNRECOVERABLE

Unrecoverable is a term that refers to that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

ADDITIONAL TERMS USED IN RESOURCES CLASSIFICATION (SPE-PRMS)

CHANCE OF COMMERCIALITY

The SPE-PRMS Section 2.1, Table 1 and Appendix A define the following terms relating to commerciality:

The “Chance of Commerciality”, as denoted in the SPE-PRMS and as shown in Figure 1, *is the chance that the project will be developed and reach commercial producing status*.

The chance of commerciality is determined by the probability of a discrete event occurring. In the context of the SPE-PRMS, the discrete event is comprised of one of several conditions, as noted below, which impact the project's commercial viability.

The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities. Commerciality is not solely determined based on the economic status of a project which refers to the situation where the income from an operation exceeds the expenses involved in, or attributable to, that operation. Conditions as noted in the SPE-PRMS include *technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms and taxes.*

A development project *may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir. An accumulation or potential accumulation may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.*

COMMERCIALITY APPLIED TO RESERVES

Commerciality as applied to Reserves must be based upon all of the following criteria:

- *Evidence to support a reasonable timetable for development.*
- *A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.*
- *A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.*
- *Evidence that the necessary production and transportation facilities are available or can be made available.*
- *Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.*
- *High confidence in the commercial producibility of the reservoir.*

To be included in a Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming.

In general, quantities should not be classified as Reserves unless there is *evidence of firm intention that the accumulation will be developed and placed on production within a reasonable time frame.* In certain circumstances, reserves may be assigned even though development may not occur for some time. *A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project.* The SPE-PRMS recommends *five years as a benchmark, but notes that a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives.*

For a project to be included in a Reserves class *there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate* *that 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.*

COMMERCIALITY APPLIED TO CONTINGENT RESOURCES

Estimated recoverable quantities from known accumulations that are not yet considered mature enough for commercial development as denoted by meeting all of the aforementioned conditions should be classified as Contingent Resources.

Based on assumptions regarding future conditions and their impact on economic viability, projects currently classified as Contingent Resources may be broadly divided into two groups:

- ***Marginal Contingent Resources** are those quantities associated with technically feasible projects that are either currently economic or projected to be economic under reasonably forecasted improvements in commercial conditions but are not committed for development because of one or more contingencies.*

- ***Sub-Marginal Contingent Resource**s are those quantities associated with discoveries for which analysis indicates that technically feasible development projects would not be economic and/or other contingencies would not be satisfied under current or reasonable forecasted improvements in commercial conditions. These projects nonetheless should be retained in the inventory of discovered resources pending unforeseen major changes in commercial conditions.*

Those discovered in-place volumes for which a feasible development project cannot be defined using current or reasonably forecast improvements in technology are classified as Unrecoverable.

RESOURCES CATEGORIZATION (SPE-PRMS)

All estimates of the quantities of petroleum potentially recoverable from an accumulation classified as having Prospective or Contingent Resources or Reserves involve uncertainty. The relative degree of uncertainty may be conveyed by placing the estimated quantities into one of several “categories” as described herein.

The SPE-PRMS Section 2.2 and Appendix A define the following terms:

RANGE OF UNCERTAINTY

The Range of Uncertainty, as denoted in the SPE-PRMS and as shown in Figure 1, reflects a range of estimated quantities potentially recoverable from an accumulation by a project. *Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods.*

<u>DETERMINISTIC METHODS (SPE-PRMS)</u>

<u>RESERVES</u>

For reserves, the range of uncertainty can be reflected as discrete incremental quantities termed Proved, Probable and Possible or expressed in cumulative terms as 1P (Proved), 2P (Proved plus Probable), and 3P (Proved plus Probable plus Possible), respectively.

<u>CONTINGENT RESOURCES</u>

For Contingent Resources, the range of uncertainty is generally expressed in deterministic scenario (cumulative) terms as 1C, 2C, 3C, respectively or in terms of probability using probabilistic methods. While the SPE-PRMS categorization scheme does not specifically prohibit the use of discrete incremental quantities for Contingent Resources, the SPE-PRMS does not denote the terms to be applied to these discrete incremental quantities.

<u>PROSPECTIVE RESOURCES</u>

For Prospective Resources, the range of uncertainty is generally expressed in deterministic scenario (cumulative) terms as low, best and high estimates or in terms of probability using probabilistic methods. As in the case of Contingent Resources, the SPE-PRMS categorization scheme does not specifically denote terms to be applied to discrete incremental quantities for Prospective Resources.

<u>INCREMENTAL TERMS FOR CONTINGENT AND PROSPECTIVE RESOURCES (RYDER SCOTT)</u>

Should evaluators choose to characterize the range of uncertainty for Contingent Resources or Prospective Resources in discrete incremental quantities, they should denote such quantities as such and provide sufficient detail in their report to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of the recoverable quantities. For reports prepared by Ryder Scott Company (Ryder Scott), the range of uncertainty for discrete incremental quantities of Contingent Resources shall be termed 1C Incremental (1Ci), 2C Incremental (2Ci) and 3C Incremental (3Ci) and in the case of Prospective Resources shall be termed Low Estimate Incremental (LEi), Best Estimate Incremental (BEi) and High Estimate Incremental (HEi) where (i) denotes a specific incremental quantity.

<u>BEST ESTIMATE</u>

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the “best estimate” is considered the most realistic assessment of recoverable quantities. The term "best estimate" is used here as a generic expression for the estimate considered being closest to the quantity that will actually be recovered from the accumulation between the date of the estimate and the time of abandonment. In the case of reserves, the best estimate is generally considered to represent *the sum of Proved and Probable estimates (2P). It should be noted that under the incremental (risk-based) approach for Reserves, discrete estimates are made for the quantities in each category for Proved and Probable, and they should not be aggregated without due consideration of their associated risk.* In the case of Contingent Resources and Prospective Resources, the best estimate would be represented by the 2C and Best Estimate, respectively. 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.

PROBABILISTIC METHODS (SPE-PRMS)

If probabilistic methods are used, these estimated quantities should be based on methodologies analogous to those applicable to the definitions of Reserves, Contingent Resources and Prospective Resources; therefore, in general, the resulting probabilities should correspond to the deterministic terms as follows:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the 1P, 1C or Low Estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the 2P, 2C or Best Estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the 3P, 3C or High Estimate.

COMPARABILITY OF SIMILAR RESERVES AND RESOURCE CATEGORIES

As indicated in Figure 1, the 1C, 2C and 3C Contingent Resource estimates and the Low, Best and High Prospective Resource estimates of potentially recoverable volumes should reflect some comparability with the reserves categories of Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P), 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.*

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves.

AGGREGATION

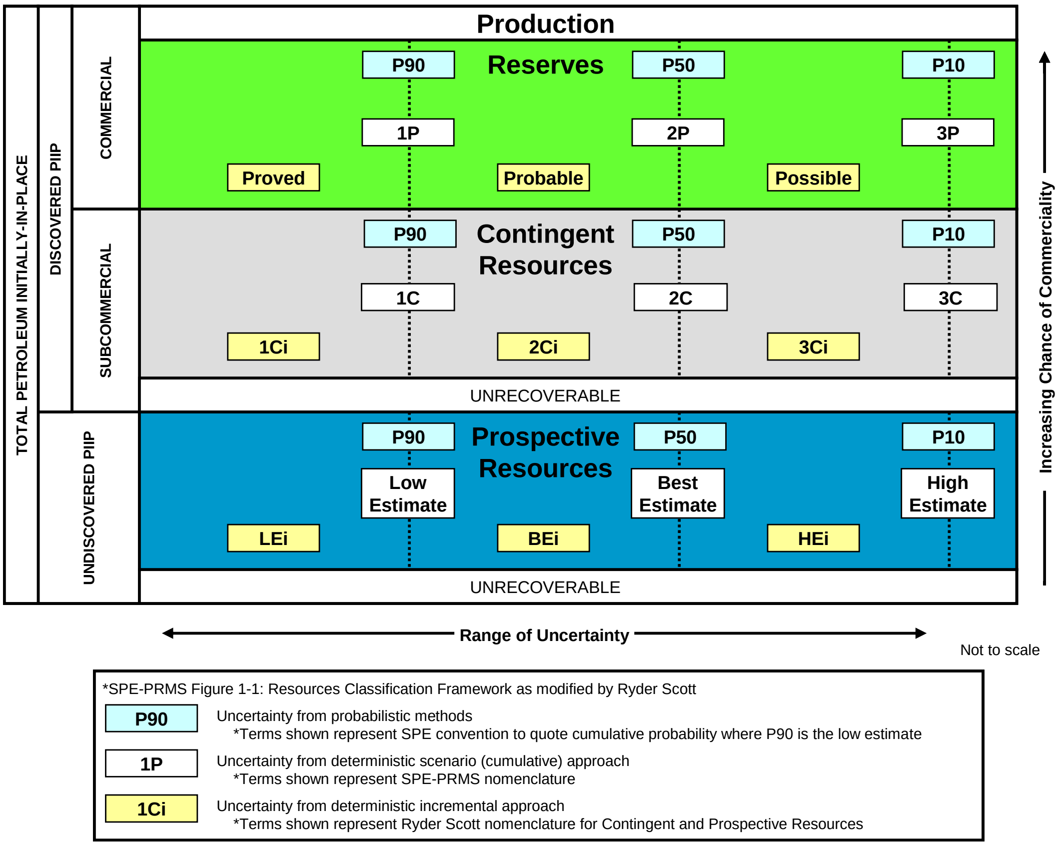
Petroleum quantities classified as Reserves, Contingent Resources or Prospective Resources should not be aggregated with each other without due consideration of the significant differences in the criteria associated with their classification. In particular, there may be a significant risk that accumulations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

RESOURCES CLASSIFICATION SYSTEM (SPE-PRMS)

GRAPHICAL REPRESENTATION

Figure 1 is a graphical representation of the SPE, WPC, AAPG, SPEE resources classification system. The horizontal axis represents the “Range of Uncertainty” in the estimated potentially recoverable volume for an accumulation by a project, whereas the vertical axis represents the “Chance of Commerciality”, that is, the chance that the project will be developed and reach commercial producing status.

Figure 1
SPE, WPC, AAPG, SPEE
RESOURCES CLASSIFICATION SYSTEM*



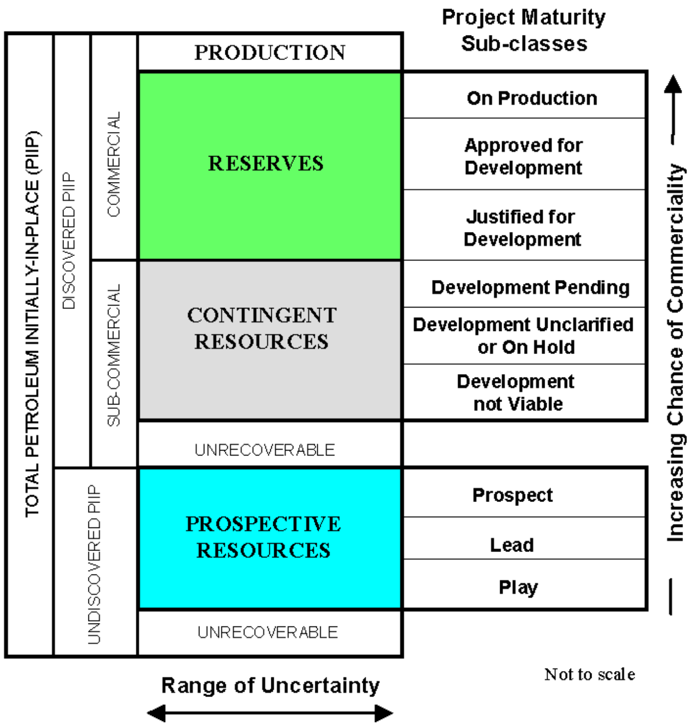
INCREMENTAL TERMS FOR CONTINGENT AND PROSPECTIVE RESOURCES AS DEFINED BY RYDER SCOTT

Should evaluators choose to characterize the range of uncertainty for Contingent Resources or Prospective Resources in discrete incremental quantities, they should denote such quantities as such and provide sufficient detail in their report to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of the recoverable quantities. For reports prepared by Ryder Scott Company (Ryder Scott), the range of uncertainty for discrete incremental quantities of Contingent Resources shall be termed 1C Incremental (1Ci), 2C Incremental (2Ci) and 3C Incremental (3Ci) and in the case of Prospective Resources shall be termed Low Estimate Incremental (LEi), Best Estimate Incremental (BEi) and High Estimate Incremental (HEi) where (i) denotes a specific incremental quantity.

RESOURCES CLASSIFICATION SYSTEM (SPE-PRMS)

GRAPHICAL REPRESENTATION

Figure 2
SPE, WPC, AAPG, SPEE
PROJECT MATURITY SUB-CLASSES



[1] Petroleum Resources Management System prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE); reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), March 2007.

Table 1: Recoverable Resources Classes and Sub-Classes

Class/ Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that 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
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project “chance of commerciality” can be said to be 100%. The project “decision gate” is the decision to initiate commercial production from the project.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity’s current or following year’s approved budget. The project “decision gate” is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

Class/ Sub-Class	Definition	Guidelines
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/ Sub-Class	Definition	Guidelines
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a re-classification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

[1]Petroleum Resources Management System, prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE); reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), March 2007

PETROLEUM RESERVES and RESOURCES STATUS DEFINITIONS and GUIDELINES

As Adapted From:
PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE),
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)

RESERVES

Reserves status categories define the development and producing status of wells and reservoirs. The SPE-PRMS Table 2 defines the reserves status categories as follows:

DEVELOPED RESERVES (SPE-PRMS DEFINITIONS)

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Developed Producing
Developed Producing Reserves are expected to be recovered from completion intervals that 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.

Developed Non-Producing
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-In
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 yet 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
Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES (SPE-PRMS DEFINITIONS)

Undeveloped Reserves are quantities expected to be recovered through future investments.

Undeveloped Reserves are expected to be recovered from:

(1) new wells on undrilled acreage in known accumulations;
(2) deepening existing wells to a different (but known) reservoir;
(3) infill wells that will increase recovery; or
(4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to
- *(a) recomplete an existing well; or*
- *(b) install production or transportation facilities for primary or improved recovery projects.*

CONTINGENT RESOURCES

Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent resource status categories may address the development and producing status of wells and reservoirs or may reflect the project maturity and/or be characterized by their economic status as noted in the SPE-PRMS Table 1 and Figure 2.

PROSPECTIVE RESOURCES

Prospective resources are by definition undeveloped as they are potentially recoverable from undiscovered accumulations. Prospective resource status categories reflect project maturity as noted in the SPE-PRMS Table 1 and Figure 2.

9.0 Cashflows

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - BP NORTH SEA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALES GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	GAS $/M
12-2017	24	565	482	34,254	1,926	226	192	15,661	878	53.15	29.93	4.96
12-2018	24	989	899	74,897	3,285	408	369	35,010	1,524	54.41	29.34	5.00
12-2019	22	827	807	68,953	3,285	345	333	32,312	1,518	55.71	29.86	5.10
12-2020	18	670	701	60,301	3,294	281	289	28,263	1,546	56.94	30.50	5.13
12-2021	15	483	539	45,961	3,285	204	222	21,504	1,552	58.24	31.32	5.14
12-2022	14	339	395	34,371	3,285	144	163	16,118	1,556	59.75	32.03	5.14
12-2023	11	229	288	25,560	3,285	99	120	12,009	1,558	61.09	32.61	5.24
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	4,102	4,112	344,298	21,645	1,706	1,688	160,876	10,132	56.22	30.46	5.09
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	4,102	4,112	344,298	21,645	1,706	1,688	160,876	10,132	56.22	30.46	5.09
CUMULATIVE		177,212	-	3,459,281	-				-			
ULTIMATE		181,314	4,112	3,803,578	21,645				10,132			

END	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				FGR AFTER PRODUCTION DISC CUM
MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	M$
12-2017	11,998	5,750	77,685	-	95,433	-	-	-	-	95,433
12-2018	22,184	10,817	175,094	-	208,095	-	-	-	-	208,095
12-2019	19,204	9,938	164,817	-	193,959	-	-	-	-	193,959
12-2020	16,020	8,823	144,989	-	169,831	-	-	-	-	169,831
12-2021	11,864	6,957	110,600	-	129,421	-	-	-	-	129,421
12-2022	8,613	5,231	82,788	-	96,632	-	-	-	-	96,632
12-2023	6,054	3,900	62,872	-	72,825	-	-	-	-	72,825
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	95,935	51,416	818,845	-	966,197	-	-	-	-	966,197
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	95,935	51,416	818,845	-	966,197	-	-	-	-	966,197

END	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	2,760	52,791	16,223	-	-	71,774	23,659	23,659	22,558	22,558	13,535
12-2018	3,846	74,602	13,147	-	-	91,595	116,500	140,159	100,980	123,538	74,123
12-2019	3,581	68,841	-	-	-	72,421	121,538	261,697	95,770	219,308	131,585
12-2020	3,305	64,099	-	-	-	67,404	102,428	364,124	73,374	292,682	175,609
12-2021	2,904	60,504	-	1,362	-	64,770	64,650	428,775	42,102	334,785	200,871
12-2022	2,537	59,390	-	1,286	-	63,212	33,420	462,195	19,785	354,570	212,742
12-2023	2,268	57,910	-	2,782	-	62,961	9,865	472,059	5,309	359,879	215,928
12-2024	-	-	-	10,640	-	10,640	(10,640)	461,420	(5,206)	354,674	212,804
12-2025	-	-	-	32,470	-	32,470	(32,470)	428,950	(14,443)	340,231	204,138
12-2026	-	-	-	35,107	-	35,107	(35,107)	393,842	(14,196)	326,035	195,621
12-2027	-	-	-	50,405	-	50,405	(50,405)	343,438	(18,529)	307,506	184,504
12-2028	-	-	-	70,228	-	70,228	(70,228)	273,210	(23,469)	284,037	170,422
12-2029	-	-	-	91,147	-	91,147	(91,147)	182,062	(27,691)	256,346	153,808
12-2030	-	-	-	52,426	-	52,426	(52,426)	129,636	(14,479)	241,867	145,120
12-2031	-	-	-	35,341	-	35,341	(35,341)	94,296	(8,873)	232,994	139,796
12-2032	-	-	-	14,085	-	14,085	(14,085)	80,211	(3,215)	229,779	137,867
12-2033	-	-	-	-	-	-	-	80,211	-	229,779	137,867
12-2034	-	-	-	-	-	-	-	80,211	-	229,779	137,867
S-TOT	21,201	438,136	29,370	397,279	-	885,986	80,211		229,779		
REM	-	-	-	-	-	-	-	80,211	-	229,779	137,867
TOTAL	21,201	438,136	29,370	397,279	-	885,986	80,211		229,779		

LIFE - 7 years

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RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALES GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	GAS $/M
12-2017	21	288	326	10,050	577	104	117	3,618	208	52.78	34.07	5.45
12-2018	20	455	543	16,839	802	164	196	6,062	289	53.56	34.57	5.53
12-2019	18	372	484	15,071	845	134	174	5,425	304	54.66	35.29	5.65
12-2020	14	294	420	13,174	721	106	151	4,743	259	55.75	35.99	5.68
12-2021	11	207	328	10,339	643	75	118	3,722	232	56.96	36.77	5.69
12-2022	10	136	236	7,481	621	49	85	2,693	224	58.33	37.66	5.69
12-2023	7	80	170	5,413	602	29	61	1,949	217	59.50	38.41	5.80
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	21	1,832	2,507	78,368	4,810	660	903	28,212	1,732	55.01	35.72	5.62
REM	-	-	-	-	-	-	-	-	-			
TOTAL	21	1,832	2,507	78,368	4,810	660	903	28,212	1,732	55.01	35.72	5.62
CUMULATIVE		164,814	-	3,066,209	-				-			
ULTIMATE		166,646	2,507	3,144,577	4,810				1,732			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	5,468	3,993	19,702	-	29,162	-	-	-	-	29,162
12-2018	8,770	6,762	33,545	-	49,077	-	-	-	-	49,077
12-2019	7,320	6,143	30,647	-	44,110	-	-	-	-	44,110
12-2020	5,907	5,447	26,946	-	38,299	-	-	-	-	38,299
12-2021	4,250	4,343	21,188	-	29,781	-	-	-	-	29,781
12-2022	2,853	3,204	15,323	-	21,380	-	-	-	-	21,380
12-2023	1,718	2,346	11,309	-	15,374	-	-	-	-	15,374
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	36,285	32,239	158,660	-	227,183	-	-	-	-	227,183
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	36,285	32,239	158,660	-	227,183	-	-	-	-	227,183

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	1,169	11,489	7,277	-	-	19,936	9,227	9,227	8,797	8,797	5,278
12-2018	1,885	15,121	10	-	-	17,017	32,060	41,287	27,789	36,587	21,952
12-2019	1,708	13,841	-	-	-	15,549	28,562	69,849	22,506	59,093	35,456
12-2020	1,515	12,514	-	-	-	14,029	24,269	94,118	17,385	76,478	45,887
12-2021	1,224	11,961	-	956	-	14,141	15,640	109,759	10,185	86,664	51,998
12-2022	932	11,770	-	870	-	13,572	7,808	117,566	4,622	91,286	54,772
12-2023	714	11,274	-	870	-	12,858	2,516	120,082	1,354	92,640	55,584
12-2024	-	-	-	8,688	-	8,688	(8,688)	111,393	(4,251)	88,389	53,033
12-2025	-	-	-	8,402	-	8,402	(8,402)	102,992	(3,737)	84,652	50,791
12-2026	-	-	-	28,328	-	28,328	(28,328)	74,664	(11,455)	73,197	43,918
12-2027	-	-	-	28,988	-	28,988	(28,988)	45,676	(10,656)	62,541	37,525
12-2028	-	-	-	51,669	-	51,669	(51,669)	(5,993)	(17,267)	45,274	27,165
12-2029	-	-	-	74,437	-	74,437	(74,437)	(80,430)	(22,614)	22,660	13,596
12-2030	-	-	-	35,311	-	35,311	(35,311)	(115,741)	(9,752)	12,908	7,745
12-2031	-	-	-	33,765	-	33,765	(33,765)	(149,506)	(8,478)	4,430	2,658
12-2032	-	-	-	12,984	-	12,984	(12,984)	(162,490)	(2,964)	1,467	880
12-2033	-	-	-	-	-	-	-	(162,490)	-	1,467	880
12-2034	-	-	-	-	-	-	-	(162,490)	-	1,467	880
S-TOT	9,147	87,970	7,287	285,269	-	389,673	(162,490)		1,467		
REM	-	-	-	-	-	-	-	(162,490)	-	1,467	880
TOTAL	9,147	87,970	7,287	285,269	-	389,673	(162,490)		1,467		

LIFE - 7 years

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BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	2	168	135	23,811	1,319	84	67.46	11,906	659	55.85	22.26	4.81
12-2018	3	382	326	57,528	2,439	191	163	28,764	1,220	56.67	22.72	4.89
12-2019	3	344	303	53,519	2,400	172	151	26,760	1,200	57.84	23.36	4.99
12-2020	3	294	265	46,840	2,573	147	132	23,420	1,287	58.99	23.99	5.02
12-2021	3	218	200	35,428	2,642	109	100	17,714	1,321	60.27	24.69	5.03
12-2022	3	162	151	26,758	2,664	81	76	13,379	1,332	61.72	25.49	5.02
12-2023	3	121	113	20,057	2,683	60	57	10,029	1,342	62.96	26.17	5.12
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	1,689	1,493	263,942	16,721	844	746	131,971	8,360	58.63	23.84	4.97
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	1,689	1,493	263,942	16,721	844	746	131,971	8,360	58.63	23.84	4.97
CUMULATIVE		2,448	-	368,315	-				-			
ULTIMATE		4,137	1,493	632,257	16,721				8,360			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	4,694	1,502	57,238	-	63,434	-	-	-	-	63,434
12-2018	10,815	3,698	140,527	-	155,040	-	-	-	-	155,040
12-2019	9,952	3,536	133,455	-	146,943	-	-	-	-	146,943
12-2020	8,660	3,176	117,476	-	129,312	-	-	-	-	129,312
12-2021	6,573	2,472	89,028	-	98,073	-	-	-	-	98,073
12-2022	5,011	1,927	67,205	-	74,143	-	-	-	-	74,143
12-2023	3,798	1,483	51,382	-	56,663	-	-	-	-	56,663
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	49,503	17,793	656,312	-	723,608	-	-	-	-	723,608
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	49,503	17,793	656,312	-	723,608	-	-	-	-	723,608

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	1,361	40,821	8,946	-	-	51,128	12,306	12,306	11,733	11,733	7,040
12-2018	1,635	58,781	13,137	-	-	73,553	81,487	93,793	70,632	82,365	49,419
12-2019	1,630	54,274	-	-	-	55,904	91,039	184,831	71,737	154,102	92,461
12-2020	1,607	50,986	-	-	-	52,594	76,719	261,550	54,958	209,059	125,436
12-2021	1,549	47,916	-	-	-	49,465	48,608	310,158	31,655	240,714	144,428
12-2022	1,511	47,223	-	-	-	48,734	25,409	335,566	15,043	255,757	153,454
12-2023	1,488	46,214	-	1,011	-	48,713	7,951	343,517	4,279	260,036	156,021
12-2024	-	-	-	1,032	-	1,032	(1,032)	342,485	(505)	259,531	155,719
12-2025	-	-	-	2,238	-	2,238	(2,238)	340,248	(995)	258,535	155,121
12-2026	-	-	-	2,280	-	2,280	(2,280)	337,968	(922)	257,614	154,568
12-2027	-	-	-	17,547	-	17,547	(17,547)	320,421	(6,450)	251,163	150,698
12-2028	-	-	-	18,133	-	18,133	(18,133)	302,288	(6,060)	245,104	147,062
12-2029	-	-	-	16,710	-	16,710	(16,710)	285,578	(5,077)	240,027	144,016
12-2030	-	-	-	17,115	-	17,115	(17,115)	268,463	(4,727)	235,300	141,180
12-2031	-	-	-	1,576	-	1,576	(1,576)	266,888	(396)	234,905	140,943
12-2032	-	-	-	1,101	-	1,101	(1,101)	265,786	(251)	234,653	140,792
12-2033	-	-	-	-	-	-	-	265,786	-	234,653	140,792
12-2034	-	-	-	-	-	-	-	265,786	-	234,653	140,792
S-TOT	10,782	346,215	22,083	78,742	-	457,822	265,786		234,653		
REM	-	-	-	-	-	-	-	265,786	-	234,653	140,792
TOTAL	10,782	346,215	22,083	78,742	-	457,822	265,786		234,653		

LIFE - 7 years

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DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	1	109	22	393	30	38	8	137	10	48.18	34.07	5.45
12-2018	1	153	30	530	43	53	10	185	15	48.89	34.57	5.53
12-2019	1	111	21	363	40	39	7	127	14	49.90	35.29	5.65
12-2020	1	82	16	286	-	29	6	100	-	50.89	35.99	5.68
12-2021	1	57	11	194	-	20	4	67	-	51.99	36.77	5.69
12-2022	1	40	8	131	-	14	3	46	-	53.25	37.66	5.69
12-2023	1	28	5	89	-	10	2	31	-	54.32	38.41	5.80
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	581	112	1,987	114	203	39	692	40	50.11	35.42	5.60
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	581	112	1,987	114	203	39	692	40	50.11	35.42	5.60
CUMULATIVE		9,950	-	24,757	-				-			
ULTIMATE		10,531	112	26,744	114				40			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	1,836	256	745	-	2,836	-	-	-	-	2,836
12-2018	2,599	357	1,022	-	3,978	-	-	-	-	3,978
12-2019	1,932	259	715	-	2,906	-	-	-	-	2,906
12-2020	1,453	200	567	-	2,220	-	-	-	-	2,220
12-2021	1,040	141	384	-	1,566	-	-	-	-	1,566
12-2022	749	100	261	-	1,110	-	-	-	-	1,110
12-2023	537	71	180	-	788	-	-	-	-	788
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	10,147	1,385	3,873	-	15,406	-	-	-	-	15,406
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	10,147	1,385	3,873	-	15,406	-	-	-	-	15,406

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	229	480	-	-	-	710	2,127	2,127	2,028	2,028	1,217
12-2018	326	699	-	-	-	1,026	2,953	5,079	2,559	4,587	2,752
12-2019	242	726	-	-	-	969	1,938	7,017	1,527	6,114	3,668
12-2020	182	598	-	-	-	781	1,440	8,456	1,031	7,145	4,287
12-2021	130	627	-	406	-	1,164	402	8,859	262	7,407	4,444
12-2022	93	397	-	415	-	906	204	9,062	121	7,527	4,516
12-2023	67	422	-	901	-	1,390	(602)	8,460	(324)	7,204	4,322
12-2024	-	-	-	920	-	920	(920)	7,541	(450)	6,754	4,052
12-2025	-	-	-	21,831	-	21,831	(21,831)	(14,290)	(9,710)	(2,957)	(1,774)
12-2026	-	-	-	4,500	-	4,500	(4,500)	(18,790)	(1,819)	(4,776)	(2,866)
12-2027	-	-	-	3,870	-	3,870	(3,870)	(22,659)	(1,422)	(6,199)	(3,719)
12-2028	-	-	-	426	-	426	(426)	(23,085)	(142)	(6,341)	(3,805)
12-2029	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
12-2030	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
12-2031	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
12-2032	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
12-2033	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
12-2034	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
S-TOT	1,272	3,951	-	33,268	-	38,491	(23,085)		(6,341)		
REM	-	-	-	-	-	-	-	(23,085)	-	(6,341)	(3,805)
TOTAL	1,272	3,951	-	33,268	-	38,491	(23,085)		(6,341)		

LIFE - 7 years

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RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - BP NORTH SEA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	24	630	540	35,997	1,926	249	213	16,288	878	53.11	30.33	4.98
12-2018	24	1,268	1,188	86,991	3,285	511	476	39,905	1,524	54.31	30.25	5.04
12-2019	22	1,067	1,061	84,049	3,285	439	431	38,980	1,518	55.69	30.41	5.12
12-2020	18	869	911	75,957	3,294	362	374	35,455	1,546	56.98	30.73	5.14
12-2021	15	657	726	63,560	3,285	278	300	29,847	1,552	58.40	31.11	5.14
12-2022	14	495	572	53,139	3,285	214	240	25,127	1,556	60.03	31.51	5.12
12-2023	11	358	433	43,916	3,285	159	185	20,966	1,558	61.52	31.53	5.21
12-2024	7	262	294	35,281	3,294	119	131	17,139	1,566	63.06	30.75	5.28
12-2025	5	172	188	28,167	3,285	83	89	13,927	1,567	65.20	29.33	5.35
12-2026	5	140	151	23,759	3,285	68	73	11,789	1,570	66.59	29.55	5.45
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	5,916	6,063	530,815	31,509	2,483	2,511	249,424	14,834	57.36	30.65	5.15
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	5,916	6,063	530,815	31,509	2,483	2,511	249,424	14,834	57.36	30.65	5.15
CUMULATIVE		177,212	-	3,459,281	-				-			
ULTIMATE		183,128	6,063	3,990,096	31,509				14,834			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	13,221	6,456	81,100	-	100,777	-	-	-	-	100,777
12-2018	27,776	14,401	200,927	-	243,104	-	-	-	-	243,104
12-2019	24,435	13,109	199,572	-	237,116	-	-	-	-	237,116
12-2020	20,647	11,482	182,153	-	214,281	-	-	-	-	214,281
12-2021	16,246	9,349	153,315	-	178,909	-	-	-	-	178,909
12-2022	12,819	7,551	128,684	-	149,054	-	-	-	-	149,054
12-2023	9,756	5,831	109,153	-	124,740	-	-	-	-	124,740
12-2024	7,532	4,019	90,460	-	102,011	-	-	-	-	102,011
12-2025	5,429	2,609	74,524	-	82,563	-	-	-	-	82,563
12-2026	4,544	2,144	64,266	-	70,954	-	-	-	-	70,954
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	142,405	76,950	1,284,154	-	1,503,509	-	-	-	-	1,503,509
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	142,405	76,950	1,284,154	-	1,503,509	-	-	-	-	1,503,509

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	2,951	52,704	16,223	-	-	71,878	28,899	28,899	27,554	27,554	16,532
12-2018	4,755	75,715	13,147	-	-	93,617	149,487	178,386	129,573	157,127	94,276
12-2019	4,323	71,590	-	-	-	75,914	161,202	339,588	127,025	284,152	170,491
12-2020	3,885	67,626	-	-	-	71,511	142,770	482,357	102,273	386,425	231,855
12-2021	3,371	65,336	-	1,362	-	70,069	108,840	591,198	70,880	457,305	274,383
12-2022	2,952	65,100	-	1,286	-	69,338	79,716	670,914	47,194	504,498	302,699
12-2023	2,569	64,179	-	2,782	-	69,531	55,209	726,123	29,714	534,212	320,527
12-2024	2,187	63,907	-	10,640	-	76,734	25,277	751,400	12,368	546,580	327,948
12-2025	1,877	62,839	-	32,470	-	97,187	(14,624)	736,776	(6,505)	540,075	324,045
12-2026	1,829	62,125	-	35,107	-	99,061	(28,107)	708,669	(11,365)	528,710	317,226
12-2027	-	-	-	50,405	-	50,405	(50,405)	658,264	(18,529)	510,181	306,109
12-2028	-	-	-	70,228	-	70,228	(70,228)	588,036	(23,469)	486,712	292,027
12-2029	-	-	-	91,147	-	91,147	(91,147)	496,889	(27,691)	459,021	275,413
12-2030	-	-	-	52,426	-	52,426	(52,426)	444,463	(14,479)	444,542	266,725
12-2031	-	-	-	35,341	-	35,341	(35,341)	409,122	(8,873)	435,669	261,401
12-2032	-	-	-	14,085	-	14,085	(14,085)	395,037	(3,215)	432,454	259,472
12-2033	-	-	-	-	-	-	-	395,037	-	432,454	259,472
12-2034	-	-	-	-	-	-	-	395,037	-	432,454	259,472
S-TOT	30,700	651,123	29,370	397,279	-	1,108,472	395,037		432,454		
REM	-	-	-	-	-	-	-	395,037	-	432,454	259,472
TOTAL	30,700	651,123	29,370	397,279	-	1,108,472	395,037		432,454		

LIFE - 10 years

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RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	21	352	383	11,793	577	127	138	4,245	208	52.78	34.07	5.45
12-2018	20	709	811	25,072	802	255	292	9,026	289	53.56	34.57	5.53
12-2019	18	557	687	21,350	845	200	247	7,686	304	54.66	35.29	5.65
12-2020	14	425	567	17,713	721	153	204	6,377	259	55.75	35.99	5.68
12-2021	11	296	433	13,597	643	106	156	4,895	232	56.96	36.77	5.69
12-2022	10	199	322	10,157	621	72	116	3,657	224	58.33	37.66	5.69
12-2023	7	114	220	6,985	602	41	79	2,515	217	59.50	38.41	5.80
12-2024	3	60	111	3,521	581	22	40	1,268	209	60.69	39.18	5.92
12-2025	2	20	35	1,113	541	7	13	401	195	61.91	39.96	6.04
12-2026	2	11	20	648	518	4	7	233	186	63.14	40.76	6.16
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
REM	-	-	-	-	-	-	-	-	-			
TOTAL	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
CUMULATIVE		164,814	-	3,066,209	-				-			
ULTIMATE		167,557	3,591	3,178,158	6,451				2,322			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	6,691	4,698	23,118	-	34,507	-	-	-	-	34,507
12-2018	13,661	10,098	49,946	-	73,705	-	-	-	-	73,705
12-2019	10,957	8,732	43,417	-	63,105	-	-	-	-	63,105
12-2020	8,534	7,352	36,228	-	52,114	-	-	-	-	52,114
12-2021	6,065	5,735	27,865	-	39,665	-	-	-	-	39,665
12-2022	4,187	4,366	20,804	-	29,357	-	-	-	-	29,357
12-2023	2,447	3,038	14,592	-	20,078	-	-	-	-	20,078
12-2024	1,315	1,565	7,504	-	10,384	-	-	-	-	10,384
12-2025	437	505	2,419	-	3,361	-	-	-	-	3,361
12-2026	258	300	1,437	-	1,995	-	-	-	-	1,995
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,360	12,470	7,277	-	-	21,107	13,400	13,400	12,776	12,776	7,666
12-2018	2,765	19,003	10	-	-	21,778	51,926	65,326	45,009	57,785	34,671
12-2019	2,385	16,216	-	-	-	18,601	44,504	109,830	35,069	92,854	55,712
12-2020	2,013	13,838	-	-	-	15,851	36,263	146,093	25,977	118,831	71,298
12-2021	1,584	12,207	-	956	-	14,747	24,918	171,011	16,227	135,058	81,035
12-2022	1,226	11,370	-	870	-	13,466	15,890	186,901	9,407	144,465	86,679
12-2023	887	9,701	-	870	-	11,458	8,620	195,522	4,640	149,105	89,463
12-2024	534	6,911	-	8,688	-	16,133	(5,749)	189,773	(2,813)	146,292	87,775
12-2025	279	2,150	-	8,402	-	10,831	(7,470)	182,303	(3,323)	142,970	85,782
12-2026	232	1,677	-	28,328	-	30,236	(28,242)	154,061	(11,420)	131,550	78,930
12-2027	-	-	-	28,988	-	28,988	(28,988)	125,073	(10,656)	120,894	72,536
12-2028	-	-	-	51,669	-	51,669	(51,669)	73,404	(17,267)	103,627	62,176
12-2029	-	-	-	74,437	-	74,437	(74,437)	(1,033)	(22,614)	81,013	48,608
12-2030	-	-	-	35,311	-	35,311	(35,311)	(36,344)	(9,752)	71,260	42,756
12-2031	-	-	-	33,765	-	33,765	(33,765)	(70,109)	(8,478)	62,783	37,670
12-2032	-	-	-	12,984	-	12,984	(12,984)	(83,093)	(2,964)	59,819	35,891
12-2033	-	-	-	-	-	-	-	(83,093)	-	59,819	35,891
12-2034	-	-	-	-	-	-	-	(83,093)	-	59,819	35,891
S-TOT	13,264	105,542	7,287	285,269	-	411,362	(83,093)		59,819		
REM	-	-	-	-	-	-	-	(83,093)	-	59,819	35,891
TOTAL	13,264	105,542	7,287	285,269	-	411,362	(83,093)		59,819		

LIFE - 10 years

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RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
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BP EXPLORATION AND PRODUCTION
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DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	2	168	135	23,811	1,319	84	67.46	11,906	659	55.85	22.26	4.81
12-2018	3	406	347	61,389	2,439	203	174	30,694	1,220	56.67	22.72	4.89
12-2019	3	399	353	62,336	2,400	200	176	31,168	1,200	57.84	23.36	4.99
12-2020	3	361	328	57,958	2,573	181	164	28,979	1,287	58.99	23.99	5.02
12-2021	3	303	281	49,770	2,642	152	141	24,885	1,321	60.27	24.69	5.03
12-2022	3	255	242	42,850	2,664	128	121	21,425	1,332	61.72	25.49	5.02
12-2023	3	215	208	36,842	2,683	108	104	18,421	1,342	62.96	26.17	5.12
12-2024	3	182	179	31,699	2,713	91	89	15,850	1,356	64.22	26.86	5.23
12-2025	3	152	153	27,054	2,744	76	76	13,527	1,372	65.50	27.56	5.33
12-2026	3	128	130	23,111	2,767	64	65	11,555	1,384	66.81	28.28	5.44
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,571	2,356	416,818	24,944	1,286	1,178	208,409	12,472	60.14	24.73	5.05
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,571	2,356	416,818	24,944	1,286	1,178	208,409	12,472	60.14	24.73	5.05
CUMULATIVE		2,448	-	368,315	-				-			
ULTIMATE		5,020	2,356	785,133	24,944				12,472			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	4,694	1,502	57,238	-	63,434	-	-	-	-	63,434
12-2018	11,516	3,946	149,959	-	165,421	-	-	-	-	165,421
12-2019	11,546	4,118	155,440	-	171,104	-	-	-	-	171,104
12-2020	10,659	3,930	145,358	-	159,947	-	-	-	-	159,947
12-2021	9,141	3,472	125,066	-	137,679	-	-	-	-	137,679
12-2022	7,883	3,085	107,620	-	118,588	-	-	-	-	118,588
12-2023	6,771	2,722	94,380	-	103,873	-	-	-	-	103,873
12-2024	5,831	2,403	82,831	-	91,065	-	-	-	-	91,065
12-2025	4,993	2,104	72,105	-	79,202	-	-	-	-	79,202
12-2026	4,286	1,844	62,829	-	68,959	-	-	-	-	68,959
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	77,320	29,126	1,052,826	-	1,159,272	-	-	-	-	1,159,272
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	77,320	29,126	1,052,826	-	1,159,272	-	-	-	-	1,159,272

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,361	39,754	8,946	-	-	50,061	13,373	13,373	12,751	12,751	7,650
12-2018	1,663	56,013	13,137	-	-	70,813	94,608	107,981	82,004	94,755	56,853
12-2019	1,696	54,648	-	-	-	56,344	114,760	222,741	90,429	185,184	111,111
12-2020	1,690	53,189	-	-	-	54,880	105,067	327,808	75,265	260,449	156,270
12-2021	1,657	52,502	-	-	-	54,159	83,520	411,328	54,391	314,840	188,904
12-2022	1,633	53,333	-	-	-	54,966	63,622	474,950	37,666	352,506	211,503
12-2023	1,616	54,057	-	1,011	-	56,683	47,190	522,140	25,398	377,904	226,742
12-2024	1,605	56,583	-	1,032	-	59,220	31,846	553,986	15,581	393,485	236,091
12-2025	1,598	60,689	-	2,238	-	64,525	14,677	568,663	6,528	400,014	240,008
12-2026	1,597	60,448	-	2,280	-	64,325	4,634	573,297	1,874	401,887	241,132
12-2027	-	-	-	17,547	-	17,547	(17,547)	555,750	(6,450)	395,437	237,262
12-2028	-	-	-	18,133	-	18,133	(18,133)	537,618	(6,060)	389,377	233,626
12-2029	-	-	-	16,710	-	16,710	(16,710)	520,907	(5,077)	384,301	230,580
12-2030	-	-	-	17,115	-	17,115	(17,115)	503,792	(4,727)	379,574	227,744
12-2031	-	-	-	1,576	-	1,576	(1,576)	502,217	(396)	379,178	227,507
12-2032	-	-	-	1,101	-	1,101	(1,101)	501,115	(251)	378,927	227,356
12-2033	-	-	-	-	-	-	-	501,115	-	378,927	227,356
12-2034	-	-	-	-	-	-	-	501,115	-	378,927	227,356
S-TOT	16,116	541,216	22,083	78,742	-	658,157	501,115		378,927		
REM	-	-	-	-	-	-	-	501,115	-	378,927	227,356
TOTAL	16,116	541,216	22,083	78,742	-	658,157	501,115		378,927		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	1	109	22	393	30	38	8	137	10	48.18	34.07	5.45
12-2018	1	153	30	530	43	53	10	185	15	48.89	34.57	5.53
12-2019	1	111	21	363	40	39	7	127	14	49.90	35.29	5.65
12-2020	1	82	16	286	-	29	6	100	-	50.89	35.99	5.68
12-2021	1	57	11	194	-	20	4	67	-	51.99	36.77	5.69
12-2022	1	40	8	131	-	14	3	46	-	53.25	37.66	5.69
12-2023	1	28	5	89	-	10	2	31	-	54.32	38.41	5.80
12-2024	1	20	4	61	-	7	1	21	-	55.40	39.18	5.92
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
CUMULATIVE		9,950	-	24,757	-				-			
ULTIMATE		10,551	116	26,805	114				40			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	1,836	256	745	-	2,836	-	-	-	-	2,836
12-2018	2,599	357	1,022	-	3,978	-	-	-	-	3,978
12-2019	1,932	259	715	-	2,906	-	-	-	-	2,906
12-2020	1,453	200	567	-	2,220	-	-	-	-	2,220
12-2021	1,040	141	384	-	1,566	-	-	-	-	1,566
12-2022	749	100	261	-	1,110	-	-	-	-	1,110
12-2023	537	71	180	-	788	-	-	-	-	788
12-2024	386	50	125	-	562	-	-	-	-	562
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	229	480	-	-	-	710	2,127	2,127	2,028	2,028	1,217
12-2018	326	699	-	-	-	1,026	2,953	5,079	2,559	4,587	2,752
12-2019	242	726	-	-	-	969	1,938	7,017	1,527	6,114	3,668
12-2020	182	598	-	-	-	781	1,440	8,456	1,031	7,145	4,287
12-2021	130	627	-	406	-	1,164	402	8,859	262	7,407	4,444
12-2022	93	397	-	415	-	906	204	9,062	121	7,527	4,516
12-2023	67	422	-	901	-	1,390	(602)	8,460	(324)	7,204	4,322
12-2024	48	413	-	920	-	1,381	(820)	7,641	(401)	6,802	4,081
12-2025	-	-	-	21,831	-	21,831	(21,831)	(14,190)	(9,710)	(2,908)	(1,745)
12-2026	-	-	-	4,500	-	4,500	(4,500)	(18,690)	(1,819)	(4,727)	(2,836)
12-2027	-	-	-	3,870	-	3,870	(3,870)	(22,559)	(1,422)	(6,150)	(3,690)
12-2028	-	-	-	426	-	426	(426)	(22,985)	(142)	(6,292)	(3,775)
12-2029	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2030	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2031	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2032	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2033	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2034	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
S-TOT	1,320	4,365	-	33,268	-	38,953	(22,985)		(6,292)		
REM	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
TOTAL	1,320	4,365	-	33,268	-	38,953	(22,985)		(6,292)		

LIFE - 10 years

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - BP NORTH SEA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	24	630	540	35,997	1,926	249	213	16,288	878	53.11	30.33	4.98
12-2018	24	1,301	1,225	93,398	3,285	528	494	43,109	1,524	54.38	29.97	5.02
12-2019	22	1,130	1,130	96,246	3,285	470	465	45,079	1,518	55.83	29.89	5.10
12-2020	18	915	964	85,279	3,294	386	400	40,116	1,546	57.10	30.28	5.12
12-2021	15	700	776	72,459	3,285	300	326	34,296	1,552	58.54	30.62	5.12
12-2022	14	538	623	62,277	3,285	235	265	29,696	1,556	60.18	30.93	5.11
12-2023	11	401	486	53,405	3,285	180	212	25,711	1,558	61.69	30.85	5.19
12-2024	7	305	349	45,076	3,294	141	158	22,036	1,566	63.24	30.07	5.27
12-2025	5	213	243	38,005	3,285	104	117	18,847	1,567	65.26	28.91	5.35
12-2026	5	179	206	33,530	3,285	88	100	16,674	1,570	66.64	29.20	5.45
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	6,311	6,540	615,670	31,509	2,680	2,750	291,852	14,834	57.66	30.20	5.15
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	6,311	6,540	615,670	31,509	2,680	2,750	291,852	14,834	57.66	30.20	5.15
CUMULATIVE		177,212	-	3,459,281	-				-			
ULTIMATE		183,523	6,540	4,074,951	31,509				14,834			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	13,221	6,456	81,100	-	100,777	-	-	-	-	100,777
12-2018	28,737	14,811	216,579	-	260,127	-	-	-	-	260,127
12-2019	26,248	13,911	229,986	-	270,145	-	-	-	-	270,145
12-2020	22,017	12,112	205,532	-	239,661	-	-	-	-	239,661
12-2021	17,540	9,967	175,675	-	203,183	-	-	-	-	203,183
12-2022	14,137	8,206	151,635	-	173,978	-	-	-	-	173,978
12-2023	11,105	6,530	133,463	-	151,098	-	-	-	-	151,098
12-2024	8,904	4,758	116,053	-	129,715	-	-	-	-	129,715
12-2025	6,785	3,372	100,746	-	110,903	-	-	-	-	110,903
12-2026	5,867	2,921	90,829	-	99,616	-	-	-	-	99,616
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	154,561	83,044	1,501,597	-	1,739,202	-	-	-	-	1,739,202
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	154,561	83,044	1,501,597	-	1,739,202	-	-	-	-	1,739,202

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	2,951	52,704	16,223	-	-	71,878	28,899	28,899	27,554	27,554	16,532
12-2018	4,798	77,559	13,147	-	-	95,504	164,623	193,522	142,693	170,247	102,148
12-2019	4,406	75,334	-	-	-	79,740	190,405	383,927	150,036	320,283	192,170
12-2020	3,949	70,490	-	-	-	74,438	165,223	549,150	118,357	438,641	263,184
12-2021	3,432	68,182	-	1,362	-	72,976	130,207	679,357	84,794	523,435	314,061
12-2022	3,015	68,153	-	1,286	-	72,454	101,524	780,881	60,105	583,540	350,124
12-2023	2,635	67,450	-	2,782	-	72,866	78,231	859,112	42,105	625,644	375,387
12-2024	2,255	67,290	-	10,640	-	80,185	49,530	908,643	24,234	649,878	389,927
12-2025	1,946	66,186	-	32,470	-	100,602	10,301	918,943	4,582	654,460	392,676
12-2026	1,898	65,351	-	35,107	-	102,356	(2,740)	916,203	(1,108)	653,352	392,011
12-2027	-	-	-	50,405	-	50,405	(50,405)	865,798	(18,529)	634,823	380,894
12-2028	-	-	-	70,228	-	70,228	(70,228)	795,571	(23,469)	611,354	366,813
12-2029	-	-	-	91,147	-	91,147	(91,147)	704,423	(27,691)	583,664	350,198
12-2030	-	-	-	52,426	-	52,426	(52,426)	651,997	(14,479)	569,184	341,511
12-2031	-	-	-	35,341	-	35,341	(35,341)	616,657	(8,873)	560,311	336,187
12-2032	-	-	-	14,085	-	14,085	(14,085)	602,571	(3,215)	557,096	334,258
12-2033	-	-	-	-	-	-	-	602,571	-	557,096	334,258
12-2034	-	-	-	-	-	-	-	602,571	-	557,096	334,258
S-TOT	31,283	678,699	29,370	397,279	-	1,136,631	602,571		557,096		
REM	-	-	-	-	-	-	-	602,571	-	557,096	334,258
TOTAL	31,283	678,699	29,370	397,279	-	1,136,631	602,571		557,096		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	21	352	383	11,793	577	127	138	4,245	208	52.78	34.07	5.45
12-2018	20	709	811	25,072	802	255	292	9,026	289	53.56	34.57	5.53
12-2019	18	557	687	21,350	845	200	247	7,686	304	54.66	35.29	5.65
12-2020	14	425	567	17,713	721	153	204	6,377	259	55.75	35.99	5.68
12-2021	11	296	433	13,597	643	106	156	4,895	232	56.96	36.77	5.69
12-2022	10	199	322	10,157	621	72	116	3,657	224	58.33	37.66	5.69
12-2023	7	114	220	6,985	602	41	79	2,515	217	59.50	38.41	5.80
12-2024	3	60	111	3,521	581	22	40	1,268	209	60.69	39.18	5.92
12-2025	2	20	35	1,113	541	7	13	401	195	61.91	39.96	6.04
12-2026	2	11	20	648	518	4	7	233	186	63.14	40.76	6.16
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
REM	-	-	-	-	-	-	-	-	-			
TOTAL	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
CUMULATIVE		164,814	-	3,066,209	-				-			
ULTIMATE		167,557	3,591	3,178,158	6,451				2,322			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	6,691	4,698	23,118	-	34,507	-	-	-	-	34,507
12-2018	13,661	10,098	49,946	-	73,705	-	-	-	-	73,705
12-2019	10,957	8,732	43,417	-	63,105	-	-	-	-	63,105
12-2020	8,534	7,352	36,228	-	52,114	-	-	-	-	52,114
12-2021	6,065	5,735	27,865	-	39,665	-	-	-	-	39,665
12-2022	4,187	4,366	20,804	-	29,357	-	-	-	-	29,357
12-2023	2,447	3,038	14,592	-	20,078	-	-	-	-	20,078
12-2024	1,315	1,565	7,504	-	10,384	-	-	-	-	10,384
12-2025	437	505	2,419	-	3,361	-	-	-	-	3,361
12-2026	258	300	1,437	-	1,995	-	-	-	-	1,995
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,360	12,470	7,277	-	-	21,107	13,400	13,400	12,776	12,776	7,666
12-2018	2,765	18,201	10	-	-	20,977	52,728	66,128	45,704	58,480	35,088
12-2019	2,385	15,072	-	-	-	17,457	45,649	111,776	35,970	94,450	56,670
12-2020	2,013	12,961	-	-	-	14,974	37,140	148,916	26,605	121,055	72,633
12-2021	1,584	11,299	-	956	-	13,839	25,826	174,742	16,818	137,874	82,724
12-2022	1,226	10,366	-	870	-	12,462	16,895	191,636	10,002	147,876	88,725
12-2023	887	8,669	-	870	-	10,426	9,652	201,288	5,195	153,070	91,842
12-2024	534	6,091	-	8,688	-	15,313	(4,929)	196,359	(2,412)	150,659	90,395
12-2025	279	1,701	-	8,402	-	10,382	(7,021)	189,339	(3,123)	147,536	88,522
12-2026	232	1,694	-	28,328	-	30,254	(28,259)	161,079	(11,427)	136,109	81,665
12-2027	-	-	-	28,988	-	28,988	(28,988)	132,091	(10,656)	125,453	75,272
12-2028	-	-	-	51,669	-	51,669	(51,669)	80,422	(17,267)	108,186	64,912
12-2029	-	-	-	74,437	-	74,437	(74,437)	5,985	(22,614)	85,572	51,343
12-2030	-	-	-	35,311	-	35,311	(35,311)	(29,326)	(9,752)	75,820	45,492
12-2031	-	-	-	33,765	-	33,765	(33,765)	(63,091)	(8,478)	67,342	40,405
12-2032	-	-	-	12,984	-	12,984	(12,984)	(76,075)	(2,964)	64,378	38,627
12-2033	-	-	-	-	-	-	-	(76,075)	-	64,378	38,627
12-2034	-	-	-	-	-	-	-	(76,075)	-	64,378	38,627
S-TOT	13,264	98,524	7,287	285,269	-	404,344	(76,075)		64,378		
REM	-	-	-	-	-	-	-	(76,075)	-	64,378	38,627
TOTAL	13,264	98,524	7,287	285,269	-	404,344	(76,075)		64,378		

LIFE - 10 years

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	2	168	135	23,811	1,319	84	67.46	11,906	659	55.85	22.26	4.81
12-2018	3	440	384	67,796	2,439	220	192	33,898	1,220	56.67	22.72	4.89
12-2019	3	462	421	74,532	2,400	231	211	37,266	1,200	57.84	23.36	4.99
12-2020	3	408	380	67,280	2,573	204	190	33,640	1,287	58.99	23.99	5.02
12-2021	3	346	331	58,668	2,642	173	166	29,334	1,321	60.27	24.69	5.03
12-2022	3	298	293	51,988	2,664	149	147	25,994	1,332	61.72	25.49	5.02
12-2023	3	258	261	46,331	2,683	129	131	23,166	1,342	62.96	26.17	5.12
12-2024	3	224	234	41,494	2,713	112	117	20,747	1,356	64.22	26.86	5.23
12-2025	3	194	208	36,892	2,744	97	104	18,446	1,372	65.50	27.56	5.33
12-2026	3	168	185	32,882	2,767	84	93	16,441	1,384	66.81	28.28	5.44
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,967	2,833	501,673	24,944	1,483	1,417	250,837	12,472	60.32	24.86	5.06
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,967	2,833	501,673	24,944	1,483	1,417	250,837	12,472	60.32	24.86	5.06
CUMULATIVE		2,448	-	368,315	-				-			
ULTIMATE		5,415	2,833	869,988	24,944				12,472			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	4,694	1,502	57,238	-	63,434	-	-	-	-	63,434
12-2018	12,477	4,356	165,611	-	182,444	-	-	-	-	182,444
12-2019	13,359	4,921	185,854	-	204,133	-	-	-	-	204,133
12-2020	12,029	4,560	168,738	-	185,327	-	-	-	-	185,327
12-2021	10,435	4,091	147,427	-	161,952	-	-	-	-	161,952
12-2022	9,201	3,740	130,570	-	143,511	-	-	-	-	143,511
12-2023	8,121	3,421	118,690	-	130,231	-	-	-	-	130,231
12-2024	7,203	3,143	108,424	-	118,770	-	-	-	-	118,770
12-2025	6,348	2,867	98,327	-	107,542	-	-	-	-	107,542
12-2026	5,609	2,621	89,392	-	97,621	-	-	-	-	97,621
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	89,476	35,220	1,270,270	-	1,394,966	-	-	-	-	1,394,966
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	89,476	35,220	1,270,270	-	1,394,966	-	-	-	-	1,394,966

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,361	39,754	8,946	-	-	50,061	13,373	13,373	12,751	12,751	7,650
12-2018	1,706	58,658	13,137	-	-	73,501	108,943	122,316	94,430	107,180	64,308
12-2019	1,778	59,536	-	-	-	61,314	142,819	265,135	112,539	219,720	131,832
12-2020	1,754	56,930	-	-	-	58,684	126,643	391,778	90,721	310,441	186,264
12-2021	1,718	56,256	-	-	-	57,973	103,979	495,757	67,714	378,155	226,893
12-2022	1,696	57,390	-	-	-	59,086	84,426	580,182	49,982	428,137	256,882
12-2023	1,681	58,358	-	1,011	-	61,050	69,181	649,364	37,234	465,370	279,222
12-2024	1,673	60,786	-	1,032	-	63,491	55,279	704,643	27,047	492,417	295,450
12-2025	1,667	64,485	-	2,238	-	68,390	39,152	743,795	17,415	509,832	305,899
12-2026	1,666	63,657	-	2,280	-	67,602	30,019	773,814	12,138	521,970	313,182
12-2027	-	-	-	17,547	-	17,547	(17,547)	756,267	(6,450)	515,520	309,312
12-2028	-	-	-	18,133	-	18,133	(18,133)	738,134	(6,060)	509,460	305,676
12-2029	-	-	-	16,710	-	16,710	(16,710)	721,424	(5,077)	504,384	302,630
12-2030	-	-	-	17,115	-	17,115	(17,115)	704,309	(4,727)	499,657	299,794
12-2031	-	-	-	1,576	-	1,576	(1,576)	702,733	(396)	499,261	299,557
12-2032	-	-	-	1,101	-	1,101	(1,101)	701,632	(251)	499,010	299,406
12-2033	-	-	-	-	-	-	-	701,632	-	499,010	299,406
12-2034	-	-	-	-	-	-	-	701,632	-	499,010	299,406
S-TOT	16,699	575,810	22,083	78,742	-	693,334	701,632		499,010		
REM	-	-	-	-	-	-	-	701,632	-	499,010	299,406
TOTAL	16,699	575,810	22,083	78,742	-	693,334	701,632		499,010		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	1	109	22	393	30	38	8	137	10	48.18	34.07	5.45
12-2018	1	153	30	530	43	53	10	185	15	48.89	34.57	5.53
12-2019	1	111	21	363	40	39	7	127	14	49.90	35.29	5.65
12-2020	1	82	16	286	-	29	6	100	-	50.89	35.99	5.68
12-2021	1	57	11	194	-	20	4	67	-	51.99	36.77	5.69
12-2022	1	40	8	131	-	14	3	46	-	53.25	37.66	5.69
12-2023	1	28	5	89	-	10	2	31	-	54.32	38.41	5.80
12-2024	1	20	4	61	-	7	1	21	-	55.40	39.18	5.92
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
CUMULATIVE		9,950	-	24,757	-				-			
ULTIMATE		10,551	116	26,805	114				40			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	1,836	256	745	-	2,836	-	-	-	-	2,836
12-2018	2,599	357	1,022	-	3,978	-	-	-	-	3,978
12-2019	1,932	259	715	-	2,906	-	-	-	-	2,906
12-2020	1,453	200	567	-	2,220	-	-	-	-	2,220
12-2021	1,040	141	384	-	1,566	-	-	-	-	1,566
12-2022	749	100	261	-	1,110	-	-	-	-	1,110
12-2023	537	71	180	-	788	-	-	-	-	788
12-2024	386	50	125	-	562	-	-	-	-	562
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	229	480	-	-	-	710	2,127	2,127	2,028	2,028	1,217
12-2018	326	699	-	-	-	1,026	2,953	5,079	2,559	4,587	2,752
12-2019	242	726	-	-	-	969	1,938	7,017	1,527	6,114	3,668
12-2020	182	598	-	-	-	781	1,440	8,456	1,031	7,145	4,287
12-2021	130	627	-	406	-	1,164	402	8,859	262	7,407	4,444
12-2022	93	397	-	415	-	906	204	9,062	121	7,527	4,516
12-2023	67	422	-	901	-	1,390	(602)	8,460	(324)	7,204	4,322
12-2024	48	413	-	920	-	1,381	(820)	7,641	(401)	6,802	4,081
12-2025	-	-	-	21,831	-	21,831	(21,831)	(14,190)	(9,710)	(2,908)	(1,745)
12-2026	-	-	-	4,500	-	4,500	(4,500)	(18,690)	(1,819)	(4,727)	(2,836)
12-2027	-	-	-	3,870	-	3,870	(3,870)	(22,559)	(1,422)	(6,150)	(3,690)
12-2028	-	-	-	426	-	426	(426)	(22,985)	(142)	(6,292)	(3,775)
12-2029	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2030	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2031	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2032	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2033	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
12-2034	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
S-TOT	1,320	4,365	-	33,268	-	38,953	(22,985)		(6,292)		
REM	-	-	-	-	-	-	-	(22,985)	-	(6,292)	(3,775)
TOTAL	1,320	4,365	-	33,268	-	38,953	(22,985)		(6,292)		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - BP NORTH SEA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALES GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	GAS $/M
12-2017	24	565	482	34,254	1,926	226	192	15,661	878	53.15	29.93	4.96
12-2018	24	989	899	74,897	3,285	408	369	35,010	1,524	54.41	29.34	5.00
12-2019	22	827	807	68,953	3,285	345	333	32,312	1,518	55.71	29.86	5.10
12-2020	18	670	701	60,301	3,294	281	289	28,263	1,546	56.94	30.50	5.13
12-2021	15	483	539	45,961	3,285	204	222	21,504	1,552	58.24	31.32	5.14
12-2022	14	339	395	34,371	3,285	144	163	16,118	1,556	59.75	32.03	5.14
12-2023	11	229	288	25,560	3,285	99	120	12,009	1,558	61.09	32.61	5.24
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	4,102	4,112	344,298	21,645	1,706	1,688	160,876	10,132	56.22	30.46	5.09
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	4,102	4,112	344,298	21,645	1,706	1,688	160,876	10,132	56.22	30.46	5.09
CUMULATIVE		177,212	-	3,459,281	-				-			
ULTIMATE		181,314	4,112	3,803,578	21,645				10,132			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	11,998	5,750	77,685	-	95,433	-	-	-	-	95,433
12-2018	22,184	10,817	175,094	-	208,095	-	-	-	-	208,095
12-2019	19,204	9,938	164,817	-	193,959	-	-	-	-	193,959
12-2020	16,020	8,823	144,989	-	169,831	-	-	-	-	169,831
12-2021	11,864	6,957	110,600	-	129,421	-	-	-	-	129,421
12-2022	8,613	5,231	82,788	-	96,632	-	-	-	-	96,632
12-2023	6,054	3,900	62,872	-	72,825	-	-	-	-	72,825
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	95,935	51,416	818,845	-	966,197	-	-	-	-	966,197
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	95,935	51,416	818,845	-	966,197	-	-	-	-	966,197

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	2,760	52,791	16,223	-	-	71,774	23,659	23,659	22,558	22,558	13,535
12-2018	3,846	74,602	13,147	-	-	91,595	116,500	140,159	100,980	123,538	74,123
12-2019	3,581	68,841	-	-	-	72,421	121,538	261,697	95,770	219,308	131,585
12-2020	3,305	64,099	-	-	-	67,404	102,428	364,124	73,374	292,682	175,609
12-2021	2,904	60,504	-	-	-	63,408	66,012	430,137	42,989	335,672	201,403
12-2022	2,537	59,390	-	-	-	61,927	34,706	464,842	20,547	356,218	213,731
12-2023	2,268	57,910	-	-	-	60,179	12,647	477,489	6,807	363,025	217,815
12-2024	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2025	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2026	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2027	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2028	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2029	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2030	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2031	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2032	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2033	-	-	-	-	-	-	-	477,489	-	363,025	217,815
12-2034	-	-	-	-	-	-	-	477,489	-	363,025	217,815
S-TOT	21,201	438,136	29,370	-	-	488,707	477,489		363,025		
REM	-	-	-	-	-	-	-	477,489	-	363,025	217,815
TOTAL	21,201	438,136	29,370	-	-	488,707	477,489		363,025		

LIFE - 7 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALES GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	GAS $/M
12-2017	21	288	326	10,050	577	104	117	3,618	208	52.78	34.07	5.45
12-2018	20	455	543	16,839	802	164	196	6,062	289	53.56	34.57	5.53
12-2019	18	372	484	15,071	845	134	174	5,425	304	54.66	35.29	5.65
12-2020	14	294	420	13,174	721	106	151	4,743	259	55.75	35.99	5.68
12-2021	11	207	328	10,339	643	75	118	3,722	232	56.96	36.77	5.69
12-2022	10	136	236	7,481	621	49	85	2,693	224	58.33	37.66	5.69
12-2023	7	80	170	5,413	602	29	61	1,949	217	59.50	38.41	5.80
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	21	1,832	2,507	78,368	4,810	660	903	28,212	1,732	55.01	35.72	5.62
REM	-	-	-	-	-	-	-	-	-			
TOTAL	21	1,832	2,507	78,368	4,810	660	903	28,212	1,732	55.01	35.72	5.62
CUMULATIVE		164,814	-	3,066,209	-				-			
ULTIMATE		166,646	2,507	3,144,577	4,810				1,732			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	5,468	3,993	19,702	-	29,162	-	-	-	-	29,162
12-2018	8,770	6,762	33,545	-	49,077	-	-	-	-	49,077
12-2019	7,320	6,143	30,647	-	44,110	-	-	-	-	44,110
12-2020	5,907	5,447	26,946	-	38,299	-	-	-	-	38,299
12-2021	4,250	4,343	21,188	-	29,781	-	-	-	-	29,781
12-2022	2,853	3,204	15,323	-	21,380	-	-	-	-	21,380
12-2023	1,718	2,346	11,309	-	15,374	-	-	-	-	15,374
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	36,285	32,239	158,660	-	227,183	-	-	-	-	227,183
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	36,285	32,239	158,660	-	227,183	-	-	-	-	227,183

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	1,169	11,489	7,277	-	-	19,936	9,227	9,227	8,797	8,797	5,278
12-2018	1,885	15,121	10	-	-	17,017	32,060	41,287	27,789	36,587	21,952
12-2019	1,708	13,841	-	-	-	15,549	28,562	69,849	22,506	59,093	35,456
12-2020	1,515	12,514	-	-	-	14,029	24,269	94,118	17,385	76,478	45,887
12-2021	1,224	11,961	-	-	-	13,185	16,596	110,714	10,808	87,286	52,372
12-2022	932	11,770	-	-	-	12,702	8,678	119,392	5,138	92,424	55,454
12-2023	714	11,274	-	-	-	11,988	3,386	122,778	1,822	94,246	56,548
12-2024	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2025	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2026	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2027	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2028	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2029	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2030	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2031	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2032	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2033	-	-	-	-	-	-	-	122,778	-	94,246	56,548
12-2034	-	-	-	-	-	-	-	122,778	-	94,246	56,548
S-TOT	9,147	87,970	7,287	-	-	104,405	122,778		94,246		
REM	-	-	-	-	-	-	-	122,778	-	94,246	56,548
TOTAL	9,147	87,970	7,287	-	-	104,405	122,778		94,246		

LIFE - 7 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	2	168	135	23,811	1,319	84	67.46	11,906	659	55.85	22.26	4.81
12-2018	3	382	326	57,528	2,439	191	163	28,764	1,220	56.67	22.72	4.89
12-2019	3	344	303	53,519	2,400	172	151	26,760	1,200	57.84	23.36	4.99
12-2020	3	294	265	46,840	2,573	147	132	23,420	1,287	58.99	23.99	5.02
12-2021	3	218	200	35,428	2,642	109	100	17,714	1,321	60.27	24.69	5.03
12-2022	3	162	151	26,758	2,664	81	76	13,379	1,332	61.72	25.49	5.02
12-2023	3	121	113	20,057	2,683	60	57	10,029	1,342	62.96	26.17	5.12
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	1,689	1,493	263,942	16,721	844	746	131,971	8,360	58.63	23.84	4.97
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	1,689	1,493	263,942	16,721	844	746	131,971	8,360	58.63	23.84	4.97
CUMULATIVE		2,448	-	368,315	-				-			
ULTIMATE		4,137	1,493	632,257	16,721				8,360			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	4,694	1,502	57,238	-	63,434	-	-	-	-	63,434
12-2018	10,815	3,698	140,527	-	155,040	-	-	-	-	155,040
12-2019	9,952	3,536	133,455	-	146,943	-	-	-	-	146,943
12-2020	8,660	3,176	117,476	-	129,312	-	-	-	-	129,312
12-2021	6,573	2,472	89,028	-	98,073	-	-	-	-	98,073
12-2022	5,011	1,927	67,205	-	74,143	-	-	-	-	74,143
12-2023	3,798	1,483	51,382	-	56,663	-	-	-	-	56,663
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	49,503	17,793	656,312	-	723,608	-	-	-	-	723,608
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	49,503	17,793	656,312	-	723,608	-	-	-	-	723,608

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	1,361	40,821	8,946	-	-	51,128	12,306	12,306	11,733	11,733	7,040
12-2018	1,635	58,781	13,137	-	-	73,553	81,487	93,793	70,632	82,365	49,419
12-2019	1,630	54,274	-	-	-	55,904	91,039	184,831	71,737	154,102	92,461
12-2020	1,607	50,986	-	-	-	52,594	76,719	261,550	54,958	209,059	125,436
12-2021	1,549	47,916	-	-	-	49,465	48,608	310,158	31,655	240,714	144,428
12-2022	1,511	47,223	-	-	-	48,734	25,409	335,566	15,043	255,757	153,454
12-2023	1,488	46,214	-	-	-	47,702	8,962	344,528	4,823	260,580	156,348
12-2024	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2025	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2026	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2027	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2028	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2029	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2030	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2031	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2032	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2033	-	-	-	-	-	-	-	344,528	-	260,580	156,348
12-2034	-	-	-	-	-	-	-	344,528	-	260,580	156,348
S-TOT	10,782	346,215	22,083	-	-	379,080	344,528		260,580		
REM	-	-	-	-	-	-	-	344,528	-	260,580	156,348
TOTAL	10,782	346,215	22,083	-	-	379,080	344,528		260,580		

LIFE - 7 years

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RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL PROVED RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	SALE GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	1	109	22	393	30	38	8	137	10	48.18	34.07	5.45
12-2018	1	153	30	530	43	53	10	185	15	48.89	34.57	5.53
12-2019	1	111	21	363	40	39	7	127	14	49.90	35.29	5.65
12-2020	1	82	16	286	-	29	6	100	-	50.89	35.99	5.68
12-2021	1	57	11	194	-	20	4	67	-	51.99	36.77	5.69
12-2022	1	40	8	131	-	14	3	46	-	53.25	37.66	5.69
12-2023	1	28	5	89	-	10	2	31	-	54.32	38.41	5.80
12-2024	-	-	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	581	112	1,987	114	203	39	692	40	50.11	35.42	5.60
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	581	112	1,987	114	203	39	692	40	50.11	35.42	5.60
CUMULATIVE		9,950	-	24,757	-				-			
ULTIMATE		10,531	112	26,744	114				40			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	1,836	256	745	-	2,836	-	-	-	-	2,836
12-2018	2,599	357	1,022	-	3,978	-	-	-	-	3,978
12-2019	1,932	259	715	-	2,906	-	-	-	-	2,906
12-2020	1,453	200	567	-	2,220	-	-	-	-	2,220
12-2021	1,040	141	384	-	1,566	-	-	-	-	1,566
12-2022	749	100	261	-	1,110	-	-	-	-	1,110
12-2023	537	71	180	-	788	-	-	-	-	788
12-2024	-	-	-	-	-	-	-	-	-	-
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	10,147	1,385	3,873	-	15,406	-	-	-	-	15,406
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	10,147	1,385	3,873	-	15,406	-	-	-	-	15,406

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ 10% M$
12-2017	229	480	-	-	-	710	2,127	2,127	2,028	2,028	1,217
12-2018	326	699	-	-	-	1,026	2,953	5,079	2,559	4,587	2,752
12-2019	242	726	-	-	-	969	1,938	7,017	1,527	6,114	3,668
12-2020	182	598	-	-	-	781	1,440	8,456	1,031	7,145	4,287
12-2021	130	627	-	-	-	757	808	9,265	526	7,671	4,603
12-2022	93	397	-	-	-	491	619	9,884	367	8,038	4,823
12-2023	67	422	-	-	-	489	299	10,183	161	8,199	4,919
12-2024	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2025	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2026	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2027	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2028	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2029	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2030	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2031	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2032	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2033	-	-	-	-	-	-	-	10,183	-	8,199	4,919
12-2034	-	-	-	-	-	-	-	10,183	-	8,199	4,919
S-TOT	1,272	3,951	-	-	-	5,223	10,183		8,199		
REM	-	-	-	-	-	-	-	10,183	-	8,199	4,919
TOTAL	1,272	3,951	-	-	-	5,223	10,183		8,199		

LIFE - 7 years

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PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - BP NORTH SEA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	24	630	540	35,997	1,926	249	213	16,288	878	53.11	30.33	4.98
12-2018	24	1,268	1,188	86,991	3,285	511	476	39,905	1,524	54.31	30.25	5.04
12-2019	22	1,067	1,061	84,049	3,285	439	431	38,980	1,518	55.69	30.41	5.12
12-2020	18	869	911	75,957	3,294	362	374	35,455	1,546	56.98	30.73	5.14
12-2021	15	657	726	63,560	3,285	278	300	29,847	1,552	58.40	31.11	5.14
12-2022	14	495	572	53,139	3,285	214	240	25,127	1,556	60.03	31.51	5.12
12-2023	11	358	433	43,916	3,285	159	185	20,966	1,558	61.52	31.53	5.21
12-2024	7	262	294	35,281	3,294	119	131	17,139	1,566	63.06	30.75	5.28
12-2025	5	172	188	28,167	3,285	83	89	13,927	1,567	65.20	29.33	5.35
12-2026	5	140	151	23,759	3,285	68	73	11,789	1,570	66.59	29.55	5.45
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	5,916	6,063	530,815	31,509	2,483	2,511	249,424	14,834	57.36	30.65	5.15
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	5,916	6,063	530,815	31,509	2,483	2,511	249,424	14,834	57.36	30.65	5.15
CUMULATIVE		177,212	-	3,459,281	-				-			
ULTIMATE		183,128	6,063	3,990,096	31,509				14,834			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	13,221	6,456	81,100	-	100,777	-	-	-	-	100,777
12-2018	27,776	14,401	200,927	-	243,104	-	-	-	-	243,104
12-2019	24,435	13,109	199,572	-	237,116	-	-	-	-	237,116
12-2020	20,647	11,482	182,153	-	214,281	-	-	-	-	214,281
12-2021	16,246	9,349	153,315	-	178,909	-	-	-	-	178,909
12-2022	12,819	7,551	128,684	-	149,054	-	-	-	-	149,054
12-2023	9,756	5,831	109,153	-	124,740	-	-	-	-	124,740
12-2024	7,532	4,019	90,460	-	102,011	-	-	-	-	102,011
12-2025	5,429	2,609	74,524	-	82,563	-	-	-	-	82,563
12-2026	4,544	2,144	64,266	-	70,954	-	-	-	-	70,954
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	142,405	76,950	1,284,154	-	1,503,509	-	-	-	-	1,503,509
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	142,405	76,950	1,284,154	-	1,503,509	-	-	-	-	1,503,509

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	2,951	52,704	16,223	-	-	71,878	28,899	28,899	27,554	27,554	16,532
12-2018	4,755	75,715	13,147	-	-	93,617	149,487	178,386	129,573	157,127	94,276
12-2019	4,323	71,590	-	-	-	75,914	161,202	339,588	127,025	284,152	170,491
12-2020	3,885	67,626	-	-	-	71,511	142,770	482,357	102,273	386,425	231,855
12-2021	3,371	65,336	-	-	-	68,707	110,202	592,559	71,767	458,191	274,915
12-2022	2,952	65,100	-	-	-	68,052	81,002	673,561	47,955	506,147	303,688
12-2023	2,569	64,179	-	-	-	66,749	57,991	731,553	31,211	537,358	322,415
12-2024	2,187	63,907	-	-	-	66,094	35,917	767,469	17,573	554,931	332,959
12-2025	1,877	62,839	-	-	-	64,717	17,847	785,316	7,938	562,869	337,721
12-2026	1,829	62,125	-	-	-	63,954	7,000	792,316	2,831	565,700	339,420
12-2027	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2028	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2029	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2030	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2031	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2032	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2033	-	-	-	-	-	-	-	792,316	-	565,700	339,420
12-2034	-	-	-	-	-	-	-	792,316	-	565,700	339,420
S-TOT	30,700	651,123	29,370	-	-	711,193	792,316		565,700		
REM	-	-	-	-	-	-	-	792,316	-	565,700	339,420
TOTAL	30,700	651,123	29,370	-	-	711,193	792,316		565,700		

LIFE - 10 years

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DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	21	352	383	11,793	577	127	138	4,245	208	52.78	34.07	5.45
12-2018	20	709	811	25,072	802	255	292	9,026	289	53.56	34.57	5.53
12-2019	18	557	687	21,350	845	200	247	7,686	304	54.66	35.29	5.65
12-2020	14	425	567	17,713	721	153	204	6,377	259	55.75	35.99	5.68
12-2021	11	296	433	13,597	643	106	156	4,895	232	56.96	36.77	5.69
12-2022	10	199	322	10,157	621	72	116	3,657	224	58.33	37.66	5.69
12-2023	7	114	220	6,985	602	41	79	2,515	217	59.50	38.41	5.80
12-2024	3	60	111	3,521	581	22	40	1,268	209	60.69	39.18	5.92
12-2025	2	20	35	1,113	541	7	13	401	195	61.91	39.96	6.04
12-2026	2	11	20	648	518	4	7	233	186	63.14	40.76	6.16
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
REM	-	-	-	-	-	-	-	-	-			
TOTAL	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
CUMULATIVE		164,814	-	3,066,209	-				-			
ULTIMATE		167,557	3,591	3,178,158	6,451				2,322			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	6,691	4,698	23,118	-	34,507	-	-	-	-	34,507
12-2018	13,661	10,098	49,946	-	73,705	-	-	-	-	73,705
12-2019	10,957	8,732	43,417	-	63,105	-	-	-	-	63,105
12-2020	8,534	7,352	36,228	-	52,114	-	-	-	-	52,114
12-2021	6,065	5,735	27,865	-	39,665	-	-	-	-	39,665
12-2022	4,187	4,366	20,804	-	29,357	-	-	-	-	29,357
12-2023	2,447	3,038	14,592	-	20,078	-	-	-	-	20,078
12-2024	1,315	1,565	7,504	-	10,384	-	-	-	-	10,384
12-2025	437	505	2,419	-	3,361	-	-	-	-	3,361
12-2026	258	300	1,437	-	1,995	-	-	-	-	1,995
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,360	12,470	7,277	-	-	21,107	13,400	13,400	12,776	12,776	7,666
12-2018	2,765	19,003	10	-	-	21,778	51,926	65,326	45,009	57,785	34,671
12-2019	2,385	16,216	-	-	-	18,601	44,504	109,830	35,069	92,854	55,712
12-2020	2,013	13,838	-	-	-	15,851	36,263	146,093	25,977	118,831	71,298
12-2021	1,584	12,207	-	-	-	13,791	25,873	171,967	16,850	135,680	81,408
12-2022	1,226	11,370	-	-	-	12,596	16,761	188,728	9,923	145,603	87,362
12-2023	887	9,701	-	-	-	10,587	9,491	198,218	5,108	150,711	90,427
12-2024	534	6,911	-	-	-	7,444	2,939	201,158	1,438	152,149	91,290
12-2025	279	2,150	-	-	-	2,429	932	202,090	414	152,564	91,538
12-2026	232	1,677	-	-	-	1,909	86	202,176	35	152,599	91,559
12-2027	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2028	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2029	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2030	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2031	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2032	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2033	-	-	-	-	-	-	-	202,176	-	152,599	91,559
12-2034	-	-	-	-	-	-	-	202,176	-	152,599	91,559
S-TOT	13,264	105,542	7,287	-	-	126,094	202,176		152,599		
REM	-	-	-	-	-	-	-	202,176	-	152,599	91,559
TOTAL	13,264	105,542	7,287	-	-	126,094	202,176		152,599		

LIFE - 10 years

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	2	168	135	23,811	1,319	84	67.46	11,906	659	55.85	22.26	4.81
12-2018	3	406	347	61,389	2,439	203	174	30,694	1,220	56.67	22.72	4.89
12-2019	3	399	353	62,336	2,400	200	176	31,168	1,200	57.84	23.36	4.99
12-2020	3	361	328	57,958	2,573	181	164	28,979	1,287	58.99	23.99	5.02
12-2021	3	303	281	49,770	2,642	152	141	24,885	1,321	60.27	24.69	5.03
12-2022	3	255	242	42,850	2,664	128	121	21,425	1,332	61.72	25.49	5.02
12-2023	3	215	208	36,842	2,683	108	104	18,421	1,342	62.96	26.17	5.12
12-2024	3	182	179	31,699	2,713	91	89	15,850	1,356	64.22	26.86	5.23
12-2025	3	152	153	27,054	2,744	76	76	13,527	1,372	65.50	27.56	5.33
12-2026	3	128	130	23,111	2,767	64	65	11,555	1,384	66.81	28.28	5.44
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,571	2,356	416,818	24,944	1,286	1,178	208,409	12,472	60.14	24.73	5.05
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,571	2,356	416,818	24,944	1,286	1,178	208,409	12,472	60.14	24.73	5.05
CUMULATIVE		2,448	-	368,315	-				-			
ULTIMATE		5,020	2,356	785,133	24,944				12,472			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	4,694	1,502	57,238	-	63,434	-	-	-	-	63,434
12-2018	11,516	3,946	149,959	-	165,421	-	-	-	-	165,421
12-2019	11,546	4,118	155,440	-	171,104	-	-	-	-	171,104
12-2020	10,659	3,930	145,358	-	159,947	-	-	-	-	159,947
12-2021	9,141	3,472	125,066	-	137,679	-	-	-	-	137,679
12-2022	7,883	3,085	107,620	-	118,588	-	-	-	-	118,588
12-2023	6,771	2,722	94,380	-	103,873	-	-	-	-	103,873
12-2024	5,831	2,403	82,831	-	91,065	-	-	-	-	91,065
12-2025	4,993	2,104	72,105	-	79,202	-	-	-	-	79,202
12-2026	4,286	1,844	62,829	-	68,959	-	-	-	-	68,959
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	77,320	29,126	1,052,826	-	1,159,272	-	-	-	-	1,159,272
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	77,320	29,126	1,052,826	-	1,159,272	-	-	-	-	1,159,272

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,361	39,754	8,946	-	-	50,061	13,373	13,373	12,751	12,751	7,650
12-2018	1,663	56,013	13,137	-	-	70,813	94,608	107,981	82,004	94,755	56,853
12-2019	1,696	54,648	-	-	-	56,344	114,760	222,741	90,429	185,184	111,111
12-2020	1,690	53,189	-	-	-	54,880	105,067	327,808	75,265	260,449	156,270
12-2021	1,657	52,502	-	-	-	54,159	83,520	411,328	54,391	314,840	188,904
12-2022	1,633	53,333	-	-	-	54,966	63,622	474,950	37,666	352,506	211,503
12-2023	1,616	54,057	-	-	-	55,672	48,201	523,151	25,942	378,448	227,069
12-2024	1,605	56,583	-	-	-	58,188	32,878	556,029	16,086	394,534	236,720
12-2025	1,598	60,689	-	-	-	62,287	16,915	572,944	7,524	402,058	241,235
12-2026	1,597	60,448	-	-	-	62,045	6,914	579,857	2,796	404,853	242,912
12-2027	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2028	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2029	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2030	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2031	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2032	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2033	-	-	-	-	-	-	-	579,857	-	404,853	242,912
12-2034	-	-	-	-	-	-	-	579,857	-	404,853	242,912
S-TOT	16,116	541,216	22,083	-	-	579,415	579,857		404,853		
REM	-	-	-	-	-	-	-	579,857	-	404,853	242,912
TOTAL	16,116	541,216	22,083	-	-	579,415	579,857		404,853		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 2P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	1	109	22	393	30	38	8	137	10	48.18	34.07	5.45
12-2018	1	153	30	530	43	53	10	185	15	48.89	34.57	5.53
12-2019	1	111	21	363	40	39	7	127	14	49.90	35.29	5.65
12-2020	1	82	16	286	-	29	6	100	-	50.89	35.99	5.68
12-2021	1	57	11	194	-	20	4	67	-	51.99	36.77	5.69
12-2022	1	40	8	131	-	14	3	46	-	53.25	37.66	5.69
12-2023	1	28	5	89	-	10	2	31	-	54.32	38.41	5.80
12-2024	1	20	4	61	-	7	1	21	-	55.40	39.18	5.92
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
CUMULATIVE		9,950	-	24,757	-				-			
ULTIMATE		10,551	116	26,805	114				40			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	1,836	256	745	-	2,836	-	-	-	-	2,836
12-2018	2,599	357	1,022	-	3,978	-	-	-	-	3,978
12-2019	1,932	259	715	-	2,906	-	-	-	-	2,906
12-2020	1,453	200	567	-	2,220	-	-	-	-	2,220
12-2021	1,040	141	384	-	1,566	-	-	-	-	1,566
12-2022	749	100	261	-	1,110	-	-	-	-	1,110
12-2023	537	71	180	-	788	-	-	-	-	788
12-2024	386	50	125	-	562	-	-	-	-	562
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	229	480	-	-	-	710	2,127	2,127	2,028	2,028	1,217
12-2018	326	699	-	-	-	1,026	2,953	5,079	2,559	4,587	2,752
12-2019	242	726	-	-	-	969	1,938	7,017	1,527	6,114	3,668
12-2020	182	598	-	-	-	781	1,440	8,456	1,031	7,145	4,287
12-2021	130	627	-	-	-	757	808	9,265	526	7,671	4,603
12-2022	93	397	-	-	-	491	619	9,884	367	8,038	4,823
12-2023	67	422	-	-	-	489	299	10,183	161	8,199	4,919
12-2024	48	413	-	-	-	462	100	10,283	49	8,248	4,949
12-2025	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2026	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2027	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2028	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2029	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2030	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2031	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2032	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2033	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2034	-	-	-	-	-	-	-	10,283	-	8,248	4,949
S-TOT	1,320	4,365	-	-	-	5,684	10,283		8,248		
REM	-	-	-	-	-	-	-	10,283	-	8,248	4,949
TOTAL	1,320	4,365	-	-	-	5,684	10,283		8,248		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - BP NORTH SEA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	24	630	540	35,997	1,926	249	213	16,288	878	53.11	30.33	4.98
12-2018	24	1,301	1,225	93,398	3,285	528	494	43,109	1,524	54.38	29.97	5.02
12-2019	22	1,130	1,130	96,246	3,285	470	465	45,079	1,518	55.83	29.89	5.10
12-2020	18	915	964	85,279	3,294	386	400	40,116	1,546	57.10	30.28	5.12
12-2021	15	700	776	72,459	3,285	300	326	34,296	1,552	58.54	30.62	5.12
12-2022	14	538	623	62,277	3,285	235	265	29,696	1,556	60.18	30.93	5.11
12-2023	11	401	486	53,405	3,285	180	212	25,711	1,558	61.69	30.85	5.19
12-2024	7	305	349	45,076	3,294	141	158	22,036	1,566	63.24	30.07	5.27
12-2025	5	213	243	38,005	3,285	104	117	18,847	1,567	65.26	28.91	5.35
12-2026	5	179	206	33,530	3,285	88	100	16,674	1,570	66.64	29.20	5.45
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	24	6,311	6,540	615,670	31,509	2,680	2,750	291,852	14,834	57.66	30.20	5.15
REM	-	-	-	-	-	-	-	-	-			
TOTAL	24	6,311	6,540	615,670	31,509	2,680	2,750	291,852	14,834	57.66	30.20	5.15
CUMULATIVE		177,212	-	3,459,281	-				-			
ULTIMATE		183,523	6,540	4,074,951	31,509				14,834			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS MMCF M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	13,221	6,456	81,100	-	100,777	-	-	-	-	100,777
12-2018	28,737	14,811	216,579	-	260,127	-	-	-	-	260,127
12-2019	26,248	13,911	229,986	-	270,145	-	-	-	-	270,145
12-2020	22,017	12,112	205,532	-	239,661	-	-	-	-	239,661
12-2021	17,540	9,967	175,675	-	203,183	-	-	-	-	203,183
12-2022	14,137	8,206	151,635	-	173,978	-	-	-	-	173,978
12-2023	11,105	6,530	133,463	-	151,098	-	-	-	-	151,098
12-2024	8,904	4,758	116,053	-	129,715	-	-	-	-	129,715
12-2025	6,785	3,372	100,746	-	110,903	-	-	-	-	110,903
12-2026	5,867	2,921	90,829	-	99,616	-	-	-	-	99,616
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	154,561	83,044	1,501,597	-	1,739,202	-	-	-	-	1,739,202
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	154,561	83,044	1,501,597	-	1,739,202	-	-	-	-	1,739,202

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	2,951	52,704	16,223	-	-	71,878	28,899	28,899	27,554	27,554	16,532
12-2018	4,798	77,559	13,147	-	-	95,504	164,623	193,522	142,693	170,247	102,148
12-2019	4,406	75,334	-	-	-	79,740	190,405	383,927	150,036	320,283	192,170
12-2020	3,949	70,490	-	-	-	74,438	165,223	549,150	118,357	438,641	263,184
12-2021	3,432	68,182	-	-	-	71,614	131,569	680,719	85,681	524,322	314,593
12-2022	3,015	68,153	-	-	-	71,168	102,810	783,529	60,866	585,188	351,113
12-2023	2,635	67,450	-	-	-	70,084	81,014	864,542	43,602	628,790	377,274
12-2024	2,255	67,290	-	-	-	69,545	60,170	924,712	29,440	658,230	394,938
12-2025	1,946	66,186	-	-	-	68,132	42,771	967,483	19,025	677,254	406,352
12-2026	1,898	65,351	-	-	-	67,249	32,367	999,850	13,088	690,342	414,205
12-2027	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2028	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2029	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2030	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2031	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2032	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2033	-	-	-	-	-	-	-	999,850	-	690,342	414,205
12-2034	-	-	-	-	-	-	-	999,850	-	690,342	414,205
S-TOT	31,283	678,699	29,370	-	-	739,352	999,850		690,342		
REM	-	-	-	-	-	-	-	999,850	-	690,342	414,205
TOTAL	31,283	678,699	29,370	-	-	739,352	999,850		690,342		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - BRUCE PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	21	352	383	11,793	577	127	138	4,245	208	52.78	34.07	5.45
12-2018	20	709	811	25,072	802	255	292	9,026	289	53.56	34.57	5.53
12-2019	18	557	687	21,350	845	200	247	7,686	304	54.66	35.29	5.65
12-2020	14	425	567	17,713	721	153	204	6,377	259	55.75	35.99	5.68
12-2021	11	296	433	13,597	643	106	156	4,895	232	56.96	36.77	5.69
12-2022	10	199	322	10,157	621	72	116	3,657	224	58.33	37.66	5.69
12-2023	7	114	220	6,985	602	41	79	2,515	217	59.50	38.41	5.80
12-2024	3	60	111	3,521	581	22	40	1,268	209	60.69	39.18	5.92
12-2025	2	20	35	1,113	541	7	13	401	195	61.91	39.96	6.04
12-2026	2	11	20	648	518	4	7	233	186	63.14	40.76	6.16
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
REM	-	-	-	-	-	-	-	-	-			
TOTAL	21	2,743	3,591	111,949	6,451	988	1,293	40,302	2,322	55.24	35.89	5.64
CUMULATIVE		164,814	-	3,066,209	-				-			
ULTIMATE		167,557	3,591	3,178,158	6,451				2,322			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	6,691	4,698	23,118	-	34,507	-	-	-	-	34,507
12-2018	13,661	10,098	49,946	-	73,705	-	-	-	-	73,705
12-2019	10,957	8,732	43,417	-	63,105	-	-	-	-	63,105
12-2020	8,534	7,352	36,228	-	52,114	-	-	-	-	52,114
12-2021	6,065	5,735	27,865	-	39,665	-	-	-	-	39,665
12-2022	4,187	4,366	20,804	-	29,357	-	-	-	-	29,357
12-2023	2,447	3,038	14,592	-	20,078	-	-	-	-	20,078
12-2024	1,315	1,565	7,504	-	10,384	-	-	-	-	10,384
12-2025	437	505	2,419	-	3,361	-	-	-	-	3,361
12-2026	258	300	1,437	-	1,995	-	-	-	-	1,995
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	54,551	46,389	227,329	-	328,269	-	-	-	-	328,269

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,360	12,470	7,277	-	-	21,107	13,400	13,400	12,776	12,776	7,666
12-2018	2,765	18,201	10	-	-	20,977	52,728	66,128	45,704	58,480	35,088
12-2019	2,385	15,072	-	-	-	17,457	45,649	111,776	35,970	94,450	56,670
12-2020	2,013	12,961	-	-	-	14,974	37,140	148,916	26,605	121,055	72,633
12-2021	1,584	11,299	-	-	-	12,883	26,781	175,698	17,441	138,496	83,098
12-2022	1,226	10,366	-	-	-	11,592	17,765	193,462	10,517	149,013	89,408
12-2023	887	8,669	-	-	-	9,556	10,522	203,985	5,663	154,677	92,806
12-2024	534	6,091	-	-	-	6,624	3,759	207,744	1,839	156,516	93,910
12-2025	279	1,701	-	-	-	1,980	1,381	209,125	614	157,130	94,278
12-2026	232	1,694	-	-	-	1,926	69	209,194	28	157,158	94,295
12-2027	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2028	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2029	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2030	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2031	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2032	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2033	-	-	-	-	-	-	-	209,194	-	157,158	94,295
12-2034	-	-	-	-	-	-	-	209,194	-	157,158	94,295
S-TOT	13,264	98,524	7,287	-	-	119,076	209,194		157,158		
REM	-	-	-	-	-	-	-	209,194	-	157,158	94,295
TOTAL	13,264	98,524	7,287	-	-	119,076	209,194		157,158		

LIFE - 10 years

THESE DATA ARE PART OF A RYDER SCOTT REPORT AND ARE SUBJECT TO THE CONDITIONS IN THE TEXT OF THE REPORT
THESE DATA WERE GENERATED USING THE PALANTIRCASH PROGRAM

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - RHUM PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	2	168	135	23,811	1,319	84	67.46	11,906	659	55.85	22.26	4.81
12-2018	3	440	384	67,796	2,439	220	192	33,898	1,220	56.67	22.72	4.89
12-2019	3	462	421	74,532	2,400	231	211	37,266	1,200	57.84	23.36	4.99
12-2020	3	408	380	67,280	2,573	204	190	33,640	1,287	58.99	23.99	5.02
12-2021	3	346	331	58,668	2,642	173	166	29,334	1,321	60.27	24.69	5.03
12-2022	3	298	293	51,988	2,664	149	147	25,994	1,332	61.72	25.49	5.02
12-2023	3	258	261	46,331	2,683	129	131	23,166	1,342	62.96	26.17	5.12
12-2024	3	224	234	41,494	2,713	112	117	20,747	1,356	64.22	26.86	5.23
12-2025	3	194	208	36,892	2,744	97	104	18,446	1,372	65.50	27.56	5.33
12-2026	3	168	185	32,882	2,767	84	93	16,441	1,384	66.81	28.28	5.44
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	3	2,967	2,833	501,673	24,944	1,483	1,417	250,837	12,472	60.32	24.86	5.06
REM	-	-	-	-	-	-	-	-	-			
TOTAL	3	2,967	2,833	501,673	24,944	1,483	1,417	250,837	12,472	60.32	24.86	5.06
CUMULATIVE		2,448	-	368,315	-				-			
ULTIMATE		5,415	2,833	869,988	24,944				12,472			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	4,694	1,502	57,238	-	63,434	-	-	-	-	63,434
12-2018	12,477	4,356	165,611	-	182,444	-	-	-	-	182,444
12-2019	13,359	4,921	185,854	-	204,133	-	-	-	-	204,133
12-2020	12,029	4,560	168,738	-	185,327	-	-	-	-	185,327
12-2021	10,435	4,091	147,427	-	161,952	-	-	-	-	161,952
12-2022	9,201	3,740	130,570	-	143,511	-	-	-	-	143,511
12-2023	8,121	3,421	118,690	-	130,231	-	-	-	-	130,231
12-2024	7,203	3,143	108,424	-	118,770	-	-	-	-	118,770
12-2025	6,348	2,867	98,327	-	107,542	-	-	-	-	107,542
12-2026	5,609	2,621	89,392	-	97,621	-	-	-	-	97,621
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	89,476	35,220	1,270,270	-	1,394,966	-	-	-	-	1,394,966
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	89,476	35,220	1,270,270	-	1,394,966	-	-	-	-	1,394,966

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	1,361	39,754	8,946	-	-	50,061	13,373	13,373	12,751	12,751	7,650
12-2018	1,706	58,658	13,137	-	-	73,501	108,943	122,316	94,430	107,180	64,308
12-2019	1,778	59,536	-	-	-	61,314	142,819	265,135	112,539	219,720	131,832
12-2020	1,754	56,930	-	-	-	58,684	126,643	391,778	90,721	310,441	186,264
12-2021	1,718	56,256	-	-	-	57,973	103,979	495,757	67,714	378,155	226,893
12-2022	1,696	57,390	-	-	-	59,086	84,426	580,182	49,982	428,137	256,882
12-2023	1,681	58,358	-	-	-	60,039	70,192	650,374	37,778	465,914	279,549
12-2024	1,673	60,786	-	-	-	62,459	56,311	706,685	27,552	493,466	296,080
12-2025	1,667	64,485	-	-	-	66,152	41,390	748,075	18,410	511,876	307,126
12-2026	1,666	63,657	-	-	-	65,322	32,298	780,374	13,060	524,936	314,962
12-2027	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2028	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2029	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2030	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2031	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2032	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2033	-	-	-	-	-	-	-	780,374	-	524,936	314,962
12-2034	-	-	-	-	-	-	-	780,374	-	524,936	314,962
S-TOT	16,699	575,810	22,083	-	-	614,592	780,374		524,936		
REM	-	-	-	-	-	-	-	780,374	-	524,936	314,962
TOTAL	16,699	575,810	22,083	-	-	614,592	780,374		524,936		

LIFE - 10 years

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE FIRM LIC. NO. F-1580

BP EXPLORATION AND PRODUCTION
ESTIMATED FUTURE RESERVES AND INCOME
DERIVED THROUGH CERTAIN INTERESTS
SPE-PRMS (ESCALATED PARAMETERS)
AS OF JUNE 1, 2017
(NO DECOMMISSIONING COSTS)

GRAND SUMMARY - KEITH PROJECT AREA
TOTAL 3P RESERVES SPE-PRMS

		ESTIMATED 8/8ths PRODUCTION				COMPANY NET PRODUCTION				AVERAGE REALIZED PRICE		
MO-YEAR	NO. OF WELLS	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND MBBL	PLANT PRODUCTS MBBL	GAS MMCF	FUEL GAS MMCF	OIL/COND $/BBL	PLANT PRODUCTS $/BBL	SALE GAS $/M
12-2017	1	109	22	393	30	38	8	137	10	48.18	34.07	5.45
12-2018	1	153	30	530	43	53	10	185	15	48.89	34.57	5.53
12-2019	1	111	21	363	40	39	7	127	14	49.90	35.29	5.65
12-2020	1	82	16	286	-	29	6	100	-	50.89	35.99	5.68
12-2021	1	57	11	194	-	20	4	67	-	51.99	36.77	5.69
12-2022	1	40	8	131	-	14	3	46	-	53.25	37.66	5.69
12-2023	1	28	5	89	-	10	2	31	-	54.32	38.41	5.80
12-2024	1	20	4	61	-	7	1	21	-	55.40	39.18	5.92
12-2025	-	-	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-	-	-
S-TOT	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
REM	-	-	-	-	-	-	-	-	-			
TOTAL	1	601	116	2,048	114	209	40	713	40	50.28	35.54	5.61
CUMULATIVE		9,950	-	24,757	-				-			
ULTIMATE		10,551	116	26,805	114				40			

	FUTURE GROSS REVENUE (FGR)					PRODUCTION TAXES				
END MO-YEAR	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	Other M$	TOTAL FGR M$	OIL/COND M$	PLANT PRODUCTS M$	GAS M$	TOTAL TAXES M$	FGR AFTER PRODUCTION DISC CUM M$
12-2017	1,836	256	745	-	2,836	-	-	-	-	2,836
12-2018	2,599	357	1,022	-	3,978	-	-	-	-	3,978
12-2019	1,932	259	715	-	2,906	-	-	-	-	2,906
12-2020	1,453	200	567	-	2,220	-	-	-	-	2,220
12-2021	1,040	141	384	-	1,566	-	-	-	-	1,566
12-2022	749	100	261	-	1,110	-	-	-	-	1,110
12-2023	537	71	180	-	788	-	-	-	-	788
12-2024	386	50	125	-	562	-	-	-	-	562
12-2025	-	-	-	-	-	-	-	-	-	-
12-2026	-	-	-	-	-	-	-	-	-	-
12-2027	-	-	-	-	-	-	-	-	-	-
12-2028	-	-	-	-	-	-	-	-	-	-
12-2029	-	-	-	-	-	-	-	-	-	-
12-2030	-	-	-	-	-	-	-	-	-	-
12-2031	-	-	-	-	-	-	-	-	-	-
12-2032	-	-	-	-	-	-	-	-	-	-
12-2033	-	-	-	-	-	-	-	-	-	-
12-2034	-	-	-	-	-	-	-	-	-	-
S-TOT	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967
REM	-	-	-	-	-	-	-	-	-	-
TOTAL	10,534	1,435	3,999	-	15,967	-	-	-	-	15,967

	DEDUCTIONS						FUTURE NET INCOME BEFORE INCOME TAXES				AFTER TAX
							UNDISCOUNTED		DISCOUNTED		DISCOUNTED
END MO-YEAR	TARIFFS & LICENSES M$	OPERATING COSTS M$	DEVELOPMENT COSTS M$	DECOMM. M$	OTHER M$	TOTAL M$	ANNUAL FNI M$	CUM UND M$	FNI @ 10% M$	CUM FNI @ 10% M$	CUM FNI AT@ M$
12-2017	229	480	-	-	-	710	2,127	2,127	2,028	2,028	1,217
12-2018	326	699	-	-	-	1,026	2,953	5,079	2,559	4,587	2,752
12-2019	242	726	-	-	-	969	1,938	7,017	1,527	6,114	3,668
12-2020	182	598	-	-	-	781	1,440	8,456	1,031	7,145	4,287
12-2021	130	627	-	-	-	757	808	9,265	526	7,671	4,603
12-2022	93	397	-	-	-	491	619	9,884	367	8,038	4,823
12-2023	67	422	-	-	-	489	299	10,183	161	8,199	4,919
12-2024	48	413	-	-	-	462	100	10,283	49	8,248	4,949
12-2025	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2026	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2027	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2028	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2029	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2030	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2031	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2032	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2033	-	-	-	-	-	-	-	10,283	-	8,248	4,949
12-2034	-	-	-	-	-	-	-	10,283	-	8,248	4,949
S-TOT	1,320	4,365	-	-	-	5,684	10,283		8,248		
REM	-	-	-	-	-	-	-	10,283	-	8,248	4,949
TOTAL	1,320	4,365	-	-	-	5,684	10,283		8,248		

LIFE - 10 years

ESTIMATES

of

RESERVES AND FUTURE REVENUE AND UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES

to the

SERICA ENERGY PLC INTEREST

in

CERTAIN OIL AND GAS PROPERTIES

located in

IRISH WATERS IN THE ATLANTIC OCEAN

and in the

UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

as of

JUNE 30, 2017

BASED ON ESCALATED PRICE AND COST PARAMETERS

specified by

SERICA ENERGY PLC

NSAI
NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY
GEOPHYSICS • PETROPHYSICS

November 20, 2017

Serica Energy plc 52 George Street London W1U 7EA United Kingdom	Peel Hunt LLP 120 London Wall London EC2Y 5ET United Kingdom

Ladies and Gentlemen:

In accordance with the request of Serica Energy plc (Serica), we have estimated the proved developed producing, probable, and possible reserves and future revenue, as of June 30, 2017, to the Serica interest in certain gas properties located in Erskine Field, United Kingdom (UK) Sector of the Central North Sea. Also as requested, we have estimated the unrisked contingent and prospective resources, as of June 30, 2017, to the Serica interest in certain discoveries and prospects located in Irish waters in the Atlantic Ocean and the UK Sector of the Central North Sea. It is our understanding that Serica Energy Slyne B.V. and Serica Energy (UK) Limited own the interests in these properties and are wholly owned subsidiaries of Serica. We completed our evaluation on or about the date of this letter. For the reserves, this Competent Person's Report (report) has been prepared using price and cost parameters specified by Serica, referred to as the Base Price Case, as discussed in subsequent paragraphs of this letter. Gross volumes shown in this report are 100 percent of the volumes expected to be produced from the properties.

We have been informed by Serica that it proposes through its wholly owned subsidiary Serica Energy (UK) Limited to acquire the Bruce, Keith, and Rhum Fields (BKR Assets) from BP Exploration Operating Company Limited (BP). We have also been informed by Serica that the proposed acquisition will constitute a reverse takeover of Serica under the AIM Rules for Companies and will be conditional, among other things, upon the approval of Serica's shareholders. As part of the process, we have been informed by Serica that Serica as enlarged by the acquisition of the BKR Assets, will need to seek readmission of its shares to trading on the AIM market of the London Stock Exchange (Readmission). We understand that this report will be included in the new Admission Document in connection with Readmission.

This report has been prepared in accordance with the AIM Rules for Companies, specifically the "Note for Mining, Oil and Gas Companies - June 2009" (Note for Mining, Oil and Gas Companies) and the content requirements at Appendix 2 and the summaries set out in Appendices 1 and 3, as well as the definitions and guidelines set forth in the 2007 Petroleum Resources Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). As presented in the 2007 PRMS, petroleum accumulations can be classified, in decreasing order of likelihood of commerciality, as reserves, contingent resources, or prospective resources. Different classifications of petroleum accumulations have varying degrees of technical and commercial risk that are difficult to quantify; thus reserves, contingent resources, and prospective resources should not be aggregated without extensive consideration of these factors. Definitions are presented immediately following this letter. Following the definitions are a list of abbreviations used in this report and the certificates of qualification for the evaluators who contributed to this report.

RESERVES

Reserves are those quantities of petroleum anticipated to be commercially recoverable from known accumulations by application of development projects from a given date forward under defined conditions. Reserves must be discovered, recoverable, commercial, and remaining as of the evaluation date based on the planned development projects to be applied. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be commercially recoverable; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves.

As presented in the accompanying summary projections, Tables I through V, and the revenues, costs, and taxes in Table VI, we estimate the gross and net reserves and future net revenue to the Serica interest in Erskine Field, as of June 30, 2017, to be:

Category	Gross Reserves Oil (MBBL)	Gross Reserves Gas (MMCF)	Net Reserves Oil (MBBL)	Net Reserves NGL (MBBL)	Net Reserves Gas (MMCF)	Future Net Revenue After Income Taxes (M$) Total	Future Net Revenue After Income Taxes (M$) Present Worth at 10%
Proved Developed Producing	4,559.3	30,696.1	820.7	107.6	5,414.8	41,070.8	37,281.9
Probable	3,765.5	25,004.0	677.8	87.7	4,410.7	39,267.6	31,070.1
Proved + Probable (2P)	8,324.8	55,700.1	1,498.5	195.3	9,825.5	80,338.5	68,352.0
Possible	4,581.2	30,263.2	824.6	106.1	5,338.4	59,068.2	43,436.9
Proved + Probable + Possible (3P)	12,906.0	85,963.3	2,323.1	301.3	15,163.9	139,406.7	111,789.0

Totals may not add because of rounding.

The oil volumes shown include condensate only. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$) using the October 13, 2017, United States Federal Reserve exchange rate of $1.3304 per British pound sterling.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether proved developed non-producing or proved undeveloped reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue for the reserves shown in this report is Serica's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Serica's share of capital costs, abandonment and reclamation costs, operating expenses, and estimates of the UK's corporate income taxes. An effective tax rate of 40 percent, composed of a 30 percent UK Ring Fence Corporation Tax and a 10 percent Supplementary Charge, was applied to future net revenue in excess of Serica's loss carry-forward pool of MM$151. The tax estimates are a simplification of current tax law and were not prepared by a tax accountant or lawyer. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

As requested, this report has been prepared using Base Price Case oil, NGL, and gas price parameters specified by Serica. Oil and NGL prices are based on Brent futures prices and are adjusted for quality, transportation fees, and market differentials. Gas prices are based on National Balancing Point futures prices and are adjusted for energy content, transportation fees, and market differentials. Sensitivities using Low and High Price Cases are further detailed in the technical discussion that follows this letter. Annual average prices for the Base Price Case, before adjustments, are shown in the following table:

Period Ending	Oil/ NGL Price ($/Barrel)	Gas Price (Pence/ therm)	Gas Price ($/MMBTU)
12-31-2017	53.63	47.7	6.346
12-31-2018	53.68	46.6	6.202
12-31-2019	54.09	45.6	6.069
12-31-2020	65.00	50.0	6.652
12-31-2021	70.00	50.0	6.652
12-31-2022	75.00	50.0	6.652
12-31-2023	75.00	55.0	7.317

Thereafter escalated 2.5 percent
on January 1 of each year.

Operating costs used in this report are based on operating expense records of Serica. These costs include the overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the field level. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs. Erskine Field produces to the Lomond Platform, and Serica's share of the operating costs for the platform are based on a cost-sharing agreement between the field's owners and other producers to the platform. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. As requested, operating costs are escalated 2.5 percent on January 1 of each year throughout the lives of the properties.

Capital costs used in this report were provided by Serica and are based on authorizations for expenditure and actual costs from recent activity. Capital costs are included as required for facilities maintenance. Based on our review of the records provided to us, we regard these estimated capital costs to be reasonable. Abandonment and reclamation costs used in this report are Serica's estimates of reclamation costs and the costs to abandon the wells, platform, and production facilities, net of any salvage value. It is our understanding that, pursuant to the sales agreement Serica entered into when it purchased its interest in Erskine Field, it is not liable for abandonment costs up to a maximum value that exceeds its current estimates of abandonment costs. As requested, capital costs are escalated 2.5 percent on January 1 of each year throughout the lives of the properties.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Serica interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Serica receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The contingent resources shown in this report subclassified as development pending are contingent upon finalization and approval of a development plan and commitment from the owners to develop the field. The contingent resources shown in this report subclassified as development not viable are contingent upon acquisition of additional technical data that demonstrate producing rates and volumes sufficient to sustain economic viability, generation and approval of a development plan, and commitment from the owners to develop the discoveries. This report does not include economic analysis for these properties. Based on analogous field developments, it appears that the best estimate development pending contingent resources in this report have a reasonable chance of being economically viable. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed.

Development Pending

The contingent resources in Columbus Field have been subclassified as development pending, which are those resources from a discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. We estimate the gross and working interest unrisked development pending contingent resources to the Serica interest in Columbus Field, along with the risk factor, as of June 30, 2017, to be:

	Unrisked Development Pending Contingent Resources				
	Gross		Working Interest		Risk
Region/Area/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Factor[1] (%)
UK Sector of the Central North Sea					
Columbus Field					
Low Estimate (1C)	1,269.2	28,857.3	634.6	14,428.7	85
Best Estimate (2C)	2,793.7	63,533.2	1,396.9	31,766.6	85
High Estimate (3C)	3,636.2	82,284.1	1,818.1	41,142.1	85

(1) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

The oil volumes shown include condensate only.

Development Not Viable

The contingent resources in Bandon Discovery have been subclassified as development not viable, which are those resources from a discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential. We estimate the gross and working interest unrisked development not viable contingent resources to the Serica interest in Bandon Discovery, along with the risk factor, as of June 30, 2017, to be:

	Unrisked Development Not Viable Contingent Resources				
	Gross		Working Interest		Risk
Region/Area/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Factor[1] (%)
Irish Waters in the Atlantic Ocean					
Bandon Discovery					
Low Estimate (1C)	0.0	0.0	0.0	0.0	0
Best Estimate (2C)	0.0	0.0	0.0	0.0	0
High Estimate (3C)	0.0	0.0	0.0	0.0	0

(1) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

The oil volumes shown include condensate only.

All Contingent Resources

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively. The estimates of contingent resources included herein have not been adjusted for development risk.

Unrisked contingent resources are estimated ranges of discovered and recoverable oil and gas volumes assuming their development and are based on estimated ranges of discovered in-place volumes. For resources, the chance of commerciality includes both the chance of discovery, and, once a discovery is made, the chance of development. For contingent resources, given that a discovery has been made, the chance of commerciality is equal to the chance of development. We have estimated the chance of development, to account for the possibility that the contingencies are not successfully addressed. Such risking assesses whether the project contingencies can be successfully addressed and includes assessment of the following criteria: (1) the expected timetable for development; (2) the economics of the project; (3) the marketability of the oil and gas production; (4) the availability of infrastructure and technology; (5) the political, regulatory, and environmental conditions; (6) the project maturity and definition; (7) the availability of capital; and, ultimately, (8) the expectation that the operator will undertake development. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

We estimate the gross and working interest unrisked prospective resources to the Serica interest in these properties, along with the risk factor, as of June 30, 2017, to be:

	Unrisked Prospective Resources(1)				
	Gross		Working Interest		Risk
Region/Prospect/Category	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Factor(2) (%)
Irish Waters in the Atlantic Ocean					
Achill					
Low Estimate	0.0	120.7	0.0	120.7	26
Best Estimate	0.0	252.7	0.0	252.7	26
High Estimate	0.0	516.5	0.0	516.5	26
Bandon South					
Low Estimate	0.0	6.7	0.0	6.7	26
Best Estimate	0.0	26.9	0.0	26.9	26
High Estimate	0.0	101.7	0.0	101.7	26
Boyne Sherwood					
Low Estimate	0.0	60.8	0.0	60.8	26
Best Estimate	0.0	180.2	0.0	180.2	26
High Estimate	0.0	528.5	0.0	528.5	26
Boyne Suisnish					
Low Estimate	5.6	1.4	5.6	1.4	20
Best Estimate	20.1	5.5	20.1	5.5	20
High Estimate	76.7	22.1	76.7	22.1	20
Liffey Sherwood					
Low Estimate	0.0	52.6	0.0	52.6	26
Best Estimate	0.0	180.4	0.0	180.4	26
High Estimate	0.0	626.7	0.0	626.7	26
Liffey Suisnish					
Low Estimate	30.3	7.6	30.3	7.6	20
Best Estimate	128.2	34.0	128.2	34.0	20
High Estimate	526.7	147.4	526.7	147.4	20
UK Sector of the Central North Sea					
Rowallan Pentland					
Low Estimate	3.5	54.4	0.5	8.2	22
Best Estimate	8.8	118.7	1.3	17.8	22
High Estimate	20.0	259.9	3.0	39.0	22

Region/Prospect/Category	Unrisked Prospective Resources[1] Gross Oil (MMBBL)	Gross Gas (BCF)	Working Interest Oil (MMBBL)	Working Interest Gas (BCF)	Risk Factor[2] (%)
UK Sector of the Central North Sea (continued)					
Rowallan Triassic					
Low Estimate	10.0	134.1	1.5	20.1	22
Best Estimate	33.0	422.4	4.9	63.4	22
High Estimate	113.4	1,463.9	17.0	219.6	22
Total					
Low Estimate	49.4	438.3	37.9	278.1	-
Best Estimate	190.0	1,220.9	154.6	760.8	-
High Estimate	736.9	3,666.7	623.4	2,201.5	-

Notes: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

[1] These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

[2] The risk factor for prospective resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of discovery".

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

The prospective resources shown in this report have been estimated using probabilistic methods and are dependent on a petroleum discovery being made. If a discovery is made and development is undertaken, the probability that the recoverable volumes will equal or exceed the unrisked estimated amounts is 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. As recommended in the PRMS, the low, best, and high estimate prospective resources have been aggregated beyond the prospect level by arithmetic summation; therefore, these totals do not include the portfolio effect that might result from statistical aggregation.

Unrisked prospective resources are estimated ranges of recoverable oil and gas volumes assuming their discovery and development and are based on estimated ranges of undiscovered in-place volumes. Geologic risking of prospective resources addresses the probability of success for the discovery of a significant quantity of potentially moveable petroleum; this risk analysis is conducted independent of estimations of petroleum volumes. Principal geologic risk elements of the petroleum system include (1) trap and seal characteristics; (2) reservoir presence and quality; (3) source rock capacity, quality, and maturity; and (4) timing, migration, and preservation of petroleum in relation to trap and seal formation. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation. Included in this report is a discussion of the primary geologic risk elements for each prospect.

Each prospect was evaluated to determine ranges of in-place and recoverable petroleum and was risked as an independent entity without dependency between potential prospect drilling outcomes. If petroleum discoveries are made, smaller-volume prospects may not be commercial to independently develop, although they may become candidates for satellite developments and tie-backs to existing infrastructure at some future date. The development infrastructure and data obtained from early discoveries will alter both geologic risk and future economics of subsequent discoveries and developments.

It should be understood that the prospective resources discussed and shown herein are those undiscovered, highly speculative resources estimated beyond reserves or contingent resources where geological and geophysical data suggest the potential for discovery of petroleum but where the level of proof is insufficient for classification as reserves or contingent resources. The unrisked prospective resources shown in this report are the range of volumes that could reasonably be expected to be recovered in the event of the discovery and development of these prospects. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of discovery".

GENERAL INFORMATION

As shown in the Table of Contents, this report includes, for Erskine Field, summary projections of reserves and revenue by reserves category as well as a table of revenue, taxes, and costs. Also included are a technical discussion and pertinent figures for all properties in this report.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

The reserves, contingent resources, and prospective resources shown in this report are estimates only and should not be construed as exact quantities. Estimates may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Serica, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the volumes, and that our projections of future production will prove consistent with actual performance. If these volumes are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received, and costs incurred may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 PRMS definitions and guidelines. The contingent and prospective resources shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Serica, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. and were accepted as accurate. Supporting work data are on file in our office and are available for examination in our offices by parties with written authorization from Serica. We have not examined the contractual rights to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Netherland, Sewell & Associates, Inc. (NSAI) served as independent evaluator in the conduct and analyses described and in the determination of professional opinions expressed herein. NSAI is professionally qualified and a member in good standing of an appropriate, recognized professional association under the AIM Rules for Companies with at least 5 years relevant experience in the estimation, assessment, and evaluation of oil and gas.

NSAI and its management and staff are independent of Serica and have no interest in any assets or share capital of Serica or in the promotion of Serica. Neither NSAI nor its staff will receive any pecuniary or other benefits in connection with this assignment other than a normal fixed consultancy fee, and no part of the fee is linked to Readmission or the value of Serica following the acquisition of the BKR Assets.

NSAI confirms that, to the best of its knowledge, there has been no material change in the information contained in this report since June 30, 2017, being the date to which we have estimated the reserves and resources contained in the report. This report was prepared for Serica and Peel Hunt LLP (in its capacity as nominated adviser to Serica) and should not be used for purposes other than those for which it is intended without our prior written consent.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ Derek F. Newton
Derek F. Newton, P.E. 97689
Senior Vice President

Date Signed: November 20, 2017

By: /s/ Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: November 20, 2017

JMM:DMN

PETROLEUM RESERVES AND RESOURCES CLASSIFICATION AND DEFINITIONS

Excerpted from the Petroleum Resources Management System Approved by
the Society of Petroleum Engineers (SPE) Board of Directors, March 2007

This document contains information excerpted from definitions and guidelines prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE).

Preamble

Petroleum resources are the estimated quantities of hydrocarbons naturally occurring on or within the Earth's crust. Resource assessments estimate total quantities in known and yet-to-be-discovered accumulations; resources evaluations are focused on those quantities that can potentially be recovered and marketed by commercial projects. A petroleum resources management system provides a consistent approach to estimating petroleum quantities, evaluating development projects, and presenting results within a comprehensive classification framework.

These definitions and guidelines are designed to provide a common reference for the international petroleum industry, including national reporting and regulatory disclosure agencies, and to support petroleum project and portfolio management requirements. They are intended to improve clarity in global communications regarding petroleum resources. It is expected that this document will be supplemented with industry education programs and application guides addressing their implementation in a wide spectrum of technical and/or commercial settings.

It is understood that these definitions and guidelines allow flexibility for users and agencies to tailor application for their particular needs; however, any modifications to the guidance contained herein should be clearly identified. The definitions and guidelines contained in this document must not be construed as modifying the interpretation or application of any existing regulatory reporting requirements.

1.0 Basic Principles and Definitions

The estimation of petroleum resource quantities involves the interpretation of volumes and values that have an inherent degree of uncertainty. These quantities are associated with development projects at various stages of design and implementation. Use of a consistent classification system enhances comparisons between projects, groups of projects, and total company portfolios according to forecast production profiles and recoveries. Such a system must consider both technical and commercial factors that impact the project's economic feasibility, its productive life, and its related cash flows.

1.1 Petroleum Resources Classification Framework

Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid phase. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide and sulfur. In rare cases, non-hydrocarbon content could be greater than 50%.

The term "resources" as used herein is intended to encompass all quantities of petroleum naturally occurring on or within the Earth's crust, discovered and undiscovered (recoverable and unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered "conventional" or "unconventional."

Figure 1-1 is a graphical representation of the SPE/WPC/AAPG/SPEE resources classification system. The system defines the major recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable petroleum.

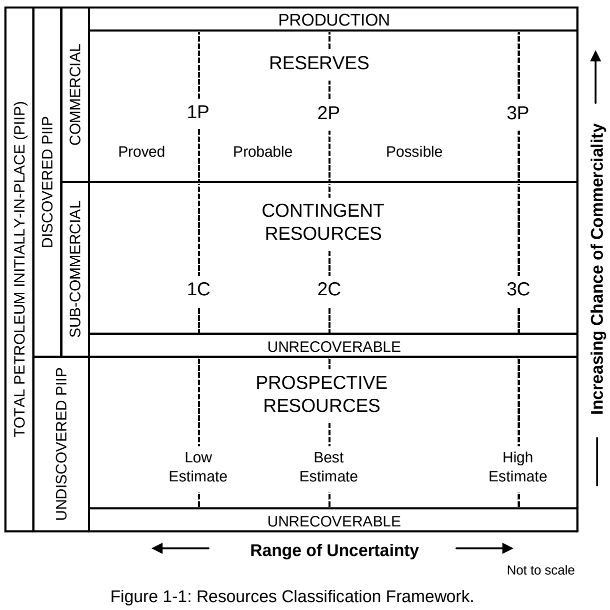

Figure 1-1: Resources Classification Framework.

The "Range of Uncertainty" reflects a range of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the "Chance of

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Commerciality", that is, the chance that the project that will be developed and reach commercial producing status. The following definitions apply to the major subdivisions within the resources classification:

TOTAL PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

DISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.

PRODUCTION is the cumulative quantity of petroleum that has been recovered at a given date. While all recoverable resources are estimated and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Production Measurement, section 3.2).

Multiple development projects may be applied to each known accumulation, and each project will recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into Commercial and Sub-Commercial, with the estimated recoverable quantities being classified as Reserves and Contingent Resources respectively, as defined below.

RESERVES are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

CONTINGENT RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

PROSPECTIVE RESOURCES are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

UNRECOVERABLE is that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Estimated Ultimate Recovery (EUR) is not a resources category, but a term that may be applied to any accumulation or group of accumulations (discovered or undiscovered) to define those quantities of petroleum estimated, as of a given date, to be potentially recoverable under defined technical and commercial conditions plus those quantities already produced (total of recoverable resources).

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1.2 Project-Based Resources Evaluations

The resources evaluation process consists of identifying a recovery project, or projects, associated with a petroleum accumulation(s), estimating the quantities of Petroleum Initially-in-Place, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on its maturity status or chance of commerciality.

This concept of a project-based classification system is further clarified by examining the primary data sources contributing to an evaluation of net recoverable resources (see Figure 1-2) that may be described as follows:

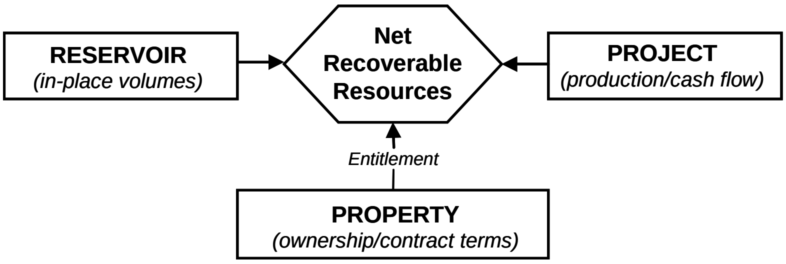

Figure 1-2: Resources Evaluation Data Sources.

- The Reservoir (accumulation): Key attributes include the types and quantities of Petroleum Initially-in-Place and the fluid and rock properties that affect petroleum recovery.

- The Project: Each project applied to a specific reservoir development generates a unique production and cash flow schedule. The time integration of these schedules taken to the project's technical, economic, or contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to Total Initially-in-Place quantities defines the ultimate recovery efficiency for the development project(s). A project may be defined at various levels and stages of maturity; it may include one or many wells and associated production and processing facilities. One project may develop many reservoirs, or many projects may be applied to one reservoir.

- The Property (lease or license area): Each property may have unique associated contractual rights and obligations including the fiscal terms. Such information allows definition of each participant's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations.

In context of this data relationship, "project" is the primary element considered in this resources classification, and net recoverable resources are the incremental quantities derived from each project. Project represents the link between the petroleum accumulation and the decision-making process. A project may, for example, constitute the development of a single reservoir or field, or an incremental development for a producing field, or the integrated development of several fields and associated facilities with a common ownership. In general, an individual project will represent the level at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for that project.

An accumulation or potential accumulation of petroleum may be subject to several separate and distinct projects that are at different stages of exploration or development. Thus, an accumulation may have recoverable quantities in several resource classes simultaneously.

In order to assign recoverable resources of any class, a development plan needs to be defined consisting of one or more projects. Even for Prospective Resources, the estimates of recoverable quantities must be stated in terms of the sales products derived from a development program assuming successful discovery and commercial development. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be largely based on analogous projects. In-place quantities for which a feasible project cannot be defined using current, or reasonably forecast improvements in, technology are classified as Unrecoverable.

Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on a forecast of the conditions that will exist during the time period encompassed by the project's activities (see

Commercial Evaluations, section 3.1). "Conditions" include technological, economic, legal, environmental, social, and governmental factors. While economic factors can be summarized as forecast costs and product prices, the underlying influences include, but are not limited to, market conditions, transportation and processing infrastructure, fiscal terms, and taxes.

The resource quantities being estimated are those volumes producible from a project as measured according to delivery specifications at the point of sale or custody transfer (see Reference Point, section 3.2.1). The cumulative production from the evaluation date forward to cessation of production is the remaining recoverable quantity. The sum of the associated annual net cash flows yields the estimated future net revenue. When the cash flows are discounted according to a defined discount rate and time period, the summation of the discounted cash flows is termed net present value (NPV) of the project (see Evaluation and Reporting Guidelines, section 3.0).

The supporting data, analytical processes, and assumptions used in an evaluation should be documented in sufficient detail to allow an independent evaluator or auditor to clearly understand the basis for estimation and categorization of recoverable quantities and their classification.

2.0 Classification and Categorization Guidelines

2.1 Resources Classification

The basic classification requires establishment of criteria for a petroleum discovery and thereafter the distinction between commercial and sub-commercial projects in known accumulations (and hence between Reserves and Contingent Resources).

2.1.1 Determination of Discovery Status

A discovery is one petroleum accumulation, or several petroleum accumulations collectively, for which one or several exploratory wells have established through testing, sampling, and/or logging the existence of a significant quantity of potentially moveable hydrocarbons.

In this context, "significant" implies that there is evidence of a sufficient quantity of petroleum to justify estimating the in-place volume demonstrated by the well(s) and for evaluating the potential for economic recovery. Estimated recoverable quantities within such a discovered (known) accumulation(s) shall initially be classified as Contingent Resources pending definition of projects with sufficient chance of commercial development to reclassify all, or a portion, as Reserves. Where in-place hydrocarbons are identified but are not considered currently recoverable, such quantities may be classified as Discovered Unrecoverable, if considered appropriate for resource management purposes; a portion of these quantities may become recoverable resources in the future as commercial circumstances change or technological developments occur.

2.1.2 Determination of Commerciality

Discovered recoverable volumes (Contingent Resources) may be considered commercially producible, and thus Reserves, if the entity claiming commerciality has demonstrated firm intention to proceed with development and such intention is based upon all of the following criteria:

- Evidence to support a reasonable timetable for development.
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria.
- A reasonable expectation that there will be a market for all or at least the expected sales quantities of production required to justify development.
- Evidence that the necessary production and transportation facilities are available or can be made available.
- Evidence that legal, contractual, environmental and other social and economic concerns will allow for the actual implementation of the recovery project being evaluated.

To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

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To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that 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.

2.2 Resources Categorization

The horizontal axis in the Resources Classification (Figure 1.1) defines the range of uncertainty in estimates of the quantities of recoverable, or potentially recoverable, petroleum associated with a project. These estimates include both technical and commercial uncertainty components as follows:

- The total petroleum remaining within the accumulation (in-place resources).
- That portion of the in-place petroleum that can be recovered by applying a defined development project or projects.
- Variations in the commercial conditions that may impact the quantities recovered and sold (e.g., market availability, contractual changes).

Where commercial uncertainties are such that there is significant risk that the complete project (as initially defined) will not proceed, it is advised to create a separate project classified as Contingent Resources with an appropriate chance of commerciality.

2.2.1 Range of Uncertainty

The range of uncertainty of the recoverable and/or potentially recoverable volumes may be represented by either deterministic scenarios or by a probability distribution (see Deterministic and Probabilistic Methods, section 4.2).

When the range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that:

- There should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate.
- There should be at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate.
- There should be at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

When using the deterministic scenario method, typically there should also be low, best, and high estimates, where such estimates are based on qualitative assessments of relative uncertainty using consistent interpretation guidelines. Under the deterministic incremental (risk-based) approach, quantities at each level of uncertainty are estimated discretely and separately (see Category Definitions and Guidelines, section 2.2.2).

These same approaches to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources. While there may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production, it is useful to consider the range of potentially recoverable quantities independently of such a risk or consideration of the resource class to which the quantities will be assigned.

2.2.2 Category Definitions and Guidelines

Evaluators may assess recoverable quantities and categorize results by uncertainty using the deterministic incremental (risk-based) approach, the deterministic scenario (cumulative) approach, or probabilistic methods (see "2001 Supplemental Guidelines," Chapter 2.5). In many cases, a combination of approaches is used.

Use of consistent terminology (Figure 1.1) promotes clarity in communication of evaluation results. For Reserves, the general cumulative terms low/best/high estimates are denoted as 1P/2P/3P, respectively. The associated incremental quantities are termed Proved, Probable and Possible. Reserves are a subset of, and must be viewed within context of, the complete resources classification system. While the categorization criteria are proposed specifically for Reserves, in most cases, they can be equally applied to Contingent and Prospective Resources conditional upon their satisfying the criteria for discovery and/or development.

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For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Without new technical information, there should be no change in the distribution of technically recoverable volumes and their categorization boundaries when conditions are satisfied sufficiently to reclassify a project from Contingent Resources to Reserves. All evaluations require application of a consistent set of forecast conditions, including assumed future costs and prices, for both classification of projects and categorization of estimated quantities recovered by each project (see Commercial Evaluations, section 3.1).

Based on additional data and updated interpretations that indicate increased certainty, portions of Possible and Probable Reserves may be re-categorized as Probable and Proved Reserves.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative result, the "best estimate" is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see "2001 Supplemental Guidelines," Chapter 2.5).

Table 1: Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	**Definition**	**Guidelines**
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame. A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that 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.
On Production	The development project is currently producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

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Class/Sub-Class	**Definition**	**Guidelines**
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	In order to move to this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regulatory approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class). The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g. drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time frame. Note that disappointing appraisal/evaluation results could lead to a re-classification of the project to "On Hold" or "Not Viable" status. The project "decision gate" is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.
Development Unclarified or on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are on hold pending the removal of significant contingencies external to the project, or substantial further appraisal/evaluation activities are required to clarify the potential for eventual commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a reasonable expectation that a critical contingency can be removed in the foreseeable future, for example, could lead to a reclassification of the project to "Not Viable" status. The project "decision gate" is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

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Class/Sub-Class	Definition	Guidelines
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project "decision gate" is the decision not to undertake any further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to their chance of discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation in order to be classified as a prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the lead can be matured into a prospect. Such evaluation includes the assessment of the chance of discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but which requires more data acquisition and/or evaluation in order to define specific leads or prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific leads or prospects for more detailed analysis of their chance of discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2: Reserves Status Definitions and Guidelines

Status	Definition	Guidelines
Developed Reserves	Developed Reserves are expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.
Developed Producing Reserves	Developed Producing Reserves are expected to be recovered from completion intervals that 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.
Developed Non-Producing Reserves	Developed Non-Producing Reserves 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 yet 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 require additional completion work or future re-completion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

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Status	Definition	Guidelines
Undeveloped Reserves	Undeveloped Reserves are quantities expected to be recovered through future investments:	(1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3: Reserves Category Definitions and Guidelines

Category	Definition	Guidelines
Proved Reserves	Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.	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. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplemental Guidelines," Chapter 8). Reserves in undeveloped locations may be classified as Proved provided that: • The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially productive. • Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

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Category	Definition	Guidelines
Possible Reserves	Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of commercial production from the reservoir by a defined project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	(See above for separate criteria for Probable Reserves and Possible Reserves.)	The 2P and 3P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

The 2007 Petroleum Resources Management System can be viewed in its entirety at http://www.spe.org/spe-app/spe/industry/reserves/prms.htm.

ABBREVIATIONS

$	United States dollars
°F	degrees Fahrenheit
1C	low estimate scenario of contingent resources
2C	best estimate scenario of contingent resources
3C	high estimate scenario of contingent resources
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
API	American Petroleum Institute
BCF	billions of cubic feet
BKR Assets	Bruce, Keith, and Rhum Fields
cp	centipoise
DST	drillstem test
FEL	Frontier Exploration License
ft	feet
GDT	gas down to
GWC	gas-water contact
km	kilometers
km^2	square kilometers
m	meters
M$	thousands of United States dollars
Ma	Millions of years ago
MM$	millions of United States dollars
MBBL	thousands of barrels
MDT	modular dynamics test
MMBBL	millions of barrels
MMBTU	millions of British thermal units
MMCF	millions of cubic feet
MMCFD	millions of cubic feet of gas per day
MTR	meters
NGL	natural gas liquids
Note for Mining, Oil and Gas Companies	Note for Mining, Oil and Gas Companies – June 2009
NSAI	Netherland, Sewell & Associates, Inc.
OOIP	original oil-in-place
P_g	chance of discovery
PRMS	Petroleum Resources Management System
psia	pounds per square inch absolute
Readmission	Readmission of Serica's shares to trading on the AIM Market of the London Stock Exchange
Report	Competent Person's Report
Serica	Serica Energy plc
SPE	Society of Petroleum Engineers
SPE Standards	Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE
TVDSS	true vertical depth subsea
UK	United Kingdom

CERTIFICATE OF QUALIFICATION

I, Derek F. Newton, Licensed Professional Engineer, 1301 McKinney Street, Suite 3200, Houston, Texas, 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Serica Energy plc (referred to herein as "Serica"). The effective date of this evaluation is June 30, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Serica or its affiliated companies.

I attended Strathclyde University in Scotland, and I graduated in 1986 with a Masters of Science Degree in Petroleum Engineering; I attended University College in Cardiff, Wales, and I graduated in 1983 with a Bachelor of Science Degree in Mechanical Engineering; I am a Licensed Professional Engineer in the State of Texas, United States of America; and I have in excess of 30 years of experience in petroleum engineering studies and evaluations.

A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information or records, the files from Serica, and the appropriate provincial regulatory authorities.

/s/ Derek F. Newton

By: ______________________________

Derek F. Newton, P.E.
Senior Vice President
Texas Registration No. 97689

November 20, 2017
Houston, Texas

CERTIFICATE OF QUALIFICATION

I, Edward C. Roy III, Licensed Professional Geoscientist, 1301 McKinney Street, Suite 3200, Houston, Texas 77010, hereby certify:

I am an employee of Netherland, Sewell & Associates, Inc., which prepared a detailed analysis of certain oil and gas properties of Serica Energy plc (referred to herein as "Serica"). The effective date of this evaluation is June 30, 2017.

I do not have, nor do I expect to receive, any direct or indirect interest in the securities of Serica or its affiliated companies.

I attended Texas A&M University, and I graduated in 1998 with a Master of Science Degree in Geology. I attended Texas Christian University, and I graduated in 1992 with a Bachelor of Science Degree in Geology; I am a Licensed Professional Geoscientist in the State of Texas, United States of America; and I have in excess of 20 years of experience in geological and geophysical studies and evaluations.

A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of the information available from public information or records, the files from Serica, and the appropriate provincial regulatory authorities.

/s/ Edward C. Roy III

By: ____

Edward C. Roy III, P.G.
Vice President
Texas License No. 2364

November 20, 2017
Houston, Texas

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

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SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,104.5	0.0	7,391.0	198.8	25.9	1,303.8	52.44	40.76	6.079	10,426.4	1,056.0	7,925.1	19,407.6
12-31-2018	1,640.6	0.0	11,045.6	295.3	38.7	1,948.5	52.48	40.78	5.966	15,496.4	1,579.2	11,623.7	28,699.3
12-31-2019	1,087.7	0.0	7,343.8	195.8	25.7	1,295.4	52.89	41.10	5.820	10,354.4	1,058.0	7,539.4	18,951.7
12-31-2020	600.7	0.0	4,028.1	108.1	14.1	710.6	63.81	49.40	6.432	6,899.6	697.6	4,570.1	12,167.2
05-31-2021	125.7	0.0	887.6	22.6	3.1	156.6	68.81	53.20	6.432	1,557.1	165.5	1,007.0	2,729.6
SUBTOTAL	4,559.3	0.0	30,696.1	820.7	107.6	5,414.8	54.51	42.34	6.033	44,733.9	4,556.2	32,665.3	81,955.5
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,559.3	0.0	30,696.1	820.7	107.6	5,414.8	54.51	42.34	6.033	44,733.9	4,556.2	32,665.3	81,955.5
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	67,615.1	0.0	361,784.9										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	5,944.2	12,952.7	12,952.7	12,658.0
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	10,931.7	17,082.7	30,035.5	28,282.5
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	10,305.0	7,944.7	37,980.1	34,915.7
12-31-2020	4	0.7	0.0	0.0	719.6	0.0	8,554.2	2,893.3	40,873.4	37,142.5
05-31-2021	2	0.4	0.0	0.0	307.3	0.0	2,224.8	197.4	41,070.8	37,281.9
SUBTOTAL			0.0	0.0	2,924.7	0.0	37,959.9	41,070.8	41,070.8	37,281.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	41,070.8	37,281.9
TOTAL OF 3.9 YRS			0.0	0.0	2,924.7	0.0	37,959.9	41,070.8	41,070.8	37,281.9

PRESENT WORTH PROFILE	
DISC RATE %	CUM PW M$
0.000	41,070.8
5.000	39,057.8
10.000	37,281.9
15.000	35,704.0
20.000	34,293.0
25.000	33,024.0
30.000	31,876.6
35.000	30,834.1
40.000	29,882.8
50.000	28,209.3

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

Table I

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PROBABLE RESERVES

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2017	203.5	0.0	1,364.6	36.6	4.8	240.7	52.44	40.76	6.114	1,921.1	195.0	1,471.6	3,587.6
12-31-2018	510.6	0.0	3,384.0	91.9	11.9	596.9	52.50	40.80	5.921	4,825.5	484.0	3,534.5	8,843.9
12-31-2019	576.2	0.0	3,843.4	103.7	13.5	678.0	52.91	41.11	5.799	5,487.2	553.9	3,931.6	9,972.7
12-31-2020	695.8	0.0	4,702.5	125.2	16.5	829.5	63.81	49.40	6.432	7,991.7	814.3	5,335.2	14,141.2
12-31-2021	803.2	0.0	5,220.4	144.6	18.3	920.9	68.81	53.20	6.432	9,948.5	973.6	5,922.8	16,844.8
12-31-2022	632.1	0.0	4,202.2	113.8	14.7	741.3	73.81	57.00	6.432	8,398.6	839.7	4,767.6	14,005.8
08-31-2023	344.1	0.0	2,287.0	61.9	8.0	403.4	73.81	57.00	7.163	4,571.5	457.0	2,889.8	7,918.3
SUBTOTAL	3,765.5	0.0	25,004.0	677.8	87.7	4,410.7	63.65	49.26	6.315	43,143.9	4,317.4	27,853.0	75,314.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,765.5	0.0	25,004.0	677.8	87.7	4,410.7	63.65	49.26	6.315	43,143.9	4,317.4	27,853.0	75,314.4
CUM PROD	0.0	0.0	0.0										
ULTIMATE	3,765.5	0.0	25,004.0										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	461.4	3,126.2	3,126.2	3,048.9
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	1,330.5	7,513.5	10,639.7	9,874.6
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	2,067.7	7,905.0	18,544.7	16,404.0
12-31-2020	1	0.2	0.0	0.0	0.0	0.0	4,027.1	10,114.1	28,658.9	23,990.5
12-31-2021	2	0.4	0.0	0.0	430.3	0.0	8,899.1	7,515.4	36,174.3	29,145.5
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	10,630.2	2,619.6	38,793.8	30,795.2
08-31-2023	3	0.5	0.0	0.0	516.7	0.0	6,927.8	473.8	39,267.6	31,070.1
SUBTOTAL			0.0	0.0	1,703.0	0.0	34,343.8	39,267.6	39,267.6	31,070.1
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	39,267.6	31,070.1
TOTAL OF 6.2 YRS			0.0	0.0	1,703.0	0.0	34,343.8	39,267.6	39,267.6	31,070.1

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	39,267.6
5.000	34,756.6
10.000	31,070.1
15.000	28,020.5
20.000	25,469.7
25.000	23,314.6
30.000	21,477.0
35.000	19,897.2
40.000	18,528.4
50.000	16,285.3

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table II

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,308.1	0.0	8,755.5	235.5	30.7	1,544.5	52.44	40.76	6.084	12,347.6	1,251.0	9,396.7	22,995.3
12-31-2018	2,151.2	0.0	14,429.7	387.2	50.6	2,545.4	52.48	40.79	5.955	20,321.9	2,063.2	15,158.2	37,543.3
12-31-2019	1,663.9	0.0	11,187.2	299.5	39.2	1,973.4	52.89	41.10	5.813	15,841.6	1,611.9	11,471.0	28,924.5
12-31-2020	1,296.5	0.0	8,730.5	233.4	30.6	1,540.1	63.81	49.40	6.432	14,891.3	1,511.9	9,905.3	26,308.4
12-31-2021	928.9	0.0	6,107.9	167.2	21.4	1,077.4	68.81	53.20	6.432	11,505.5	1,139.1	6,929.8	19,574.4
12-31-2022	632.1	0.0	4,202.2	113.8	14.7	741.3	73.81	57.00	6.432	8,398.6	839.7	4,767.6	14,005.8
08-31-2023	344.1	0.0	2,287.0	61.9	8.0	403.4	73.81	57.00	7.163	4,571.5	457.0	2,889.8	7,918.3
SUBTOTAL	8,324.8	0.0	55,700.1	1,498.5	195.3	9,825.5	58.65	45.45	6.159	87,877.9	8,873.7	60,518.4	157,269.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	8,324.8	0.0	55,700.1	1,498.5	195.3	9,825.5	58.65	45.45	6.159	87,877.9	8,873.7	60,518.4	157,269.9
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	71,380.6	0.0	386,788.9										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	6,405.6	16,079.0	16,079.0	15,706.9
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	12,262.1	24,596.2	40,675.2	38,157.1
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	12,372.7	15,849.7	56,524.9	51,319.7
12-31-2020	5	0.9	0.0	0.0	719.6	0.0	12,581.3	13,007.5	69,532.3	61,132.9
12-31-2021	4	0.7	0.0	0.0	737.6	0.0	11,124.0	7,712.8	77,245.1	66,427.4
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	10,630.2	2,619.6	79,864.7	68,077.1
08-31-2023	3	0.5	0.0	0.0	516.7	0.0	6,927.8	473.8	80,338.5	68,352.0
SUBTOTAL			0.0	0.0	4,627.7	0.0	72,303.7	80,338.5	80,338.5	68,352.0
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	80,338.5	68,352.0
TOTAL OF 6.2 YRS			0.0	0.0	4,627.7	0.0	72,303.7	80,338.5	80,338.5	68,352.0

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	80,338.5
5.000	73,814.4
10.000	68,352.0
15.000	63,724.5
20.000	59,762.7
25.000	56,338.5
30.000	53,353.6
35.000	50,731.3
40.000	48,411.1
50.000	44,494.6

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

Table III

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

POSSIBLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	281.9	0.0	1,851.5	50.7	6.5	326.6	52.44	40.76	6.098	2,660.6	264.5	1,991.6	4,916.7
12-31-2018	578.9	0.0	3,805.3	104.2	13.3	671.3	52.49	40.80	5.935	5,470.2	544.2	3,983.7	9,998.1
12-31-2019	566.2	0.0	3,727.7	101.9	13.1	657.6	52.90	41.11	5.794	5,391.0	537.2	3,809.7	9,737.9
12-31-2020	530.9	0.0	3,504.4	95.6	12.3	618.2	63.81	49.40	6.432	6,098.3	606.9	3,976.0	10,681.1
12-31-2021	566.8	0.0	3,904.0	102.0	13.7	688.7	68.81	53.20	6.432	7,021.1	728.1	4,429.3	12,178.4
12-31-2022	516.7	0.0	3,342.2	93.0	11.7	589.6	73.81	57.00	6.432	6,864.5	667.8	3,791.8	11,324.2
12-31-2023	605.3	0.0	3,949.3	108.9	13.8	696.7	73.81	57.00	7.163	8,041.8	789.1	4,990.3	13,821.3
12-31-2024	742.9	0.0	4,901.0	133.7	17.2	864.5	75.69	58.43	7.364	10,120.4	1,003.8	6,366.8	17,491.0
04-30-2025	191.7	0.0	1,277.8	34.5	4.5	225.4	77.61	59.89	7.571	2,677.3	268.2	1,706.4	4,652.0
SUBTOTAL	4,581.2	0.0	30,263.2	824.6	106.1	5,338.4	65.90	50.99	6.565	54,345.3	5,409.8	35,045.7	94,800.7
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,581.2	0.0	30,263.2	824.6	106.1	5,338.4	65.90	50.99	6.565	54,345.3	5,409.8	35,045.7	94,800.7
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,581.2	0.0	30,263.2										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	ACTIVE COMPLETIONS		PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	572.7	4,344.1	4,344.1	4,240.3
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	1,291.1	8,707.1	13,051.1	12,161.9
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	1,521.6	8,216.3	21,267.4	18,961.9
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,760.4	8,920.8	30,188.1	25,671.2
12-31-2021	1	0.2	0.0	0.0	0.0	0.0	2,626.6	9,551.8	39,740.0	32,208.6
12-31-2022	0	0.0	0.0	0.0	0.0	0.0	2,875.1	8,449.1	48,189.1	37,457.3
12-31-2023	1	0.2	0.0	0.0	258.3	0.0	6,526.2	7,036.7	55,225.8	41,441.2
12-31-2024	4	0.7	0.0	0.0	794.4	0.0	12,976.5	3,720.2	58,946.0	43,377.8
04-30-2025	3	0.5	0.0	0.0	271.4	0.0	4,258.3	122.2	59,068.2	43,436.9
SUBTOTAL			0.0	0.0	1,324.1	0.0	34,408.4	59,068.2	59,068.2	43,436.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	59,068.2	43,436.9
TOTAL OF 7.8 YRS			0.0	0.0	1,324.1	0.0	34,408.4	59,068.2	59,068.2	43,436.9

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	59,068.2
5.000	50,244.9
10.000	43,436.9
15.000	38,088.9
20.000	33,819.0
25.000	30,359.4
30.000	27,518.4
35.000	25,156.9
40.000	23,171.9
50.000	20,042.1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

Table IV

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,589.9	0.0	10,607.1	286.2	37.2	1,871.1	52.44	40.76	6.087	15,008.2	1,515.5	11,388.3	27,912.0
12-31-2018	2,730.2	0.0	18,235.0	491.4	63.9	3,216.7	52.48	40.79	5.951	25,792.1	2,607.4	19,141.9	47,541.4
12-31-2019	2,230.1	0.0	14,914.8	401.4	52.3	2,631.0	52.89	41.10	5.808	21,232.6	2,149.0	15,280.7	38,662.4
12-31-2020	1,827.4	0.0	12,235.0	328.9	42.9	2,158.2	63.81	49.40	6.432	20,989.6	2,118.8	13,881.2	36,989.5
12-31-2021	1,495.8	0.0	10,011.9	269.2	35.1	1,766.1	68.81	53.20	6.432	18,526.6	1,867.1	11,359.0	31,752.8
12-31-2022	1,148.8	0.0	7,544.4	206.8	26.4	1,330.8	73.81	57.00	6.432	15,263.1	1,507.5	8,559.5	25,330.0
12-31-2023	949.4	0.0	6,236.3	170.9	21.9	1,100.1	73.81	57.00	7.163	12,613.3	1,246.1	7,880.2	21,739.5
12-31-2024	742.9	0.0	4,901.0	133.7	17.2	864.5	75.69	58.43	7.364	10,120.4	1,003.8	6,366.8	17,491.0
04-30-2025	191.7	0.0	1,277.8	34.5	4.5	225.4	77.61	59.89	7.571	2,677.3	268.2	1,706.4	4,652.0
SUBTOTAL	12,906.0	0.0	85,963.3	2,323.1	301.3	15,163.9	61.22	47.40	6.302	142,223.1	14,283.5	95,564.0	252,070.6
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	12,906.0	0.0	85,963.3	2,323.1	301.3	15,163.9	61.22	47.40	6.302	142,223.1	14,283.5	95,564.0	252,070.6
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	75,961.8	0.0	417,052.1										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES			PRESENT WORTH PROFILE	
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%		
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM	DISC RATE	CUM PW
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$	%	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	6,978.3	20,423.0	20,423.0	19,947.2	0.000	139,406.7
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	13,553.2	33,303.3	53,726.3	50,319.1	5.000	124,059.3
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	13,894.3	24,066.0	77,792.2	70,281.5	10.000	111,789.0
12-31-2020	5	0.9	0.0	0.0	719.6	0.0	14,341.7	21,928.2	99,720.5	86,804.1	15.000	101,813.4
12-31-2021	5	0.9	0.0	0.0	737.6	0.0	13,750.6	17,264.6	116,985.1	98,636.0	20.000	93,581.7
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	13,505.2	11,068.7	128,053.8	105,534.4	25.000	86,697.9
12-31-2023	4	0.7	0.0	0.0	775.0	0.0	13,454.0	7,510.5	135,564.3	109,793.3	30.000	80,872.0
12-31-2024	4	0.7	0.0	0.0	794.4	0.0	12,976.5	3,720.2	139,284.5	111,729.8	35.000	75,888.1
04-30-2025	3	0.5	0.0	0.0	271.4	0.0	4,258.3	122.2	139,406.7	111,789.0	40.000	71,583.1
											50.000	64,536.7
SUBTOTAL			0.0	0.0	5,951.8	0.0	106,712.1	139,406.7	139,406.7	111,789.0		
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	139,406.7	111,789.0		
TOTAL OF 7.8 YRS			0.0	0.0	5,951.8	0.0	106,712.1	139,406.7	139,406.7	111,789.0		

BASED ON ESCALATED PRICE AND COST PARAMETERS
BASE PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Table V

REVENUE, TAXES, AND COSTS (M$)
SERICA ENERGY PLC
ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

BASE PRICE CASE

Category	Working Interest Gross Revenue	Capital Costs	Abandonment Costs(1)	Operating Costs	Future Net Revenue Before Income Tax Discounted at 0%	Future Net Revenue Before Income Tax Discounted at 10%	United Kingdom Corporate Income Taxes(2)	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 0%	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 10%
Proved Developed Producing	81,955.5	2,924.7	0.0	37,959.9	41,070.8	37,281.9	0.0	41,070.8	37,281.9
Probable	75,314.4	1,703.0	0.0	34,343.8	39,267.6	31,070.1	0.0	39,267.6	31,070.1
Proved + Probable (2P)	157,269.9	4,627.7	0.0	72,303.7	80,338.5	68,352.0	0.0	80,338.5	68,352.0
Possible	94,800.7	1,324.1	0.0	34,408.4	59,068.2	43,436.9	0.0	59,068.2	43,436.9
Proved + Probable + Possible (3P)	252,070.6	5,951.8	0.0	106,712.1	139,406.7	111,789.0	0.0	139,406.7	111,789.0

(1) Serica is not liable for abandonment costs up to a maximum value that exceeds its current estimates of abandonment costs.
(2) Serica is not liable for United Kingdom corporate income taxes up to a maximum value that exceeds its current estimate of loss carry-forward costs.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

TECHNICAL DISCUSSION

TECHNICAL DISCUSSION
RESERVES AND UNRISKED CONTINGENT AND PROSPECTIVE RESOURCES
IRISH WATERS IN THE ATLANTIC OCEAN AND
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

1.0 GENERAL OVERVIEW AND SCOPE OF WORK

Netherland, Sewell & Associates, Inc. has estimated the proved developed producing, probable, and possible reserves and future revenue, as of June 30, 2017, to the Serica Energy plc (Serica) interest in certain gas properties located in Erskine Field, United Kingdom (UK) Sector of the Central North Sea. We have also estimated the unrisked contingent and prospective resources, as of June 30, 2017, to the Serica interest in certain discoveries and prospects located in Irish waters in the Atlantic Ocean and the UK Sector of the Central North Sea. It is our understanding that Serica Energy Slyne B.V. and Serica Energy (UK) Limited own the interests in these properties and are wholly owned subsidiaries of Serica. Gross volumes shown in this Competent Person's Report (report) are 100 percent of the volumes expected to be produced from the properties.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves, contingent resources, and prospective resources in this report have been estimated using a combination of deterministic and probabilistic methods; these estimates have been prepared in accordance with generally accepted petroleum engineering and evaluation principles set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to classify, categorize, and estimate volumes in accordance with the 2007 Petroleum Resources Management System definitions and guidelines. The contingent and prospective resources shown in this report are for undeveloped locations; such volumes are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

2.0 OVERVIEW OF BLOCK AND LICENSE AREAS

The block and license areas described herein cover approximately 442 square kilometers (km^2). Serica currently owns interests in 10 blocks in Irish waters in the Atlantic Ocean and the UK Sector of the Central North Sea. These blocks include one producing field, two discovered and undeveloped fields, and eight prospects. Serica Energy (UK) Limited operates the UK Sector of the Central North Sea and Serica Energy Slyne B.V. operates the Irish waters in the Atlantic Ocean. Location maps of the blocks in which Serica owns an interest are shown in Figures 1 through 3. The table below describes the blocks in which Serica owns an interest. A more comprehensive table showing license, operator, license expiration date, license area, working interest, status, and comments about the properties is included in Figure 4.

Region/License/Area	Operator	Serica Working Interest (%)	License Expiration Date	License Area (km^2)
Irish Waters in the Atlantic Ocean				
FEL 01/06	Serica Energy Slyne B.V.	100	12/2023	305
Achill Prospect, Block 27/9				
Bandon Discovery, Block 27/4				
Bandon South Prospect, Block 27/4				
Boyne Prospect, Blocks 27/4 and 27/5				
Liffey Prospect, Block 27/9				
UK Sector of the Central North Sea				
P 0057	Chevron North Sea Limited	18	-	4
Erskine Field, Block 23/26a				
P 0101	Serica Energy (UK) Limited	50	12/2031	9
Columbus Field, Block 23/21a				
P 0264	Chevron North Sea Limited	18	-	23
Erskine Field, Block 23/26b				
P 1314	Serica Energy (UK) Limited	50	12/2031	22
Columbus Field, Block 23/16f				
P 1620	Eni (UK) Ltd	15	6/2035	75
Rowallan Prospect, Block 22/19c				

3.0 RESERVES

3.1 OVERVIEW

Erskine Field is a developed gas-condensate field that straddles Blocks 23/26a and 23/26b. Erskine Field was discovered following the completion of the 23/26b-4 discovery well in January 1985. The 23/26b-8 appraisal well was drilled adjacent to the discovery well in 1988. Two intervals in the Jurassic were tested, at depths of 4,600 to 4,780 meters (m) true vertical depth subsea (TVDSS).

The five production wells were drilled from a single wellhead platform. The first two wells, the W1 and W2, are located in the southern and eastern areas of the field and were drilled to target the Erskine and Pentland Reservoirs. Both wells initially produced from the Pentland Reservoir. However, in May 2004, the W2 well was plugged in the Pentland Reservoir and recompleted to the overlying Erskine Reservoir. The W1 well continues to produce from the Pentland Reservoir. The third well, the W3, was drilled in the same area of the field, between the W1 and W2 wells, and specifically targets the Erskine Reservoir.

Erskine Field began producing in 1997. The W4 and W5 wells were drilled later the same year. The W4 well was drilled into the Kimmeridge Reservoir, a sandstone in the Heather Formation, and is producing in the Alpha Terrace fault block. It is the only Erskine Field development well that does so. The W5 well was drilled near the northern extent of the field in the Erskine Reservoir.

3.2 GEOLOGY AND GEOPHYSICS

Erskine Field is located in the western portion of the East Central Graben in the Central North Sea and consists of three fault blocks formed during Late Jurassic rifting. These fault blocks are the Main Field Block, the Alpha Terrace, and the Beta Terrace; the latter two are downthrown from the Main Field Block. The Main Field Block is the largest fault block and contains the majority of the well penetrations. No wells are drilled into the Beta Terrace, but it is likely depleted across the fault by the main field wells.

The field contains three reservoirs of interest: Erskine, Kimmeridge, and Pentland. The Pentland Reservoir is Middle Jurassic in age and is the deepest of the three reservoirs. Overlying the Pentland Reservoir is the Erskine Reservoir, which is Late Oxfordian sandstone. The Kimmeridge Reservoir is above the Erskine Reservoir and is Late Oxfordian Heather turbidite.

The Pentland Formation comprises a heterolithic sequence of sandstones, siltstones, mudstones, and coals deposited in a fluvial to lacustrine environment. The sequence is approximately 550 m thick over the field area. The overlying Late Oxfordian Puffin Formation is known locally as the Erskine Sandstone and is between 60 and 90 m thick. This interval consists of a very fine- to fine-grained muddy sandstone deposited in an offshore transition zone setting. The depositional environment for the Pentland, Erskine, and Kimmeridge sands is consistent with the marine transgression associated with the main phase of rifting during the Late Jurassic.

The thickness of the Heather Formation above the Erskine Reservoir is controlled largely by the degree of erosion from the Base Cretaceous Unconformity. The downfaulted Alpha Terrace has a thicker section of Heather Formation than seen in the Main Field Block and the Beta Terrace. Within the Heather Formation in the Alpha Terrace, two thin sand intervals, each approximately 10 m thick, are present. These Kimmeridge Reservoir sands are interpreted to be deepwater turbidite sand deposits and are produced by the W4 well. The distribution of this sandstone away from the W4 well is unknown because of the lack of a definitive seismic response from the beds.

3.3 RESERVES AND METHODOLOGY

Figures 5 and 6 present the operator and the gross and net reserves for the properties described in this section of the report. We estimate the gross and net reserves and future net revenue to the Serica interest in Erskine Field, as of June 30, 2017, to be:

	Gross Reserves		Net Reserves			Future Net Revenue After Income Taxes (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	NGL (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	4,559.3	30,696.1	820.7	107.6	5,414.8	41,070.8	37,281.9
Probable	3,765.5	25,004.0	677.8	87.7	4,410.7	39,267.6	31,070.1
Proved + Probable (2P)	8,324.8	55,700.1	1,498.5	195.3	9,825.5	80,338.5	68,352.0
Possible	4,581.2	30,263.2	824.6	106.1	5,338.4	59,068.2	43,436.9
Proved + Probable + Possible (3P)	12,906.0	85,963.3	2,323.1	301.3	15,163.9	139,406.7	111,789.0

Totals may not add because of rounding.

The oil volumes shown include condensate only. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases. Monetary values shown in this report are expressed in United States dollars ($), thousands of United States dollars (M$), or millions of United States dollars (MM$) using the October 13, 2017, United States Federal Reserve exchange rate of $1.3304 per British pound sterling.

Reserves have been estimated using decline curve analysis only.

3.4 LOMOND PLATFORM COST SHARING

Erskine Field owners' share of the operating costs for the Lomond Platform are based on a cost sharing agreement between the Erskine Field owners and other producers to the platform. Erskine Field owners share operating costs for the Lomond Platform with other users of the platform based on the ratio of production in oil-equivalent barrels from each field flowing to the Lomond Platform. Serica's portion of shared costs shown in this report is based on our estimates of future production rates for Erskine Field and Serica's estimates of future production rates for other users of the platform.

3.5 SENSITIVITIES ANALYSIS

As requested, Low and High Price Case sensitivities were prepared. Oil, NGL, and gas prices for the Low and High Price Cases are 15 percent lower and higher than the Base Price Case, respectively. Average annual prices for the Low and High Price Cases, before adjustments, are shown in the following table:

	Low Price Case			High Price Case		
	Oil/	Gas Price		Oil/	Gas Price	
Period Ending	NGL Price ($/Barrel)	(Pence/ therm)	($/MMBTU)	NGL Price ($/Barrel)	(Pence/ therm)	($/MMBTU)
12-31-2017	45.58	40.5	5.394	61.67	54.9	7.297
12-31-2018	45.63	39.6	5.272	61.73	53.6	7.132
12-31-2019	45.98	38.8	5.159	62.21	52.5	6.980
12-31-2020	55.25	42.5	5.654	74.75	57.5	7.650
12-31-2021	59.50	42.5	5.654	80.50	57.5	7.650
12-31-2022	63.75	42.5	5.654	86.25	57.5	7.650
12-31-2023	63.75	46.8	6.220	86.25	63.3	8.415

Thereafter escalated 2.5 percent on January 1 of each year.

Summary projections of reserves and revenue by reserves category for the Low and High Price Cases are shown in Figures 7 through 16. A table of revenue, taxes, and costs for the Low and High Price Cases is shown in Figure 17.

4.0 CONTINGENT RESOURCES

Contingent resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from known accumulations, but for which the applied project or projects are not yet considered mature enough for commercial development because of one or more contingencies. The contingent resources shown in this report subclassified as development pending are contingent upon finalization and approval of a development plan and commitment from the owners to develop the field. The contingent resources shown in this report subclassified as development not viable are contingent upon acquisition of additional technical data that demonstrate producing rates and volumes sufficient to sustain economic viability, generation and approval of a development plan, and commitment from the owners to develop the discoveries. This report does not include economic analysis for these properties. Based on analogous field developments, it appears that the best estimate development pending contingent resources in this report have a reasonable chance of being economically viable. If these contingencies are successfully addressed, some portion of the contingent resources estimated in this report may be reclassified as reserves; our estimates have not been risked to account for the possibility that the contingencies are not successfully addressed.

Figures 18 and 19 present the operator, risk factors, and gross (100 percent) and working interest unrisked contingent resources for the properties described in this section of the report. We estimate the unrisked contingent resources and the risk factor for these properties, as of June 30, 2017, to be:

	Unrisked Contingent Resources				
	Gross		Working Interest		Risk
Subclass/Region/Area/Category	Oil (MBBL)	Gas (MMCF)	Oil (MBBL)	Gas (MMCF)	Factor[1] (%)
Development Pending					
UK Sector of the Central North Sea					
Columbus Field					
Low Estimate (1C)	1,269.2	28,857.3	634.6	14,428.7	85
Best Estimate (2C)	2,793.7	63,533.2	1,396.9	31,766.6	85
High Estimate (3C)	3,636.2	82,284.1	1,818.1	41,142.1	85
Development Not Viable					
Irish Waters in the Atlantic Ocean					
Bandon Discovery					
Low Estimate (1C)	0.0	0.0	0.0	0.0	0
Best Estimate (2C)	0.0	0.0	0.0	0.0	0
High Estimate (3C)	0.0	0.0	0.0	0.0	0

[1] The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

The contingent resources shown in this report have been estimated using deterministic methods. Once all contingencies have been successfully addressed, the approximate probability that the quantities of contingent resources actually recovered will equal or exceed the estimated amounts is generally inferred to be 90 percent for the low estimate, 50 percent for the best estimate, and 10 percent for the high estimate. For the purposes of this report, the volumes and parameters associated with the low, best, and high estimate scenarios of contingent resources are referred to as 1C, 2C, and 3C, respectively.

4.1 COLUMBUS FIELD

4.1.1 Overview

Columbus Field is an undeveloped gas-condensate field in the Paleocene Forties Sandstone. The field is located in Blocks 23/16f and 23/21 in the Central Graben Basin. Hydrocarbons were first encountered in the area by the 23/16a-2 well drilled by British Petroleum Exploration and Production in 1988. The main accumulation at Columbus Field was discovered by the 23/16f-11 well, which was drilled in November and December 2006, and tested by drillstem test (DST) at a rate of 17 million cubic feet of gas per day (MMCFD) and 1.06 MBBL of condensate per day. The field has been appraised with the 23/16f-12 well to the north and the 23/16f-12z sidetrack to the south of the 23/16f-12 well.

4.1.2 Geology and Geophysics

The Forties Sandstone consists of a series of amalgamated submarine fan channel sandstones deposited in a sand-rich fairway. Columbus Field lies close to the eastern margin of the Forties play fairway. A stratigraphic column for Columbus Field is shown in Figure 20.

The 23/16f-11 discovery well was drilled into an anomalous seismic amplitude in the Forties Sandstone on the western flank of the Paleocene high that was tested by the 23/16a-2 well. The 23/16a-2 well, drilled for a deeper objective, found approximately 2.5 m of possible hydrocarbon-bearing sand in the Forties Sandstone. A DST was performed on that section along with the Andrew section, but the outcome of the test is uncertain. The discovery well was drilled approximately 3.5 kilometers (km) to the southwest of the 23/16a-2 well and encountered an 80-m-thick section of Forties Sandstone with gas to the base, establishing a lowest known gas level. Log analysis shows gas is present in the formation down to a depth of 3,005 m or 9,859 feet (ft) TVDSS.

A second well, the 23/16f-12, was drilled in May 2007 into a separate anomalous amplitude approximately 3.3 km north of the 23/16f-11 well and found an 18.5-m gas column. Log analysis indicates an apparent gas-water contact (GWC) at 2,964 m (9,724 ft) TVDSS, although it is uncertain whether the wet sands below the contact are in vertical pressure communication with the gas-bearing formation. If so, this depth would be characterized as gas down to (GDT) rather than a GWC. The 23/16f-12 well was sidetracked approximately 1,450 m (4,757 ft) to the south into the same anomalous amplitude where the discovery well was drilled; the sidetrack is approximately 2.1 km northwest of the discovery well. The sidetrack well, the 23/16f-12z, found a slightly different apparent GDT at 3,010 m (9,875 ft) TVDSS, 5 m lower than the discovery well.

For the geologic evaluation, we reviewed and utilized a Petrel project originally built by Serica and containing its interpretations. In addition, Serica provided a Columbus Field Reservoir Model Report explaining the geologic model and the outcomes of that modeling and various ancillary reports that include, but are not limited to, petrophysical evaluation, petrophysical cutoffs modeling, seismic depth modeling, frequency modeling, and amplitude-versus-offset modeling. We did not perform an independent review of the seismic data.

Wells drilled by BG Group plc from Block 23/21, which is located to the south of Block 23/16f, that are in the same anomalous amplitude trend were also reviewed, interpreted, and used in the Petrel model by Serica. Similar to the 23/16f-12z well, the three closest of the BG Group plc wells, the 23/21-7, 23/21-7z, and 23/21-7x, also showed different reservoir pressures and different GDTs by log analysis. There are two interpretations that could explain the difference in apparent GDTs by log analysis. In one interpretation, the apparent GDTs could be explained by the presence of a basal seal at the F-4.2 level. Below this seal the sands are not in pressure communication with the sands above them, and the different apparent GDTs above the seal are due to changes in water saturation above a single free water level that was observed in the 23/16f-12z well. The second interpretation of the apparent GDTs is that they are actually GWCs, which would suggest the reservoir is compartmentalized by faulting or shale-outs between sand accumulations.

Initial reservoir pressure is approximately 4,687 psia at a datum depth of 10,000 ft TVDSS. Reservoir temperature is approximately 263°F. Modular dynamics test (MDT) pressure measurements also indicate that there could be different GWCs in many of the wells. However, the interpretation of the pressure data is complicated by indications that some of the wells in Block 23/21 are in communication with Lomond Field, located approximately 4 km to the southeast of Columbus Field and shown on the location map in Figure 1, and that the observed pressure and contact differences may actually be pressure differential reduction from production in Lomond Field. This conclusion is supported by the progressive apparent drawdown correlating with wellbore proximity to Lomond Field, as shown on the graph of MDT data in Figure 21.

Based on the observable data discussed above, we know that there are apparent differences in GDTs by log analysis. Therefore, in the 1C case Columbus Field has been divided into different segments with different GWCs.

Columbus Field was discovered by drilling into an anomalous amplitude in the Forties Sandstone that was defined by seismic data. Because several other fields in this part of the North Sea have been similarly discovered, amplitude data are very important in defining where these gas-charged Forties Sandstone channels are. Although the amplitude does diminish, the structure of Columbus Field does not close in the northern part of the field where it is affected by the Mondo salt diapir to the west. Therefore, a stratigraphic component of closure is needed for the Columbus trap, the presence of which is required for a hydrocarbon reservoir, to work. Because of this, in the 1C case we limited the area of gas to the anomalous amplitude areas that are shown as polygons in Figure 22.

Our 2C case employs the F-4.2 basal seal assumptions to combine the core area containing the 23/16f-12z, 23/16f-11, and 23/21-7x wells into a single, noncompartmentalized region. Our 3C case also includes volumes from the F-3 zone.

4.1.3 Development Plan

Serica's current development plan includes a single horizontal development well. The well's lateral will run along the axis of the field in the central and southeastern portions of the field. There are two production export options currently under consideration. One option is to drill a subsea well and tie back to the Shearwater Platform through infrastructure shared with the planned Arran development. Alternatively, an extended reach well might be drilled from the Lomond Platform. In either case, finalizing the development plan will entail reaching a production-handling agreement with the owners of one of these platforms.

4.2 BANDON DISCOVERY

The Bandon Discovery is located in Frontier Exploration License (FEL) 01/06 in Irish waters in the Atlantic Ocean. The discovery was made in the Suisnish Sandstone. Core samples taken over the reservoir interval contained heavy oil with an API gravity of approximately 15. The in-situ oil viscosity was measured to be between 114 and 150 centipoise (cp) in the 27/4-1 well and between 275 and 500 cp in the 27/4-1z well. There are no associated contingent resources because of the unfavorable fluid properties. The project maturity subclass for this discovery is development not viable. The viscosity characteristics mean that recovery factors for the discovery would be too low for commercial development. However, we did perform an analysis of original oil-in-place (OOIP) for the discovery. We estimate the OOIP volumes for the Bandon Discovery, as of June 30, 2017, to be:

Discovered OOIP (MMBBL)		
Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
12.7	16.4	21.1

The oil volumes shown include crude oil only.

5.0 PROSPECTIVE RESOURCES

Prospective resources are those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The prospective resources included in this report should not be construed as reserves or contingent resources; they represent exploration opportunities and quantify the development potential in the event a petroleum discovery is made. A geologic risk assessment was performed for each of these prospects, as discussed in subsequent paragraphs. This report does not include economic analysis for these prospects. Based on analogous field developments, it appears that, assuming a discovery is made, the unrisked best estimate prospective resources in this report have a reasonable chance of being economically viable.

Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

Figures 23 and 24 present the operator, risk factors, and gross and working interest unrisked prospective resources for the properties described in this section of the report. We estimate the gross and working interest unrisked prospective resources to the Serica interest in these properties, along with the risk factor, as of June 30, 2017, to be:

	Unrisked Prospective Resources(1)				
	Gross		Working Interest		Risk
Region/Prospect/Category	Oil (MMBBL)	Gas (BCF)	Oil (MMBBL)	Gas (BCF)	Factor(2) (%)
Irish Waters in the Atlantic Ocean					
Achill					
Low Estimate	0.0	120.7	0.0	120.7	26
Best Estimate	0.0	252.7	0.0	252.7	26
High Estimate	0.0	516.5	0.0	516.5	26
Bandon South					
Low Estimate	0.0	6.7	0.0	6.7	26
Best Estimate	0.0	26.9	0.0	26.9	26
High Estimate	0.0	101.7	0.0	101.7	26
Boyne Sherwood					
Low Estimate	0.0	60.8	0.0	60.8	26
Best Estimate	0.0	180.2	0.0	180.2	26
High Estimate	0.0	528.5	0.0	528.5	26
Boyne Suisnish					
Low Estimate	5.6	1.4	5.6	1.4	20
Best Estimate	20.1	5.5	20.1	5.5	20
High Estimate	76.7	22.1	76.7	22.1	20
Liffey Sherwood					
Low Estimate	0.0	52.6	0.0	52.6	26
Best Estimate	0.0	180.4	0.0	180.4	26
High Estimate	0.0	626.7	0.0	626.7	26
Liffey Suisnish					
Low Estimate	30.3	7.6	30.3	7.6	20
Best Estimate	128.2	34.0	128.2	34.0	20
High Estimate	526.7	147.4	526.7	147.4	20
UK Sector of the Central North Sea					
Rowallan Pentland					
Low Estimate	3.5	54.4	0.5	8.2	22
Best Estimate	8.8	118.7	1.3	17.8	22
High Estimate	20.0	259.9	3.0	39.0	22
Rowallan Triassic					
Low Estimate	10.0	134.1	1.5	20.1	22
Best Estimate	33.0	422.4	4.9	63.4	22
High Estimate	113.4	1,463.9	17.0	219.6	22
Total					
Low Estimate	49.4	438.3	37.9	278.1	-
Best Estimate	190.0	1,220.9	154.6	760.8	-
High Estimate	736.9	3,666.7	623.4	2,201.5	-

Notes: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding.

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of discovery".

The oil volumes shown include crude oil and condensate. Oil volumes are expressed in millions of barrels (MMBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in billions of cubic feet (BCF) at standard temperature and pressure bases.

5.1 BLOCK 22/19C

5.1.1 Overview

License P 1620, shown on the location map on Figure 3, is located in the Central Graben Basin of Central North Sea. The basin is composed of a series of horsts and grabens that trend northwest, with the Forties-Montrose High horst block running down the center of the graben. Traps form along the upthrown sides of the faults.

The Triassic Skagerrak Sandstone is the primary target in the license and has been discovered in nearby Fiddich and Marnock Fields located to the southwest and south, respectively. The Middle Jurassic age Pentland Sandstone is a secondary target. The Kimmeridge Clay is the source rock for the fields in the Central Graben Basin. Top and lateral seals are provided by Kimmeridge Clay and Heather shales.

5.1.2 Rowallan Pentland Prospect

The Rowallan Pentland Prospect is an east-dipping, three-way closure terminating against a north-to-south-trending fault to the west and an east-to-west-trending fault to the north. The target reservoir is the Middle Jurassic age Pentland Sandstone. The Kimmeridge Clay provides top and lateral seals. Trap integrity is the primary risk, and the chance of discovery (P_g) risk factor for the prospect is 22 percent.

5.1.3 Rowallan Triassic Prospect

The Rowallan Triassic Prospect is an east-dipping, three-way closure terminating against a north-to-south-trending fault to the west and an east-to-west-trending fault to the north. The target reservoir is the Triassic age Skagerrak Sandstone. The Kimmeridge Clay provides top and lateral seals. Trap integrity is the primary risk, and the P_g risk factor for the prospect is 22 percent.

5.2 FEL 01/06

5.2.1 Overview

The Slyne Basin is an elongate Mesozoic graben oriented in a north-northeast to south-southwest direction. The basin is subdivided into three asymmetric half-grabens by a series of complex transfer fault systems. The Northern Slyne Basin contains Corrib Gas Field; the Central Slyne Basin contains FEL 01/06, which is shown on the location map in Figure 2, with the 27/4-1 discovery well; and the Southern Slyne Basin is undrilled. The basin contains sediments ranging in age from Carboniferous to Tertiary.

Primary reservoirs in the Slyne Basin are the Triassic age Sherwood Sandstone and the Jurassic age Suisnish Sandstone. Both of these reservoirs were seen on the well log of the Bandon 27/4-1 discovery well. Prospective structures are half-grabens, tilted fault blocks, and hanging-wall anticlines. Regional seals are provided by the Triassic age Mercia Halite and Mudstone for the Sherwood Reservoir and by Lower Jurassic age shales for the Suisnish Reservoir. Source rocks are present in Carboniferous coals and Carboniferous and Jurassic shales. The boundaries of the prospects discussed below are also shown on the location map in Figure 2.

5.2.2 Achill Prospect

The Achill Prospect is located in the southern portion of FEL 01/06. This prospect is a west-dipping, high-side, three-way fault closure that targets the Triassic Sherwood Sandstone. The presence of the reservoir and reservoir qualities are proven in the 27/4-1 and 27/5-1 wells, but the Sherwood Sandstone is deeper in this area. The Mercia Mudstone provides the top seal, and juxtaposition against the Lower Jurassic Broadford beds provides the lateral seal across the fault. The Broadford beds are mixed carbonates and clastics and are often tight, but there is a moderate risk of lack of seal. The Jurassic Scalpa Sandstone is a secondary target for this prospect but is a downthrown trap and was not evaluated. The primary risk for this prospect is seal, and the P_g risk factor is 26 percent.

5.2.3 Bandon South Prospect

The Bandon South Prospect is located in the west-central portion of FEL 01/06. This prospect is a high-side fault closure that targets the Triassic Sherwood Sandstone. There is independent four-way closure at the top of the prospect. The Mercia Mudstone provides the top seal, and the lateral fault seal is provided by juxtaposition against the Carboniferous or Permian Zechstein Evaporite. The primary risk for this prospect is seal, and the P_g risk factor is 26 percent.

5.2.4 Boyne Sherwood Prospect

The Boyne Sherwood Prospect is located in the north-central portion of FEL 01/06. This prospect targets the Triassic Sherwood Sandstone. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure at both target levels. The structure is truncated on the eastern side by a down-to-the-west fault. The vertical seal for the Sherwood Sandstone is the Mercia Mudstone, and the lateral seal is Middle Jurassic limestones, which present a seal risk. The P_g risk factor for this prospect is 26 percent.

5.2.4.1 Alternative Volumes

Based on the data we have reviewed, we consider there to be an equal likelihood of the Sherwood Sandstone in the Boyne Sherwood Prospect being oil-charged or being gas-charged. Our estimates of prospective resources in Figures 23 and 24 are based on the reservoir being gas-charged. We have estimated an alternate set of original hydrocarbons-in-place and unrisked prospective resources with the assumption that the hydrocarbon phase discovered will be oil. Since this is an alternative case to the gas reservoir presented, the undiscovered OOIP, undiscovered original gas-in-place, and prospective resources volumes estimated in this report for the Boyne Sherwood Prospect should not be considered additive and should not in any way be combined. This does not preclude the possibility of both hydrocarbon phases being present. The P_g risk factor for this alternative case is 20 percent. The oil formation volume factor for this alternative case is 1.18, 1.26, and 1.36 reservoir barrels per stock tank barrel for the low, best, and high estimates, respectively. Recovery factors for the low, best, and high estimates are 0.25, 0.35, and 0.45, respectively, and the gas-oil ratios for the low, best, and high estimates are 291, 420, and 616 standard cubic feet per barrel, respectively.

Using this alternative assumption, we estimate the undiscovered OOIP volumes and the gross and working interest unrisked prospective resources for the Sherwood Sandstone in the Boyne Sherwood Prospect, as of June 30, 2017, to be:

		Unrisked Prospective Resources			
	Undiscovered	Gross		Working Interest	
	OOIP	Oil	Gas	Oil	Gas
Category	(MMBBL)	(MMBBL)	(BCF)	(MMBBL)	(BCF)
Low Estimate	66.1	22.7	8.9	11.3	4.5
Best Estimate	186.7	64.9	28.1	32.5	14.1
High Estimate	535.6	190.2	86.2	95.1	43.1

The oil volumes shown include crude oil only.

5.2.5 Boyne Suisnish Prospect

The Boyne Suisnish Prospect is located in the north-central portion of FEL 01/06. This prospect targets the Jurassic Suisnish Sandstone. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure at both target levels. The structure is truncated on the eastern side by a down-to-the-west fault. Vertical seals for the Suisnish Sandstone are Lower and Middle Jurassic shales, and the lateral seal is Middle Jurassic limestones, which present a seal risk. The P_g risk factor for this prospect is 20 percent.

5.2.6 Liffey Sherwood Prospect

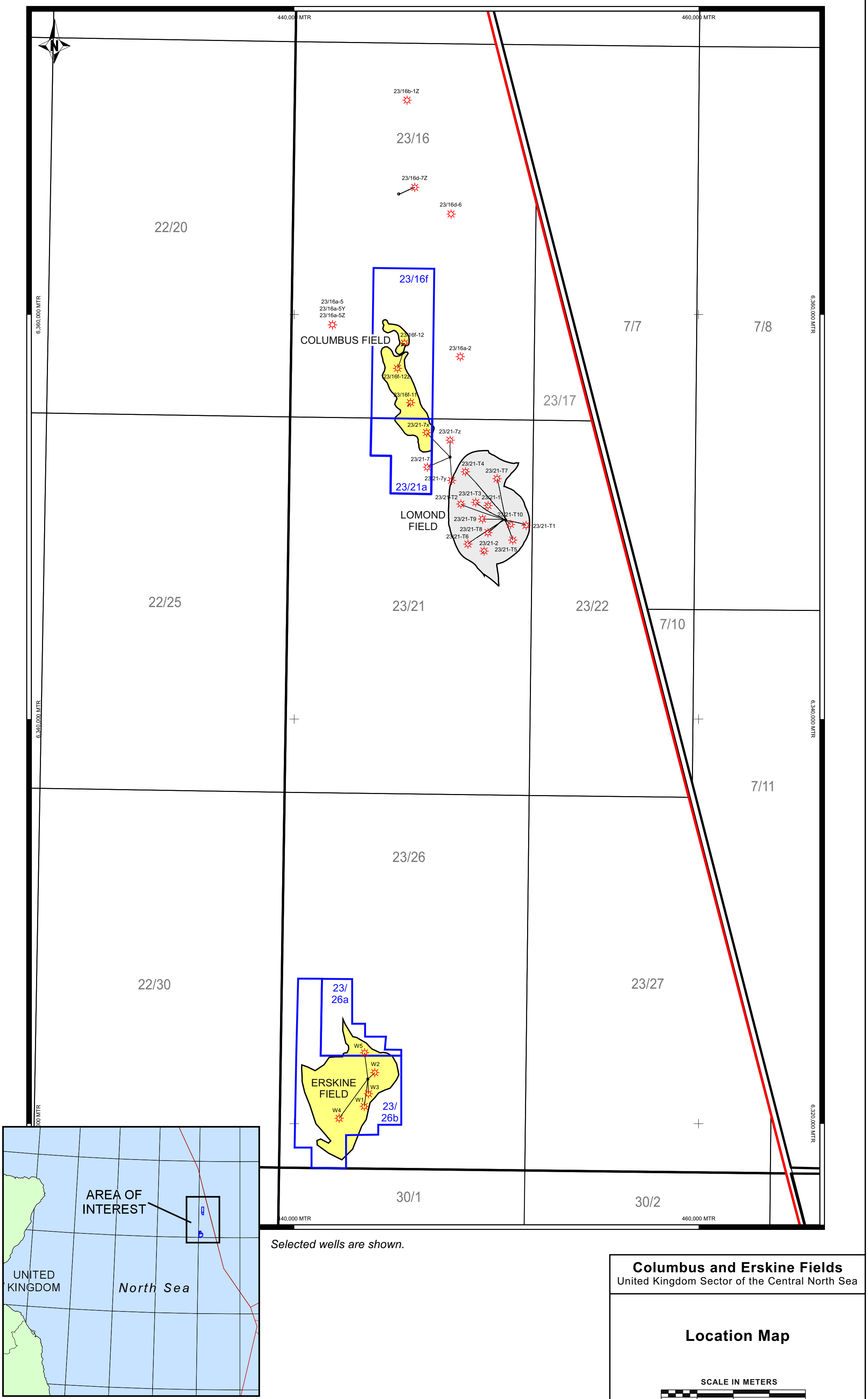
The Liffey Sherwood Prospect is located in the southeastern portion of FEL 01/06. The Triassic Sherwood Sandstone is the reservoir target for this prospect. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure. The vertical seal for the Sherwood Sandstone is the Mercia Mudstone, and the lateral seal is Middle Jurassic limestones. Sealing is the primary risk, and the P_g risk factor for this prospect is 26 percent.

5.2.7 Liffey Suisnish Prospect

The Liffey Suisnish Prospect is located in the southeastern portion of FEL 01/06. The Jurassic Suisnish Sandstone is the reservoir target for this prospect. The structure is a west-dipping, northeast-to-southwest-trending, high-side, three-way closure. Vertical seals for the Suisnish Sandstone are Lower and Middle Jurassic shales, and the lateral seal is Middle Jurassic limestones. Sealing is the primary risk for this prospect, and the P_g risk factor for this prospect is 20 percent.

FIGURES

NETHERLAND, SEWELL & ASSOCIATES, INC.



Selected wells are shown.

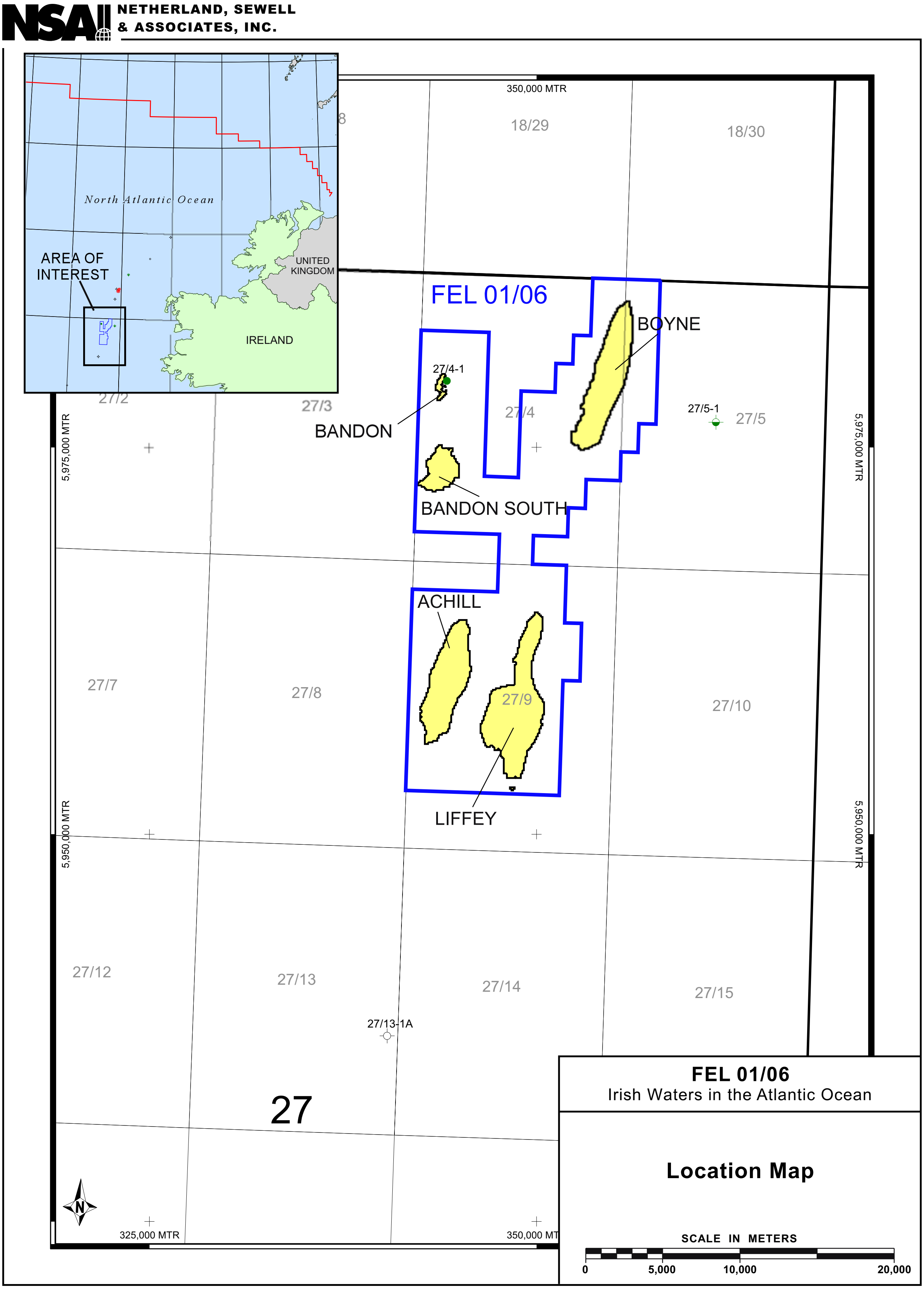
Columbus and Erskine Fields
United Kingdom Sector of the Central North Sea

Location Map

SCALE IN METERS
0 1,800 3,600 7,200

Figure 1

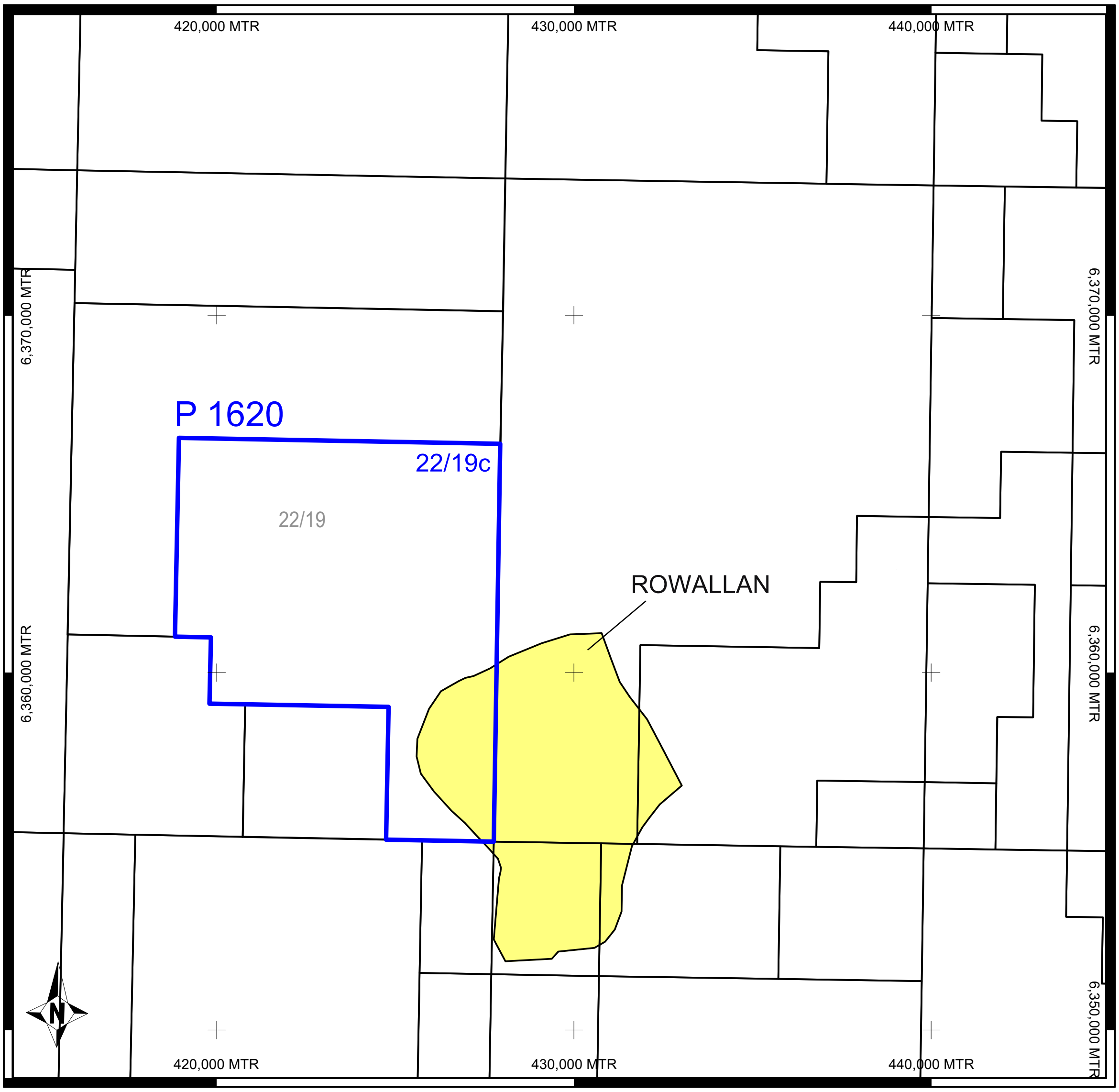
All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

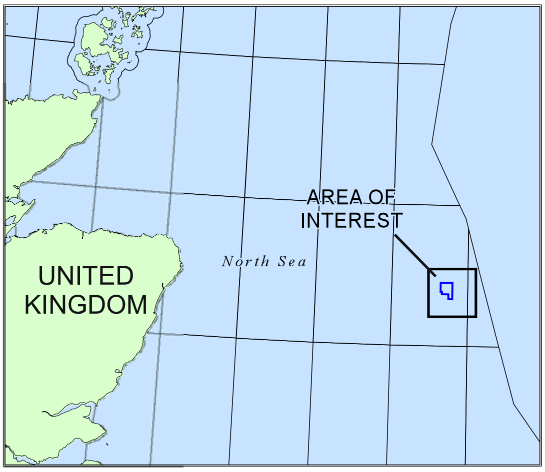


All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 2

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.





License P 1620

United Kingdom Sector of the Central North Sea

Location Map

SCALE IN METERS

0 2,500 5,000 10,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 3

SUMMARY OF ASSETS
SERICA ENERGY PLC INTEREST
LOCATED IN IRISH WATERS IN THE ATLANTIC OCEAN AND
IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

Area/License/Discovery, Field, or Prospect/Block	Operator Name	Serica Working Interest (%)	Status	License Expiration Date	License Area (km^2)	Comments
Irish Waters in the Atlantic Ocean						
FEL 01/06	Serica Energy Slyne B.V.	100		12/2023	305	
Achill Prospect, Block 27/9			Exploration			Exploration license active since 2006
Bandon Discovery, Block 27/4			Development			No feasible development because of unfavorable fluid properties
Bandon South Prospect, Block 27/4			Exploration			Exploration license active since 2006
Boyne Prospect, Blocks 27/4 and 27/5			Exploration			Exploration license active since 2006
Liffey Prospect, Block 27/9			Exploration			Exploration license active since 2006
United Kingdom Sector of the Central North Sea						
P 0057	Chevron North Sea Limited	18		-	4	
Erskine Field, Block 23/26a			Production			Averaged approximately 50 MMCFD in 2017 through 6/30, on decline
P 0101	Serica Energy (UK) Limited	50		12/2031	9	
Columbus Field, Block 23/21a			Development			Current development plan targets first production in 2020
P 0264	Chevron North Sea Limited	18		-	23	
Erskine Field, Block 23/26b			Production			Averaged approximately 50 MMCFD in 2017 through 6/30, on decline
P 1314	Serica Energy (UK) Limited	50		12/2031	22	
Columbus Field, Block 23/16f			Development			Current development plan targets first production in 2020
P 1620	Eni (UK) Ltd	15		06/2035	75	
Rowallan Prospect, Block 22/19c			Exploration			Exploration well scheduled for 2018

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 4

SUMMARY OF OIL AND LIQUIDS RESERVES
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

		Oil and Liquids Reserves (MBBL)					
		Gross (100%)			Net		
Area/Field	Operator Name	Proved (1P)	Proved + Probable (2P)	Proved + Probable + Possible (3P)	Proved (1P)	Proved + Probable (2P)	Proved + Probable + Possible (3P)
United Kingdom Sector of the Central North Sea							
Erskine Field	Chevron North Sea Limited	4,559.3	8,324.8	12,906.0	928.3	1,693.8	2,624.4
Total		4,559.3	8,324.8	12,906.0	928.3	1,693.8	2,624.4

Note: Reserves shown are based on Base Price Case oil prices.

Source: Netherland, Sewell & Associates, Inc.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 5

SUMMARY OF GAS RESERVES
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

		Gas Reserves (MMCF)					
		Gross (100%)			Net		
Area/Field	Operator Name	Proved (1P)	Proved + Probable (2P)	Proved + Probable + Possible (3P)	Proved (1P)	Proved + Probable (2P)	Proved + Probable + Possible (3P)
United Kingdom Sector of the Central North Sea							
Erskine Field	Chevron North Sea Limited	30,696.1	55,700.1	85,963.3	5,414.8	9,825.5	15,163.9
Total		30,696.1	55,700.1	85,963.3	5,414.8	9,825.5	15,163.9

Note: Reserves shown are based on Base Price Case gas prices.

Source: Netherland, Sewell & Associates, Inc.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 6

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED DEVELOPED PRODUCING RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,104.5	0.0	7,391.0	198.8	25.9	1,303.8	44.40	34.64	5.034	8,826.6	897.6	6,562.7	16,286.9
12-31-2018	1,640.6	0.0	11,045.6	295.3	38.7	1,948.5	44.43	34.67	4.938	13,119.4	1,342.3	9,621.1	24,082.9
12-31-2019	1,087.7	0.0	7,343.8	195.8	25.7	1,295.4	44.78	34.93	4.814	8,766.7	899.3	6,236.4	15,902.4
06-30-2020	367.7	0.0	2,439.6	66.2	8.6	430.4	54.06	41.99	5.334	3,577.8	359.1	2,295.5	6,232.3
SUBTOTAL	4,200.5	0.0	28,220.1	756.1	98.9	4,978.0	45.35	35.36	4.965	34,290.4	3,498.3	24,715.7	62,504.5
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,200.5	0.0	28,220.1	756.1	98.9	4,978.0	45.35	35.36	4.965	34,290.4	3,498.3	24,715.7	62,504.5
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	67,256.4	0.0	359,308.9										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE BEFORE INCOME TAXES: UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	5,944.2	9,832.0	9,832.0	9,608.7
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	10,931.7	12,466.2	22,298.2	21,020.0
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	10,305.0	4,895.3	27,193.5	25,120.8
06-30-2020	4	0.7	0.0	0.0	359.8	0.0	4,440.1	1,432.4	28,626.0	26,227.2
SUBTOTAL			0.0	0.0	2,257.6	0.0	31,621.0	28,626.0	28,626.0	26,227.2
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	28,626.0	26,227.2
TOTAL OF 3.0 YRS			0.0	0.0	2,257.6	0.0	31,621.0	28,626.0	28,626.0	26,227.2

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	28,626.0
5.000	27,355.9
10.000	26,227.2
15.000	25,217.4
20.000	24,308.8
25.000	23,486.8
30.000	22,739.5
35.000	22,057.1
40.000	21,431.4
50.000	20,323.6

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 7

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

PROBABLE RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	203.5	0.0	1,364.6	36.6	4.8	240.7	44.39	34.64	5.063	1,626.3	165.7	1,218.8	3,010.8
12-31-2018	510.6	0.0	3,384.0	91.9	11.9	596.9	44.45	34.68	4.900	4,085.3	411.4	2,924.9	7,421.6
12-31-2019	576.2	0.0	3,843.4	103.7	13.5	678.0	44.79	34.95	4.796	4,645.8	470.8	3,251.8	8,368.5
12-31-2020	928.8	0.0	6,290.9	167.2	22.1	1,109.7	54.06	41.99	5.334	9,038.2	926.0	5,919.1	15,883.3
12-31-2021	928.9	0.0	6,107.9	167.2	21.4	1,077.4	58.31	45.22	5.334	9,749.9	968.2	5,746.9	16,465.1
06-30-2022	341.9	0.0	2,269.3	61.5	8.0	400.3	62.56	48.45	5.334	3,850.4	385.4	2,135.2	6,371.0
SUBTOTAL	3,490.0	0.0	23,260.1	628.2	81.5	4,103.1	52.53	40.81	5.166	32,996.0	3,327.6	21,196.8	57,520.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	3,490.0	0.0	23,260.1	628.2	81.5	4,103.1	52.53	40.81	5.166	32,996.0	3,327.6	21,196.8	57,520.4
CUM PROD	0.0	0.0	0.0										
ULTIMATE	3,490.0	0.0	23,260.1										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	461.4	2,549.4	2,549.4	2,486.3
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	1,330.5	6,091.2	8,640.6	8,019.8
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	2,067.7	6,300.8	14,941.4	13,224.5
12-31-2020	1	0.2	0.0	0.0	359.8	0.0	8,141.2	7,382.3	22,323.7	18,774.0
12-31-2021	4	0.7	0.0	0.0	737.6	0.0	11,124.0	4,603.5	26,927.2	21,939.9
06-30-2022	4	0.7	0.0	0.0	378.0	0.0	5,357.3	635.7	27,562.9	22,348.7
SUBTOTAL			0.0	0.0	1,475.5	0.0	28,482.0	27,562.9	27,562.9	22,348.7
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	27,562.9	22,348.7
TOTAL OF 5.0 YRS			0.0	0.0	1,475.5	0.0	28,482.0	27,562.9	27,562.9	22,348.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	27,562.9
5.000	24,714.0
10.000	22,348.7
15.000	20,363.5
20.000	18,680.9
25.000	17,241.9
30.000	16,001.2
35.000	14,923.5
40.000	13,980.9
50.000	12,416.5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 8

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2017	1,308.1	0.0	8,755.5	235.5	30.7	1,544.5	44.39	34.64	5.038	10,452.9	1,063.3	7,781.5	19,297.7
12-31-2018	2,151.2	0.0	14,429.7	387.2	50.6	2,545.4	44.43	34.67	4.929	17,204.7	1,753.7	12,546.0	31,504.5
12-31-2019	1,663.9	0.0	11,187.2	299.5	39.2	1,973.4	44.78	34.94	4.808	13,412.5	1,370.1	9,488.3	24,270.9
12-31-2020	1,296.5	0.0	8,730.5	233.4	30.6	1,540.1	54.06	41.99	5.334	12,616.0	1,285.1	8,214.6	22,115.7
12-31-2021	928.9	0.0	6,107.9	167.2	21.4	1,077.4	58.31	45.22	5.334	9,749.9	968.2	5,746.9	16,465.1
06-30-2022	341.9	0.0	2,269.3	61.5	8.0	400.3	62.56	48.45	5.334	3,850.4	385.4	2,135.2	6,371.0
SUBTOTAL	7,690.5	0.0	51,480.2	1,384.3	180.5	9,081.1	48.61	37.82	5.056	67,286.4	6,825.9	45,912.5	120,024.8
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	7,690.5	0.0	51,480.2	1,384.3	180.5	9,081.1	48.61	37.82	5.056	67,286.4	6,825.9	45,912.5	120,024.8
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	70,746.3	0.0	382,569.0										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	6,405.6	12,381.4	12,381.4	12,095.0
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	12,262.1	18,557.4	30,938.8	29,039.8
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	12,372.7	11,196.1	42,134.9	38,345.3
12-31-2020	5	0.9	0.0	0.0	719.6	0.0	12,581.3	8,814.7	50,949.6	45,001.1
12-31-2021	4	0.7	0.0	0.0	737.6	0.0	11,124.0	4,603.5	55,553.1	48,167.1
06-30-2022	4	0.7	0.0	0.0	378.0	0.0	5,357.3	635.7	56,188.8	48,575.9
SUBTOTAL			0.0	0.0	3,733.0	0.0	60,103.0	56,188.8	56,188.8	48,575.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	56,188.8	48,575.9
TOTAL OF 5.0 YRS			0.0	0.0	3,733.0	0.0	60,103.0	56,188.8	56,188.8	48,575.9

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	56,188.8
5.000	52,069.9
10.000	48,575.9
15.000	45,580.9
20.000	42,989.7
25.000	40,728.7
30.000	38,740.8
35.000	36,980.6
40.000	35,412.3
50.000	32,740.1

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 9

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

POSSIBLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	281.9	0.0	1,851.5	50.7	6.5	326.6	44.39	34.64	5.050	2,252.4	224.8	1,649.3	4,126.5
12-31-2018	578.9	0.0	3,805.3	104.2	13.3	671.3	44.44	34.68	4.912	4,631.1	462.6	3,296.9	8,390.6
12-31-2019	566.2	0.0	3,727.7	101.9	13.1	657.6	44.79	34.94	4.792	4,564.4	456.6	3,150.9	8,171.9
12-31-2020	530.9	0.0	3,504.4	95.6	12.3	618.2	54.06	41.99	5.334	5,166.5	515.8	3,297.3	8,979.7
12-31-2021	566.8	0.0	3,904.0	102.0	13.7	688.7	58.31	45.22	5.334	5,949.7	618.9	3,673.2	10,241.9
12-31-2022	806.9	0.0	5,275.0	145.2	18.5	930.5	62.56	48.45	5.334	9,086.4	895.9	4,963.3	14,945.6
12-31-2023	949.4	0.0	6,236.3	170.9	21.9	1,100.1	62.56	48.45	5.957	10,690.8	1,059.2	6,552.7	18,302.7
08-31-2024	540.5	0.0	3,550.8	97.3	12.4	626.4	64.16	49.66	6.128	6,241.5	618.2	3,838.1	10,697.7
SUBTOTAL	4,821.5	0.0	31,855.1	867.9	111.7	5,619.2	55.98	43.45	5.414	48,582.8	4,852.0	30,421.8	83,856.6
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,821.5	0.0	31,855.1	867.9	111.7	5,619.2	55.98	43.45	5.414	48,582.8	4,852.0	30,421.8	83,856.6
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,821.5	0.0	31,855.1										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES: TAXES					FUTURE NET REVENUE BEFORE INCOME TAXES: UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	CAPITAL COST	ABDNMNT COST	OPERATING EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	572.7	3,553.9	3,553.9	3,468.9
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	1,291.1	7,099.6	10,653.4	9,928.2
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	1,521.6	6,650.3	17,303.7	15,432.4
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,760.4	7,219.3	24,523.0	20,862.2
12-31-2021	1	0.2	0.0	0.0	0.0	0.0	2,626.6	7,615.3	32,138.3	26,074.5
12-31-2022	0	0.0	0.0	0.0	378.0	0.0	8,147.9	6,419.6	38,557.9	30,067.3
12-31-2023	4	0.7	0.0	0.0	775.0	0.0	13,454.0	4,073.7	42,631.6	32,382.6
08-31-2024	4	0.7	0.0	0.0	529.6	0.0	8,780.2	1,387.9	44,019.5	33,109.9
SUBTOTAL			0.0	0.0	1,682.6	0.0	38,154.5	44,019.5	44,019.5	33,109.9
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	44,019.5	33,109.9
TOTAL OF 7.2 YRS			0.0	0.0	1,682.6	0.0	38,154.5	44,019.5	44,019.5	33,109.9

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	44,019.5
5.000	37,901.1
10.000	33,109.9
15.000	29,295.3
20.000	26,212.5
25.000	23,687.1
30.000	21,592.5
35.000	19,835.8
40.000	18,347.2
50.000	15,975.5

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

Figure 10

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,589.9	0.0	10,607.1	286.2	37.2	1,871.1	44.39	34.64	5.040	12,705.3	1,288.1	9,430.8	23,424.2
12-31-2018	2,730.2	0.0	18,235.0	491.4	63.9	3,216.7	44.43	34.67	4.925	21,835.9	2,216.3	15,842.9	39,895.1
12-31-2019	2,230.1	0.0	14,914.8	401.4	52.3	2,631.0	44.78	34.94	4.804	17,976.9	1,826.7	12,639.2	32,442.8
12-31-2020	1,827.4	0.0	12,235.0	328.9	42.9	2,158.2	54.06	41.99	5.334	17,782.5	1,800.9	11,511.9	31,095.3
12-31-2021	1,495.8	0.0	10,011.9	269.2	35.1	1,766.1	58.31	45.22	5.334	15,699.7	1,587.1	9,420.2	26,706.9
12-31-2022	1,148.8	0.0	7,544.4	206.8	26.4	1,330.8	62.56	48.45	5.334	12,936.8	1,281.3	7,098.5	21,316.6
12-31-2023	949.4	0.0	6,236.3	170.9	21.9	1,100.1	62.56	48.45	5.957	10,690.8	1,059.2	6,552.7	18,302.7
08-31-2024	540.5	0.0	3,550.8	97.3	12.4	626.4	64.16	49.66	6.128	6,241.5	618.2	3,838.1	10,697.7
SUBTOTAL	12,512.0	0.0	83,335.3	2,252.2	292.1	14,700.3	51.45	39.97	5.193	115,869.2	11,677.9	76,334.3	203,881.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	12,512.0	0.0	83,335.3	2,252.2	292.1	14,700.3	51.45	39.97	5.193	115,869.2	11,677.9	76,334.3	203,881.4
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	75,567.8	0.0	414,424.1										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	6,978.3	15,935.3	15,935.3	15,563.9
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	13,553.2	25,657.0	41,592.2	38,968.0
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	13,894.3	17,846.4	59,438.6	53,777.7
12-31-2020	5	0.9	0.0	0.0	719.6	0.0	14,341.7	16,034.0	75,472.7	65,863.3
12-31-2021	5	0.9	0.0	0.0	737.6	0.0	13,750.6	12,218.7	87,691.4	74,241.5
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	13,505.2	7,055.3	94,746.7	78,643.2
12-31-2023	4	0.7	0.0	0.0	775.0	0.0	13,454.0	4,073.7	98,820.4	80,958.4
08-31-2024	4	0.7	0.0	0.0	529.6	0.0	8,780.2	1,387.9	100,208.3	81,685.7
SUBTOTAL			0.0	0.0	5,415.6	0.0	98,257.5	100,208.3	100,208.3	81,685.7
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	100,208.3	81,685.7
TOTAL OF 7.2 YRS			0.0	0.0	5,415.6	0.0	98,257.5	100,208.3	100,208.3	81,685.7

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	100,208.3
5.000	89,971.0
10.000	81,685.7
15.000	74,876.2
20.000	69,202.2
25.000	64,415.8
30.000	60,333.3
35.000	56,816.4
40.000	53,759.5
50.000	48,715.6

BASED ON ESCALATED PRICE AND COST PARAMETERS
LOW PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 11

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

PROVED DEVELOPED PRODUCING RESERVES

SERICA ENERGY PLC INTEREST

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD ENDING M-D-Y	GROSS RESERVES OIL/COND MBBL	GROSS RESERVES NGL MBBL	GROSS RESERVES GAS MMCF	NET RESERVES OIL/COND MBBL	NET RESERVES NGL MBBL	NET RESERVES GAS MMCF	AVERAGE PRICES OIL/COND $/BBL	AVERAGE PRICES NGL $/BBL	AVERAGE PRICES GAS $/MCF	GROSS REVENUE OIL/COND M$	GROSS REVENUE NGL M$	GROSS REVENUE GAS M$	GROSS REVENUE TOTAL M$
12-31-2017	1,104.5	0.0	7,391.0	198.8	25.9	1,303.8	60.49	46.87	7.123	12,026.3	1,214.5	9,286.8	22,527.6
12-31-2018	1,640.6	0.0	11,045.6	295.3	38.7	1,948.5	60.52	46.90	6.993	17,873.5	1,816.1	13,625.6	33,315.1
12-31-2019	1,087.7	0.0	7,343.8	195.8	25.7	1,295.4	61.00	47.26	6.826	11,942.3	1,216.6	8,842.1	22,001.1
12-31-2020	600.7	0.0	4,028.1	108.1	14.1	710.6	73.56	56.81	7.530	7,953.8	802.2	5,350.1	14,106.1
06-30-2021	148.8	0.0	1,050.8	26.8	3.7	185.4	79.31	61.18	7.530	2,124.7	225.4	1,395.6	3,745.7
SUBTOTAL	4,582.4	0.0	30,859.3	824.8	108.2	5,443.6	62.95	48.76	7.073	51,920.6	5,274.7	38,500.3	95,695.6
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,582.4	0.0	30,859.3	824.8	108.2	5,443.6	62.95	48.76	7.073	51,920.6	5,274.7	38,500.3	95,695.6
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	67,638.2	0.0	361,948.1										

PERIOD ENDING M-D-Y	NUMBER OF ACTIVE COMPLETIONS GROSS	NUMBER OF ACTIVE COMPLETIONS NET	NET DEDUCTIONS/EXPENDITURES TAXES PRODUCTION M$	TAXES AD VALOREM M$	CAPITAL COST M$	ABDNMNT COST M$	OPERATING EXPENSE M$	FUTURE NET REVENUE BEFORE INCOME TAXES UNDISCOUNTED PERIOD M$	UNDISCOUNTED CUM M$	DISC AT 10.000% CUM M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	5,944.2	16,072.7	16,072.7	15,706.4
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	10,931.7	21,698.5	37,771.2	35,543.7
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	10,305.0	10,994.0	48,765.2	44,709.2
12-31-2020	4	0.7	0.0	0.0	719.6	0.0	8,554.2	4,832.2	53,597.4	48,402.7
06-30-2021	2	0.4	0.0	0.0	368.8	0.0	2,666.8	710.0	54,307.4	48,901.0
SUBTOTAL			0.0	0.0	2,986.2	0.0	38,401.9	54,307.4	54,307.4	48,901.0
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	54,307.4	48,901.0
TOTAL OF 4.0 YRS			0.0	0.0	2,986.2	0.0	38,401.9	54,307.4	54,307.4	48,901.0

PRESENT WORTH PROFILE

DISC RATE %	CUM PW M$
0.000	54,307.4
5.000	51,425.5
10.000	48,901.0
15.000	46,672.5
20.000	44,691.6
25.000	42,919.7
30.000	41,325.6
35.000	39,884.0
40.000	38,574.0
50.000	36,282.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 12

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROBABLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	203.5	0.0	1,364.6	36.6	4.8	240.7	60.48	46.87	7.163	2,215.9	224.2	1,724.2	4,164.3
12-31-2018	510.6	0.0	3,384.0	91.9	11.9	596.9	60.55	46.92	6.942	5,565.6	556.6	4,143.8	10,266.0
12-31-2019	576.2	0.0	3,843.4	103.7	13.5	678.0	61.02	47.28	6.802	6,328.7	637.0	4,611.3	11,576.9
12-31-2020	695.8	0.0	4,702.5	125.2	16.5	829.5	73.56	56.81	7.530	9,212.8	936.5	6,245.8	16,395.1
12-31-2021	780.1	0.0	5,057.2	140.4	17.7	892.1	79.31	61.18	7.530	11,136.4	1,084.6	6,716.9	18,938.0
12-31-2022	632.1	0.0	4,202.2	113.8	14.7	741.3	85.06	65.55	7.530	9,678.6	965.6	5,581.4	16,225.6
12-31-2023	499.6	0.0	3,318.7	89.9	11.6	585.4	85.06	65.55	8.371	7,648.9	762.6	4,900.5	13,312.1
06-30-2024	214.6	0.0	1,421.8	38.6	5.0	250.8	87.22	67.19	8.602	3,368.9	334.9	2,157.6	5,861.4
SUBTOTAL	4,112.5	0.0	27,294.3	740.2	95.7	4,814.7	74.51	57.50	7.494	55,155.9	5,502.0	36,081.6	96,739.4
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,112.5	0.0	27,294.3	740.2	95.7	4,814.7	74.51	57.50	7.494	55,155.9	5,502.0	36,081.6	96,739.4
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,112.5	0.0	27,294.3										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES			PRESENT WORTH PROFILE	
ENDING	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%	DISC RATE	CUM PW
	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM		
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$	%	M$
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	461.4	3,702.9	3,702.9	3,611.4	0.000	52,345.8
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	1,330.5	8,935.6	12,638.5	11,729.0	5.000	45,734.0
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	2,067.7	9,509.3	22,147.7	19,583.1	10.000	40,427.6
12-31-2020	1	0.2	0.0	0.0	0.0	0.0	4,027.1	12,368.0	34,515.7	28,860.3	15.000	36,107.8
12-31-2021	2	0.4	0.0	0.0	368.8	0.0	8,457.1	10,112.0	44,627.8	35,785.0	20.000	32,545.7
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	10,630.2	4,839.4	49,467.1	38,817.5	25.000	29,574.2
12-31-2023	3	0.5	0.0	0.0	775.0	0.0	10,384.6	2,152.5	51,619.7	40,044.8	30.000	27,069.4
06-30-2024	3	0.5	0.0	0.0	397.2	0.0	4,738.1	726.2	52,345.8	40,427.6	35.000	24,937.7
											40.000	23,107.7
											50.000	20,143.9
SUBTOTAL			0.0	0.0	2,297.0	0.0	42,096.6	52,345.8	52,345.8	40,427.6		
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	52,345.8	40,427.6		
TOTAL OF 7.0 YRS			0.0	0.0	2,297.0	0.0	42,096.6	52,345.8	52,345.8	40,427.6		

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 13

NETHERLAND, SEWELL & ASSOCIATES, INC.

SERICA ENERGY PLC INTEREST

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

PROVED + PROBABLE (2P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,308.1	0.0	8,755.5	235.5	30.7	1,544.5	60.49	46.87	7.129	14,242.2	1,438.7	11,011.0	26,691.9
12-31-2018	2,151.2	0.0	14,429.7	387.2	50.6	2,545.4	60.53	46.91	6.981	23,439.1	2,372.7	17,769.4	43,581.1
12-31-2019	1,663.9	0.0	11,187.2	299.5	39.2	1,973.4	61.00	47.27	6.817	18,271.0	1,853.6	13,453.4	33,578.0
12-31-2020	1,296.5	0.0	8,730.5	233.4	30.6	1,540.1	73.56	56.81	7.530	17,166.5	1,738.7	11,595.9	30,501.1
12-31-2021	928.9	0.0	6,107.9	167.2	21.4	1,077.4	79.31	61.18	7.530	13,261.2	1,309.9	8,112.6	22,683.7
12-31-2022	632.1	0.0	4,202.2	113.8	14.7	741.3	85.06	65.55	7.530	9,678.6	965.6	5,581.4	16,225.6
12-31-2023	499.6	0.0	3,318.7	89.9	11.6	585.4	85.06	65.55	8.371	7,648.9	762.6	4,900.5	13,312.1
06-30-2024	214.6	0.0	1,421.8	38.6	5.0	250.8	87.22	67.19	8.602	3,368.9	334.9	2,157.6	5,861.4
SUBTOTAL	8,694.9	0.0	58,153.6	1,565.1	203.9	10,258.3	68.42	52.86	7.270	107,076.4	10,776.7	74,581.9	192,435.0
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	8,694.9	0.0	58,153.6	1,565.1	203.9	10,258.3	68.42	52.86	7.270	107,076.4	10,776.7	74,581.9	192,435.0
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	71,750.7	0.0	389,242.4										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	6,405.6	19,775.6	19,775.6	19,317.8
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	12,262.1	30,634.0	50,409.7	47,272.7
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	12,372.7	20,503.3	70,912.9	64,292.3
12-31-2020	5	0.9	0.0	0.0	719.6	0.0	12,581.3	17,200.2	88,113.1	77,263.0
12-31-2021	4	0.7	0.0	0.0	737.6	0.0	11,124.0	10,822.1	98,935.2	84,686.0
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	10,630.2	4,839.4	103,774.6	87,718.5
12-31-2023	3	0.5	0.0	0.0	775.0	0.0	10,384.6	2,152.5	105,927.1	88,945.8
06-30-2024	3	0.5	0.0	0.0	397.2	0.0	4,738.1	726.2	106,653.3	89,328.6
SUBTOTAL			0.0	0.0	5,283.2	0.0	80,498.5	106,653.3	106,653.3	89,328.6
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	106,653.3	89,328.6
TOTAL OF 7.0 YRS			0.0	0.0	5,283.2	0.0	80,498.5	106,653.3	106,653.3	89,328.6

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	106,653.3
5.000	97,159.4
10.000	89,328.6
15.000	82,780.3
20.000	77,237.3
25.000	72,493.9
30.000	68,395.0
35.000	64,821.7
40.000	61,681.7
50.000	56,426.9

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 14

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

POSSIBLE RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	281.9	0.0	1,851.5	50.7	6.5	326.6	60.49	46.87	7.145	3,068.9	304.2	2,333.6	5,706.7
12-31-2018	578.9	0.0	3,805.3	104.2	13.3	671.3	60.54	46.92	6.957	6,309.3	625.8	4,670.3	11,605.4
12-31-2019	566.2	0.0	3,727.7	101.9	13.1	657.6	61.01	47.27	6.796	6,217.7	617.7	4,468.4	11,303.9
12-31-2020	530.9	0.0	3,504.4	95.6	12.3	618.2	73.56	56.81	7.530	7,030.1	697.9	4,654.6	12,382.6
12-31-2021	566.8	0.0	3,904.0	102.0	13.7	688.7	79.31	61.18	7.530	8,092.4	837.3	5,185.3	14,115.0
12-31-2022	516.7	0.0	3,342.2	93.0	11.7	589.6	85.06	65.55	7.530	7,910.8	768.0	4,439.1	13,117.8
12-31-2023	449.8	0.0	2,917.6	81.0	10.2	514.7	85.06	65.55	8.371	6,886.8	670.4	4,308.3	11,865.5
12-31-2024	528.3	0.0	3,479.2	95.1	12.2	613.7	87.22	67.19	8.602	8,293.4	819.4	5,279.5	14,392.3
12-31-2025	545.1	0.0	3,631.7	98.1	12.7	640.6	89.43	68.87	8.840	8,773.8	876.8	5,663.0	15,313.5
04-30-2026	162.8	0.0	1,083.4	29.3	3.8	191.1	91.69	70.59	9.083	2,687.2	268.1	1,735.8	4,691.1
SUBTOTAL	4,727.3	0.0	31,247.0	850.9	109.5	5,512.0	76.71	59.21	7.754	65,270.4	6,485.7	42,737.8	114,493.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	4,727.3	0.0	31,247.0	850.9	109.5	5,512.0	76.71	59.21	7.754	65,270.4	6,485.7	42,737.8	114,493.9
CUM PROD	0.0	0.0	0.0										
ULTIMATE	4,727.3	0.0	31,247.0										

PERIOD	NUMBER OF ACTIVE COMPLETIONS		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES		
			TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%
ENDING			PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM
M-D-Y	GROSS	NET	M$	M$	M$	M$	M$	M$	M$	M$
12-31-2017	0	0.0	0.0	0.0	0.0	0.0	572.7	5,134.1	5,134.1	5,011.5
12-31-2018	0	0.0	0.0	0.0	0.0	0.0	1,291.1	10,314.3	15,448.4	14,395.2
12-31-2019	0	0.0	0.0	0.0	0.0	0.0	1,521.6	9,782.2	25,230.6	22,490.9
12-31-2020	0	0.0	0.0	0.0	0.0	0.0	1,760.4	10,622.2	35,852.8	30,479.8
12-31-2021	1	0.2	0.0	0.0	0.0	0.0	2,626.6	11,488.4	47,341.2	38,342.4
12-31-2022	0	0.0	0.0	0.0	0.0	0.0	2,875.1	10,242.8	57,584.0	44,705.0
12-31-2023	1	0.2	0.0	0.0	0.0	0.0	3,069.5	8,796.0	66,380.0	49,680.9
12-31-2024	1	0.2	0.0	0.0	397.2	0.0	8,238.4	5,756.7	72,136.8	52,657.6
12-31-2025	3	0.5	0.0	0.0	814.2	0.0	12,766.2	1,733.1	73,869.9	53,475.5
04-30-2026	3	0.5	0.0	0.0	278.2	0.0	4,293.8	119.2	73,989.0	53,528.0
SUBTOTAL			0.0	0.0	1,489.6	0.0	39,015.2	73,989.0	73,989.0	53,528.0
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	73,989.0	53,528.0
TOTAL OF 8.8 YRS			0.0	0.0	1,489.6	0.0	39,015.2	73,989.0	73,989.0	53,528.0

PRESENT WORTH PROFILE	
DISC RATE	CUM PW
%	M$
0.000	73,989.0
5.000	62,377.3
10.000	53,528.0
15.000	46,650.8
20.000	41,211.3
25.000	36,839.8
30.000	33,275.7
35.000	30,331.4
40.000	27,870.1
50.000	24,014.9

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 15

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY PROJECTION OF RESERVES AND REVENUE
AS OF JUNE 30, 2017

SERICA ENERGY PLC INTEREST

PROVED + PROBABLE + POSSIBLE (3P) RESERVES

SUMMARY - CERTAIN PROPERTIES
LOCATED IN ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA

PERIOD	GROSS RESERVES			NET RESERVES			AVERAGE PRICES			GROSS REVENUE			
ENDING	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	OIL/COND	NGL	GAS	TOTAL
M-D-Y	MBBL	MBBL	MMCF	MBBL	MBBL	MMCF	$/BBL	$/BBL	$/MCF	M$	M$	M$	M$
12-31-2017	1,589.9	0.0	10,607.1	286.2	37.2	1,871.1	60.49	46.87	7.132	17,311.1	1,742.9	13,344.7	32,398.7
12-31-2018	2,730.2	0.0	18,235.0	491.4	63.9	3,216.7	60.53	46.91	6.976	29,748.3	2,998.5	22,439.6	55,186.5
12-31-2019	2,230.1	0.0	14,914.8	401.4	52.3	2,631.0	61.01	47.27	6.812	24,488.7	2,471.3	17,921.9	44,881.9
12-31-2020	1,827.4	0.0	12,235.0	328.9	42.9	2,158.2	73.56	56.81	7.530	24,196.6	2,436.6	16,250.5	42,883.7
12-31-2021	1,495.8	0.0	10,011.9	269.2	35.1	1,766.1	79.31	61.18	7.530	21,353.6	2,147.2	13,297.8	36,798.7
12-31-2022	1,148.8	0.0	7,544.4	206.8	26.4	1,330.8	85.06	65.55	7.530	17,589.4	1,733.6	10,020.5	29,343.5
12-31-2023	949.4	0.0	6,236.3	170.9	21.9	1,100.1	85.06	65.55	8.371	14,535.7	1,433.0	9,208.9	25,177.6
12-31-2024	742.9	0.0	4,901.0	133.7	17.2	864.5	87.22	67.19	8.602	11,662.3	1,154.3	7,437.1	20,253.8
12-31-2025	545.1	0.0	3,631.7	98.1	12.7	640.6	89.43	68.87	8.840	8,773.8	876.8	5,663.0	15,313.5
04-30-2026	162.8	0.0	1,083.4	29.3	3.8	191.1	91.69	70.59	9.083	2,687.2	268.1	1,735.8	4,691.1
SUBTOTAL	13,422.2	0.0	89,400.6	2,416.0	313.4	15,770.3	71.34	55.08	7.439	172,346.8	17,262.4	117,319.7	306,928.9
REMAINING	0.0	0.0	0.0	0.0	0.0	0.0	0.00	0.00	0.000	0.0	0.0	0.0	0.0
TOTAL	13,422.2	0.0	89,400.6	2,416.0	313.4	15,770.3	71.34	55.08	7.439	172,346.8	17,262.4	117,319.7	306,928.9
CUM PROD	63,055.9	0.0	331,088.8										
ULTIMATE	76,478.1	0.0	420,489.4										

PERIOD	NUMBER OF		NET DEDUCTIONS/EXPENDITURES					FUTURE NET REVENUE BEFORE INCOME TAXES			PRESENT WORTH PROFILE	
ENDING	ACTIVE COMPLETIONS		TAXES		CAPITAL	ABDNMNT	OPERATING	UNDISCOUNTED		DISC AT 10.000%	DISC RATE	CUM PW
	GROSS	NET	PRODUCTION	AD VALOREM	COST	COST	EXPENSE	PERIOD	CUM	CUM		
M-D-Y			M$	M$	M$	M$	M$	M$	M$	M$	%	M$
12-31-2017	5	0.9	0.0	0.0	510.7	0.0	6,978.3	24,909.7	24,909.7	24,329.3	0.000	180,642.3
12-31-2018	5	0.9	0.0	0.0	685.0	0.0	13,553.2	40,948.3	65,858.0	61,667.9	5.000	159,536.7
12-31-2019	5	0.9	0.0	0.0	702.1	0.0	13,894.3	30,285.5	96,143.5	86,783.3	10.000	142,856.6
12-31-2020	5	0.9	0.0	0.0	719.6	0.0	14,341.7	27,822.4	123,966.0	107,742.8	15.000	129,431.1
12-31-2021	5	0.9	0.0	0.0	737.6	0.0	13,750.6	22,310.5	146,276.4	123,028.4	20.000	118,448.6
12-31-2022	4	0.7	0.0	0.0	756.1	0.0	13,505.2	15,082.1	161,358.6	132,423.5	25.000	109,333.8
12-31-2023	4	0.7	0.0	0.0	775.0	0.0	13,454.0	10,948.6	172,307.1	138,626.7	30.000	101,670.6
12-31-2024	4	0.7	0.0	0.0	794.4	0.0	12,976.5	6,482.9	178,790.0	141,986.2	35.000	95,153.0
12-31-2025	3	0.5	0.0	0.0	814.2	0.0	12,766.2	1,733.1	180,523.1	142,804.1	40.000	89,551.8
04-30-2026	3	0.5	0.0	0.0	278.2	0.0	4,293.8	119.2	180,642.3	142,856.6	50.000	80,441.7
SUBTOTAL			0.0	0.0	6,772.8	0.0	119,513.7	180,642.3	180,642.3	142,856.6		
REMAINING			0.0	0.0	0.0	0.0	0.0	0.0	180,642.3	142,856.6		
TOTAL OF 8.8 YRS			0.0	0.0	6,772.8	0.0	119,513.7	180,642.3	180,642.3	142,856.6		

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

BASED ON ESCALATED PRICE AND COST PARAMETERS
HIGH PRICE CASE

Figure 16

REVENUE, TAXES, AND COSTS (M$)
SERICA ENERGY PLC
ERSKINE FIELD
UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

LOW AND HIGH PRICE CASES

Case/Category	Working Interest Gross Revenue	Capital Costs	Abandonment Costs[1]	Operating Costs	Future Net Revenue Before Income Tax Discounted at 0%	Future Net Revenue Before Income Tax Discounted at 10%	United Kingdom Corporate Income Taxes	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 0%	Future Net Revenue After United Kingdom Corporate Income Taxes Discounted at 10%
Low Price Case									
Proved Developed Producing	62,504.5	2,257.6	0.0	31,621.0	28,626.0	26,227.2	0.0	28,626.0	26,227.2
Probable	57,520.4	1,475.5	0.0	28,482.0	27,562.9	22,348.7	0.0	27,562.9	22,348.7
Proved + Probable (2P)	120,024.8	3,733.0	0.0	60,103.0	56,188.8	48,575.9	0.0	56,188.8	48,575.9
Possible	83,856.6	1,682.6	0.0	38,154.5	44,019.5	33,109.9	0.0	44,019.5	33,109.9
Proved + Probable + Possible (3P)	203,881.4	5,415.6	0.0	98,257.5	100,208.3	81,685.7	0.0	100,208.3	81,685.7
High Price Case									
Proved Developed Producing	95,695.6	2,986.2	0.0	38,401.9	54,307.4	48,901.0	0.0	54,307.4	48,901.0
Probable	96,739.4	2,297.0	0.0	42,096.6	52,345.8	40,427.6	0.0	52,345.8	40,427.6
Proved + Probable (2P)	192,435.0	5,283.2	0.0	80,498.5	106,653.3	89,328.6	0.0	106,653.3	89,328.6
Possible	114,493.9	1,489.6	0.0	39,015.2	73,989.0	53,528.0	11,856.9	62,132.1	40,582.0
Proved + Probable + Possible (3P)	306,928.9	6,772.8	0.0	119,513.7	180,642.3	142,856.6	11,856.9	168,785.4	129,910.6

(1) Serica is not liable for abandonment costs up to a maximum value that exceeds its current estimates of abandonment costs.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 17

SUMMARY OF UNRISKED CONTINGENT OIL RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA AND IN IRISH WATERS IN THE ATLANTIC OCEAN
AS OF JUNE 30, 2017

			Unrisked Contingent Oil Resources (MBBL)					
			Gross (100%)			Working Interest		
Subclass/Area/Field or Discovery	Operator Name	Risk Factor[2] (%)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Development Pending								
United Kingdom Sector of the Central North Sea								
Columbus Field	Serica Energy (UK) Limited	85	1,269.2	2,793.7	3,636.2	634.6	1,396.9	1,818.1
Development Not Viable								
Irish Waters in the Atlantic Ocean								
Bandon Discovery	Serica Energy Slyne B.V.	0	0.0	0.0	0.0	0.0	0.0	0.0
Total			1,269.2	2,793.7	3,636.2	634.6	1,396.9	1,818.1

(1) These volumes represent only the portions of the reservoirs that lie within the boundaries of the respective lease areas.

(2) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

Source: Netherland, Sewell & Associates, Inc.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 18

SUMMARY OF UNRISKED CONTINGENT GAS RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA AND IN IRISH WATERS OF THE ATLANTIC OCEAN
AS OF JUNE 30, 2017

			Unrisked Contingent Gas Resources (MMCF)					
			Gross (100%)			Working Interest		
Subclass/Area/Field or Discovery	Operator Name	Risk Factor[2] (%)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)	Low Estimate (1C)	Best Estimate (2C)	High Estimate (3C)
Development Pending								
United Kingdom Sector of the Central North Sea								
Columbus Field	Serica Energy (UK) Limited	85	28,857.3	63,533.2	82,284.1	14,428.7	31,766.6	41,142.1
Development Not Viable								
Irish Waters in the Atlantic Ocean								
Bandon Discovery	Serica Energy Slyne B.V.	0	0.0	0.0	0.0	0.0	0.0	0.0
Total			28,857.3	63,533.2	82,284.1	14,428.7	31,766.6	41,142.1

(1) These volumes represent only the portions of the reservoirs that lie within the boundaries of the respective lease areas.
(2) The risk factor for contingent resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the contingent resources refers to the PRMS term "chance of development".

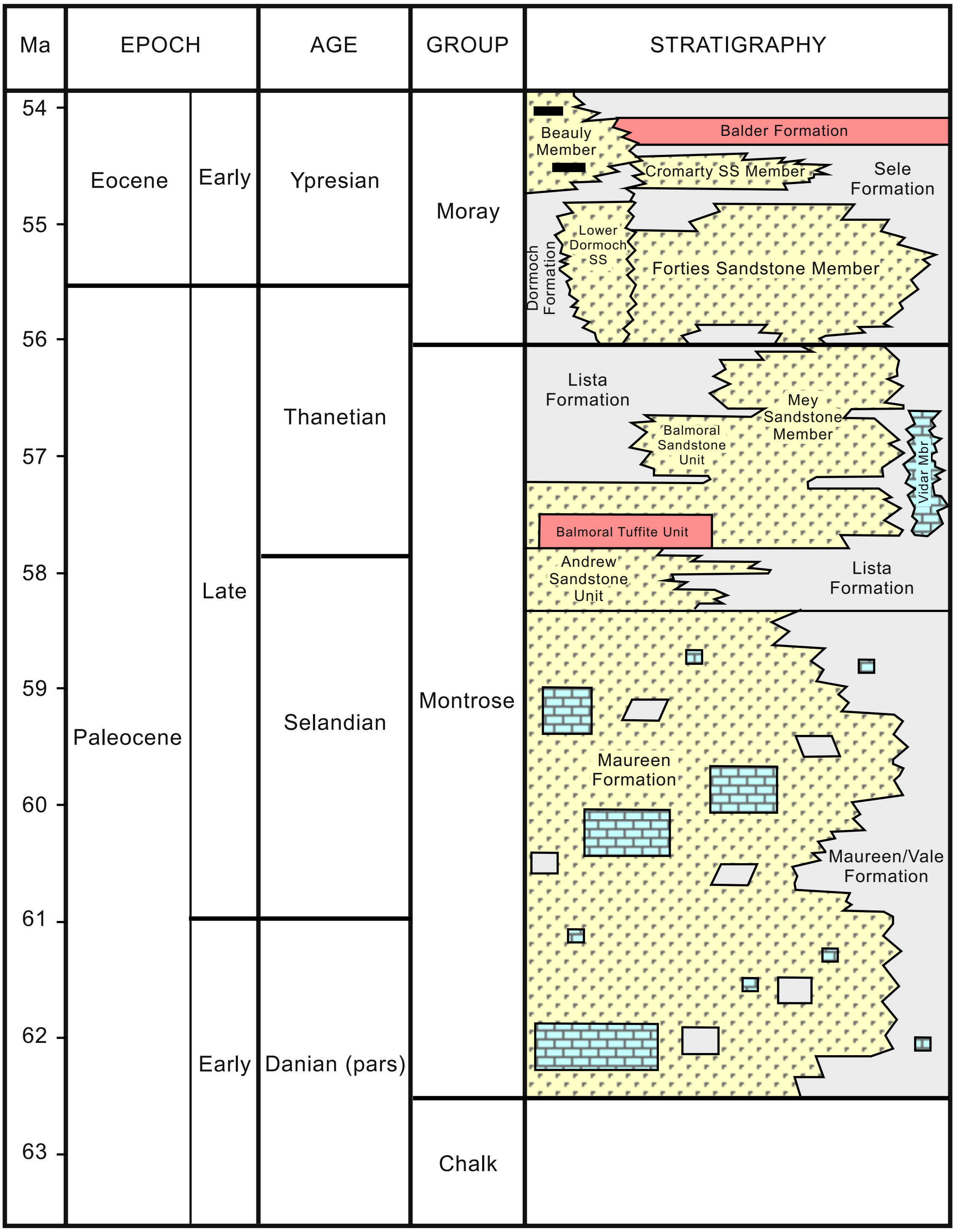
Source: Netherland, Sewell & Associates, Inc.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 19

NSAI NETHERLAND, SEWELL & ASSOCIATES, INC.

Stratigraphic Column
Columbus Field
United Kingdom Sector of the Central North Sea



Adapted from "The Millennium Atlas, Fig. 14.2" by Ahmadi et al., 2003.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions. Figure 20

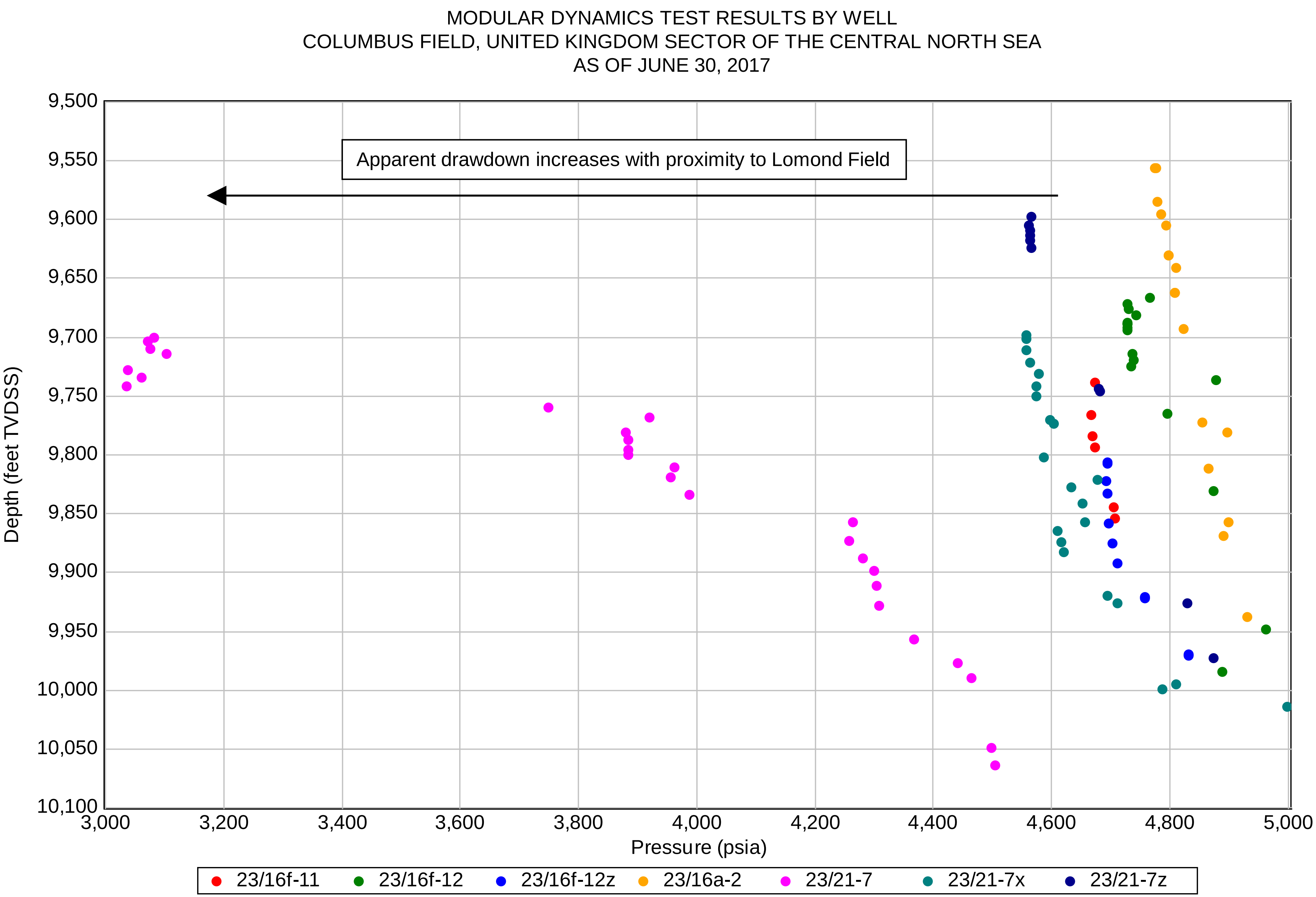
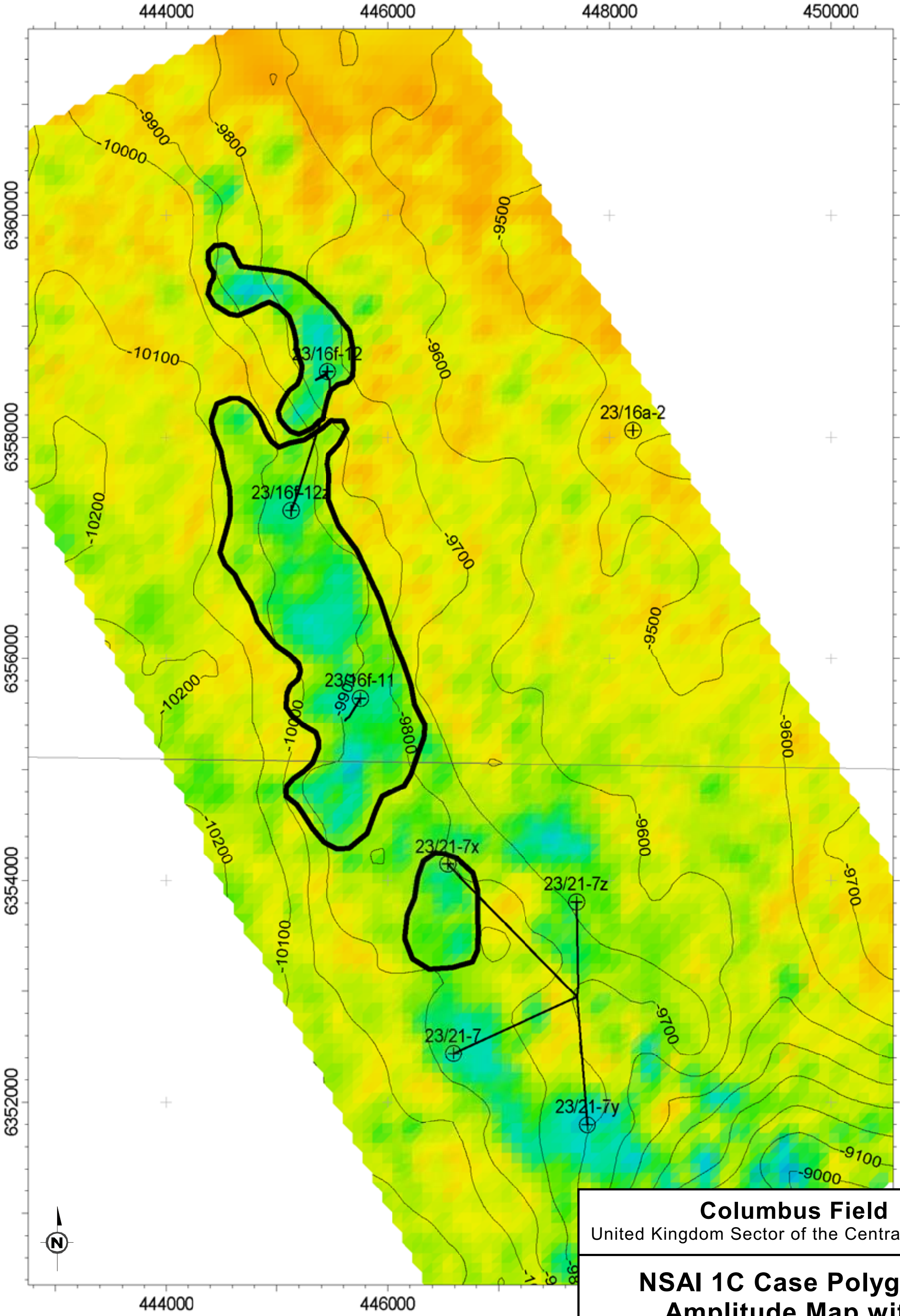


Figure 21

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

NETHERLAND, SEWELL & ASSOCIATES, INC.



Columbus Field
United Kingdom Sector of the Central North Sea

NSAI 1C Case Polygons
Amplitude Map with
Depth Structure (Top F-4 Zone)

Contour Interval: 100 feet

SCALE IN METERS
0 500 1,000 2,000

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 22

SUMMARY OF UNRISKED PROSPECTIVE OIL RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN IRISH WATERS IN THE ATLANTIC OCEAN AND IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

			Unrisked Prospective Oil Resources (MMBBL)					
			Gross (100%)			Working Interest		
Area/Prospect	Operator Name	Risk Factor[2] (%)	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Irish Waters in the Atlantic Ocean								
Achill	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Bandon South	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Boyne Sherwood	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Boyne Suisnish	Serica Energy Slyne B.V.	20	5.6	20.1	76.7	5.6	20.1	76.7
Liffey Sherwood	Serica Energy Slyne B.V.	26	0.0	0.0	0.0	0.0	0.0	0.0
Liffey Suisnish	Serica Energy Slyne B.V.	20	30.3	128.2	526.7	30.3	128.2	526.7
United Kingdom Sector of the Central North Sea								
Rowallan Pentland	Eni (UK) Ltd	22	3.5	8.8	20.0	0.5	1.3	3.0
Rowallan Triassic	Eni (UK) Ltd	22	10.0	33.0	113.4	1.5	4.9	17.0
Total			49.4	190.0	736.9	37.9	154.6	623.4

Notes: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding. Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of discovery".

Source: Netherland, Sewell & Associates, Inc.

Figure 23

NETHERLAND, SEWELL & ASSOCIATES, INC.

SUMMARY OF UNRISKED PROSPECTIVE GAS RESOURCES[1]
SERICA ENERGY PLC INTEREST
LOCATED IN IRISH WATERS IN THE ATLANTIC OCEAN AND IN THE UNITED KINGDOM SECTOR OF THE CENTRAL NORTH SEA
AS OF JUNE 30, 2017

			Unrisked Prospective Gas Resources (BCF)					
			Gross (100%)			Working Interest		
Area/Prospect	Operator Name	Risk Factor[2] (%)	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
Irish Waters in the Atlantic Ocean								
Achill	Serica Energy Slyne B.V.	26	120.7	252.7	516.5	120.7	252.7	516.5
Bandon South	Serica Energy Slyne B.V.	26	6.7	26.9	101.7	6.7	26.9	101.7
Boyne Sherwood	Serica Energy Slyne B.V.	26	60.8	180.2	528.5	60.8	180.2	528.5
Boyne Suisnish	Serica Energy Slyne B.V.	20	1.4	5.5	22.1	1.4	5.5	22.1
Liffey Sherwood	Serica Energy Slyne B.V.	26	52.6	180.4	626.7	52.6	180.4	626.7
Liffey Suisnish	Serica Energy Slyne B.V.	20	7.6	34.0	147.4	7.6	34.0	147.4
United Kingdom Sector of the Central North Sea								
Rowallan Pentland	Eni (UK) Ltd	22	54.4	118.7	259.9	8.2	17.8	39.0
Rowallan Triassic	Eni (UK) Ltd	22	134.1	422.4	1,463.9	20.1	63.4	219.6
Total			438.3	1,220.9	3,666.7	278.1	760.8	2,201.5

Notes: Totals are the arithmetic sum of multiple probability distributions and may not add because of rounding. Totals of unrisked prospective resources beyond the prospect level are not reflective of volumes that can be expected to be recovered and are shown for convenience only. Because of the geologic risk associated with each prospect, meaningful totals beyond this level can be defined only by summing risked prospective resources. Such risk is often significant.

(1) These volumes represent only the portions of the prospects that lie within the boundaries of the respective lease and/or license areas.

(2) The risk factor for prospective resources refers to the estimated chance, or probability, that the volumes will be commercially extracted. For the purposes of this report, the risk factor for the prospective resources refers to the PRMS term "chance of discovery".

Source: Netherland, Sewell & Associates, Inc.

All estimates and exhibits herein are part of this NSAI report and are subject to its parameters and conditions.

Figure 24

PART VII – UNAUDITED HISTORICAL FINANCIAL INFORMATION ON THE BKR ASSETS

	Six months ended 30 June 2017	Year ended 31 December 2016	Year ended 31 December 2015	Year ended 31 December 2014
	US$'000	*US$'000*	*US$'000*	*US$'000*
Revenue	**130,059**	**159,036**	**207,891**	**118,098**
Production expenditure	(19,115)	(40,786)	(62,172)	(75,663)
Other Government take	(739)	(672)	(1,546)	(1,639)
Other operating costs	(1,786)	(5,531)	(8,638)	(1,635)
Transportation costs	(31,859)	(51,705)	(68,857)	(13,503)
Insurance costs	(2,736)	(5,987)	(20,489)	(21,500)
FX loss/(gain)	370	(4,544)	(115)	(3,138)
Operating expenditure	**(55,864)**	**(109,226)**	**(161,817)**	**(117,078)**
EBITDA	**74,195**	**49,810**	**46,075**	**1,021**
Impairment	30,898	91,600	133,148	(407,696)
Depreciation	(31,990)	(52,376)	(40,822)	(40,677)
Decommissioning accretion	(598)	(1,776)	(2,302)	(3,162)
Profit Before Tax	**72,504**	**87,257**	**136,099**	**(450,514)**

The unaudited historic financial information on the BKR Assets, presented in this document, has been compiled on the following basis:

Revenue

Revenue predominantly represents the sale of produced products from the Bruce, Keith and Rhum fields in each respective period. Product revenue is recognised on an entitlement basis and not on a lifting basis. Therefore, oil and NGL revenue is calculated as actual liftings revenue adjusted for the change in the underlift or overlift balance during the period to derive the entitlement revenue for the period. Gas is accounted for on a sales basis. Also included in reported revenue is the net income which the Bruce field receives in the form of cost share (previously tariff) from the Rhum field.

A breakdown of the revenue by aggregated product across the BKR Assets can be found within Part II (*Further Information on the BKR Assets*).

Operating expenditure

This is comprised of production expenditure covering onshore manpower and overheads, offshore manpower, repairs and maintenance, engineering services and subsea works / drilling and logistics and platform services. The government take relates principally to the costs associated with licence fees. Other operating expenditure covers the associated upstream technology and research and development costs allocated to the BKR Assets. Transportation costs relate to costs associated with inter-field and Frigg pipeline costs and tariffs as well as blending costs. The operating expenditure also covers insurance costs allocated to the BKR Assets as well as any FX gains / losses associated with operations experienced in the periods.

Impairment, Depreciation and Decommissioning accretion

Non-cash items of impairment, depreciation and accretion of decommissioning provisions have also been included as part of the BKR Assets unaudited historic financial information.

It should be noted that the impairment charge of US$407.7 million in respect of the year ended 31 December 2014 is a significant charge which was driven by declining commodity prices in the period, Rhum restrictions caused by high levels of CO_2. As this has subsequently been resolved and the commodity price environment has improved the BKR Assets when aggregated have been partially written back as shown above by the write back of US$133.1 million for the year ended 31 December 2015 and of US$91.6 million in the year ended 31 December 2016.

Basis of preparation

Audited Financial Statements are not prepared at the BKR Asset or field level by BP and therefore individual field level financial information have been extracted from BP's SAP system and has been aggregated to form the above unaudited historical financial information table. Pro forma and consolidation adjustments have been overlaid as part of the aggregation, but a full *pro forma* and consolidation analysis has not been undertaken and the profit and loss information is not part of a full set of financial statements. It should be noted that neither the aggregated profit and loss information, nor the field level profit and loss information, has been audited.

As the BKR Assets are part of a larger business segment, BP does not prepare full financial statements for the any of the BKR Assets. For the purposes of the Acquisition individual field level profit and loss accounts have been extracted from BP's SAP systems and aggregated to form the above BKR Assets unaudited profit and loss. Neither the aggregated profit and loss nor the individual field profit and loss accounts are subject to external audit and they are not prepared in accordance with International Financial and Report Standards (IFRS). Certain *pro forma* and consolidation adjustments have been overlaid to the profit and loss accounts extracted from the SAP system.

PART VIII – HISTORICAL FINANCIAL INFORMATION ON SERICA

1. Background

The consolidated financial statements of the Serica Group for the year ended 31 December 2014, as set out in the annual report and accounts of the Serica Group for 2014, the consolidated financial statements of the Serica Group for the year ended 31 December 2015, as set out in the annual report and accounts of the Serica Group for 2015, the consolidated financial statements of the Serica Group for the year ended 31 December 2016, as set out in the annual report and accounts of the Serica Group for 2016 and the unaudited consolidated interim financial statements of the Serica Group for the six months ended 30 June 2017, as set out in the interim report of the Serica Group for the six months ended 30 June 2017, are incorporated by reference into this document. The audit reports for each of the financial years ended 31 December 2014, 31 December 2015 and 31 December 2016 were unqualified. The consolidated financial statements for the financial years ended 31 December 2014, 31 December 2015 and 31 December 2016 and for the six months ended 30 June 2017 (unaudited) were prepared in accordance with IFRS.

2. Cross reference list

The following list is intended to enable investors to identify easily specific items of information which have been incorporated by reference into this document. A copy of each of these documents incorporated by reference into this document can be accessed on the Company's website at http:// http://www.serica-energy.com/.

2.1 IFRS financial statements for the financial year ended 31 December 2014 and the audit report thereon

The page numbers below refer to the relevant pages of the annual report and accounts of the Serica Group for the financial year ended 31 December 2014:

Section	*Page number(s)*
Independent auditor's report	33 to 34
Group income statement	35
Balance sheet	36
Statement of changes in equity	37
Cash flow statement	38
Notes to the financial statements	39 to 77

2.2 IFRS financial statements for the financial year ended 31 December 2015 and the audit report thereon

The page numbers below refer to the relevant pages of the annual report and accounts of the Serica Group for the financial year ended 31 December 2015:

Section	*Page number(s)*
Independent auditor's report	23 to 24
Group income statement	25
Balance sheet	26
Statement of changes in equity	27
Cash flow statement	28
Notes to the financial statements	29 to 61

2.3 IFRS financial statements for the financial year ended 31 December 2016 and the audit *report thereon*

The page numbers below refer to the relevant pages of the annual report and accounts of the Serica Group for the financial year ended 31 December 2016:

Section	*Page number(s)*
Independent auditor's report	21 to 22
Group income statement	23
Balance sheet	24
Statement of changes in equity	25
Cash flow statement	26
Notes to the financial statements	27 to 58

2.4 Unaudited IFRS financial statements for the six months ended 30 June 2017

The page numbers below refer to the relevant pages of the interim report and accounts of the Serica Group for the six months ended 30 June 2017:

PART IX – UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE ENLARGED GROUP

The unaudited *pro forma* balance sheet set out below has been prepared for the purpose of illustrating the effect of the Acquisition on the balance sheet of the Company as at 30 June 2017 as if it had taken place on that date. The unaudited *pro forma* balance sheet has been prepared for illustrative purposes only and, by its nature, addresses a hypothetical situation and, does not, therefore, represent the Company's or the Enlarged Group's actual financial position or results. The unaudited *pro forma* balance sheet has been prepared on the basis set out in the notes below and in accordance with Schedule Two of the AIM Rules for Companies.

The unaudited *pro forma* balance sheet does not constitute financial statements within the meaning of Section 434 of the Companies Act.

Unaudited Pro Forma Balance Sheet

		Adjustments					
	Serica net assets as at 30 June 2017 (Note 1)	**Prepayment Facility drawing for hedging premiums (Note 2)**	**Prepayment Facility drawing for Initial Consideration (Note 3)**	**BKR Assets acquisition Initial Consideration (Note 4)**	**BKR Assets acquisition and contingent / deferred consideration (Note 5)**	**Deferred tax adjustments (Note 6)**	**Enlarged Group *pro forma* as at 30 June 2017**
	US$'000	*US$'000*	*US$'000*	*US$'000*	*US$'000*	*US$'000*	*US$'000*
Non-current assets							
Property, plant and equipment	7,608	—	—	16,640	188,129	—	212,377
Exploration & evaluation assets	52,742	—	—	—	—	—	52,742
Deferred tax asset	9,115	—	—	—	—	—	9,115
Total non-current assets	69,465	—	—	16,640	188,129	—	274,234
Current assets							
Inventory	396	—	—	—	—	—	396
Trade and other receivables	4,931	3,735	—	—	—	—	8,666
Cash and cash equivalents	25,083	—	16,640	(16,640)	13,394	—	38,477
Term deposits	5,600	—	—	—	—	—	5,600
Total current assets	36,010	3,735	16,640	(16,640)	13,394	—	53,139
Total assets	**105,475**	**3,735**	**16,640**	**—**	**201,523**	**—**	**327,373**
Current liabilities							
Trade and other payables	(4,899)	—	—	—	—	—	(4,899)
Contingent/ deferred consideration payable	—	—	—	—	(188,853)	—	(188,853)
Total current liabilities	(4,899)	—	—	—	(188,853)	—	(193,752)
Non-current liabilities							
Deferred income tax	—	—	—	—	—	(10,984)	(10,984)
Transaction facility	—	(3,735)	(16,640)	—	—	—	(20,375)
Trade and other payables	(2,924)	—	—	—	—	—	(2,924)
Provisions	(2,190)	—	—	—	—	—	(2,190)
Total non-current liabilities	(5,114)	(3,735)	(16,640)	—	—	(10,984)	(36,473)
Total liabilities	(10,013)	(3,735)	(16,640)	—	(188,853)	(10,984)	(230,225)
Net assets	**95,462**	**—**	**—**	**—**	**12,670**	**(10,984)**	**97,148**
Capital and reserves							
Called up share capital	229,308	—	—	—	—	—	229,308
Other reserves	20,739	—	—	—	—	—	20,739
Reserves	(154,585)	—	—	—	12,670	(10,984)	(152,899)
Total equity	**95,462**	**—**	**—**	**—**	**12,670**	**(10,984)**	**97,148**

Notes:

The unaudited *pro forma* balance sheet of the Enlarged Group as at 30 June 2017 (the **"Pro Forma"**) has been prepared on the basis that the acquisition of the BKR Assets by Serica will be treated as an acquisition in accordance with IFRS 3 – Business Combinations. The calculation of the actual consideration to be reflected in the first set of consolidated financial statements prepared by Serica after the transaction has completed will be based on available information at the date of Completion. This may be materially different from the Pro Forma. The Pro Forma has been prepared for illustrative purposes only, to illustrate the effect on assets and liabilities of the Enlarged Group as at 30 June 2017 as if the Acquisition had taken place on that date.

A foreign exchange rate of £1 = US$1.30 has been used in the Pro Forma.

1. The net assets of Serica as at 30 June 2017 have been extracted without material adjustment from the unaudited consolidated interim financial statements of Serica for the six months ended 30 June 2017, as incorporated by reference in Part VIII (*Historical Financial Information of Serica*).

The adjustments arising as a result of the acquisition of the BKR Assets are set out below:

2. As set out in paragraph 11.1(d) of Part XII (*Additional Information*), Serica UK entered into a Prepayment Facility dated 21 November 2017 with BP Gas to provide for drawings to cover the Initial Consideration of £12.8 million (US$16.6 million) and the cost of premiums payable for gas price puts which have been purchased by Serica UK in conjunction with signing the Acquisition Agreement. This adjustment reflects a drawing of £2.9 million (US$3.7 million) to cover the cost of premiums acquired on 21 November 2017.
3. As set out in paragraph 11.1(d) of Part XII (*Additional Information*), Serica UK entered into a Prepayment Facility dated 21 November 2017 with BP Gas to provide for drawings to cover the Initial Consideration of £12.8 million (US$16.6 million) and the cost of premiums payable for gas price puts which have been purchased by Serica UK in conjunction with signing the Acquisition Agreement. This adjustment reflects a drawing to cover the Initial Consideration at Completion.
4. Initial Consideration of £12.8 million (US$16.6 million) is paid at Completion.
5. The acquisition accounting adjustments relate to the fair value measurement of the acquired assets and liabilities of the BKR Assets on the basis that the transaction will be treated as an acquisition in accordance with IFRS 3 – Business Combinations. The adjustments in respect of plant, property and equipment relate to the assessment of the fair value of interests in the acquired oil and gas assets. These have been based on economic models prepared in respect of those assets using information currently available which includes forecast data including oil and gas production, production sales contracts, future capital expenditure and operating expenditure. The calculation of contingent/deferred consideration is also based on the same economic models prepared in respect of those assets using information currently available which includes forecast data including oil and gas production, production sales contracts, future capital expenditure, operating and other expenditure relevant to the calculation. Discount rates have been applied to both the fair value measurement and contingent/deferred consideration calculations reflecting specific risks associated with the transaction. The adjustment also reflects the interim adjustment payable to Serica for the period from the economic effective date of the Acquisition, 1 January 2018, to the assumed Completion, in mid-year 2018.

   Transaction costs expected to be incurred by Serica are approximately £1.25 million (US$1.6 million) and have been recognised as an operating expense and deducted from cash and cash equivalents in the Pro Forma.
6. A deferred income tax liability of US$11.0 million has been recognised, calculated by applying the prevailing combined corporate and supplementary charge tax rate of 40% in respect of the difference between the fair value of property, plant and equipment recognised, and the tax carrying value associated with the tax deductible elements of the estimated contingent / deferred consideration.

PART X – FURTHER INFORMATION ON THE OFFSHORE OIL AND GAS INDUSTRY IN THE UK

1. United Kingdom Continental Shelf overview

The North Sea contains Western Europe's largest oil and natural gas reserves. The commercial production of oil and gas in the UKCS dates back to the 1960s. Since 1967, approximately 43 billion boe have been extracted from the UKCS. The volume of production of oil and gas reached a peak in the years 1999 and 2000 respectively, and has seen a decline since then. However, there are still considerable oil and gas resources remaining: the remaining recoverable resource potential ranges between 10 and 20 billion boe, broken down into:

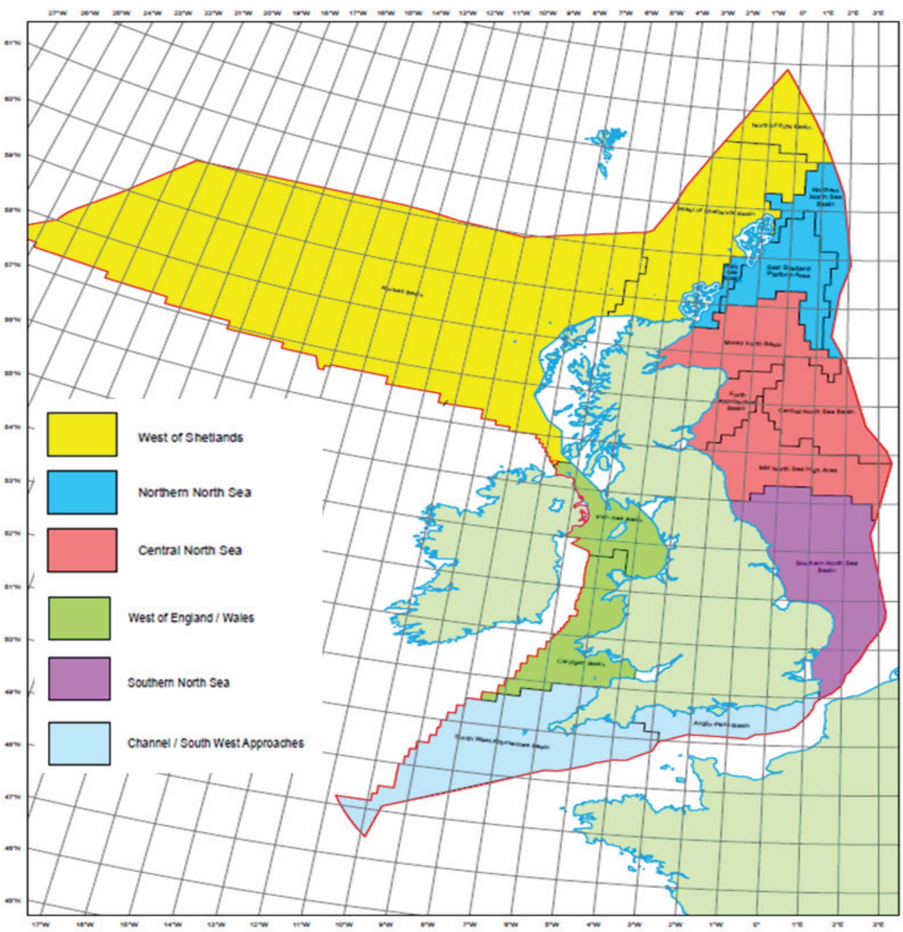
- 6-9 billion boe in existing reserves;
- 2-5 billion boe in potential additional resources; and
- 2-6 billion boe in yet-to-find potential.

2. The regulatory regime

2.1 Introduction

This section provides a brief overview of the regulatory regime on the UKCS as it applies to the Enlarged Group's North Sea assets.

The ability to exploit offshore petroleum resources in the UK is limited to the UKCS. The UKCS is split into six principal petroleum provinces (and various sub-areas), as shown on the map below. Petroleum exploration and production occurs in all six provinces, although there is minimal activity in the Channel/South West Approaches.



2.2 Recent changes to the regulatory regime

The UK Government has recently implemented significant changes to the regulatory regime that applies to the upstream oil and gas industry. In an effort to revitalise the UK upstream oil and gas industry, in June 2013 the Secretary of State for Energy and Climate Change (the head of the department formerly responsible for energy policy) asked Sir Ian Wood to lead a review of the challenges faced by the offshore upstream industry, and to make recommendations for reform. The final report, outlining the findings and recommendations of the Wood Review, was published in February 2014. The recommendations of the Wood Review were supported by both the UK Government and industry. Two of the key recommendations of the Wood Review (amongst others) were that a new strategy is needed for maximising economic recovery in the UKCS (referred to as "**MER UK**") and that a new, independent regulator should be established. These recommendations have now been fully implemented into the UKCS regulatory regime, with the establishment of the new Oil and Gas Authority ("**OGA**") to replace many of the functions undertaken by the DECC (whose functions relating to energy matters have now been taken over by BEIS and the enshrining of the MER UK principle in legislation).

2.3 Regulatory bodies

As mentioned above, the current regulator principally responsible for the promotion and regulation of the petroleum industry in the UK is the OGA. As a regulator, the OGA has taken over the licensing and regulatory oversight functions previously undertaken by DECC/BEIS on behalf of the Secretary of State.

While the OGA has taken over responsibility for upstream oil and gas regulation, BEIS is still responsible for overall energy policy. A framework agreement governs the relationship between the OGA and BEIS.

Notwithstanding the transfer of powers to the OGA, there are two key areas in relation to which BEIS retains responsibility, being: (i) the administration and enforcement of environmental legislation applying to offshore oil and gas activities; and (ii) the decommissioning regime under the Petroleum Act.

Other relevant bodies responsible for regulating the UKCS industry include:

- the HSE (which oversees health and safety);
- the OSPAR Commission (which oversees the UK's international obligations on the protection of the marine environment and decommissioning); and
- BEIS and the HSE, working in partnership, have established the OSDR to act as the UK's Competent Authority for the purposes of the EU Offshore Safety Directive (2013/30/EU).

2.4 Licensing system

The principal legislation governing the development of oil and natural gas reserves is the Petroleum Act. Under the Petroleum Act, all rights to petroleum including the rights to "search for, bore for and get" petroleum are vested in the Crown.

Until recently, the Petroleum Act empowered the Secretary of State to grant licences to explore for, develop and produce oil and natural gas reserves. However, the Petroleum (Transfer of Functions) Regulations 2016 have now vested the power in the OGA.

In awarding licences, regard must be given to the Hydrocarbons Licensing Directive Regulations 1995, which implement certain EU directives in relation to hydrocarbon licensing that were passed in 1994. Licences are usually awarded in licensing rounds where a large number of blocks are made available. The 30th offshore licensing round was launched in July 2017. "Out of round" licences may also be granted in certain circumstances.

Licences take the form of a deed, pursuant to which the licensee is bound to observe the conditions of the licence. The conditions of the licence (referred to as the model clauses) are published in secondary legislation. The licence governs the relationship between the OGA and the licensee and despite licences being capable of being held by several companies working together, in legal terms there is only ever a single licensee. As such the licence states that each company is jointly and severally liable for all liabilities and obligations arising under it.

2.5 **Different types of licences**

The OGA currently grants two types of offshore licence:

- the exploration licence – under which licensees are granted a non-exclusive right for a three year term to conduct seismic surveys and shallow drilling on areas that are not already covered by a production licence; and
- the seaward production licence – under which licensees are granted an exclusive right to search for, bore for and extract petroleum from the UKCS within the licensed area for the full life of the field.

Each seaward production licence runs for three successive terms – the initial, second and third term. The licensee can only move on to the next term if certain requirements are met.

The standard seaward production licence, often referred to as a "*Traditional Licence*", has been the most common form of production licence issued. The licence will only continue into a second term if the agreed minimum exploration work obligations (the "**Work Programme**") have been completed and if 50% of the acreage has been relinquished. However, in recent years it was recognised that the Traditional Licence may not be appropriate in all cases. For this reason, until recently, a number of variations of seaward production licences were also issued to licensees, as follows:

(a) The "*Promote Licence*" has allowed smaller and start-up companies to obtain a production licence first and gain the necessary operating and financial capacity later. During the first two years the annual rental rate is reduced by 90% and the financial and technical capability requirements for licensees are relaxed. If the regulator decides the licensee has not established the requisite financial, technical and environmental capabilities or the licensee has failed to make a firm drilling (or agreed equivalent equally substantive activity) commitment by the end of the two year period, the licence terminates.

(b) The "*Frontier Licence*" was designed to address the complexities in sourcing petroleum in remote areas of the UKCS and allow searching over a large area to look for a broader range of prospects. During the initial term where an early surrender area and period are specified the licensee must notify and surrender any specified area at the end of the third year and if it fails to comply the licence will expire. Where the licence contains a drill-or-drop commitment the licence will automatically terminate on the expiry of such period if the licensee fails to (i) take the actions that are described in the first part of the Work Programme and (ii) undertake to complete the second part of the Work Programme by the expiry of the initial term. Unlike the Promote Licence, licensees must demonstrate financial and technical competence from the outset.

(c) The "*West of Shetland Frontier Licence*" was a variation of the Frontier Licence, specifically targeted at blocks located West of Shetland, with an even longer exploration period.

Most recently, the OGA has decided to introduce a new variation of the seaward production licence: the "*Innovate Licence*". From the 29th licensing round (which was launched in July 2016 onwards), all new offshore production licences will be innovate licences, which are intended to offer greater flexibility for licensees to design a Work Programme around particular circumstances. This means that from now on the other variations of the seaward production licence discussed above (the Promote Licence, etc.) will no longer be issued, although this has no impact on licences already in existence. A key feature of the Innovate Licence is that it retains the initial term of previous licence types, but this initial term can be subdivided into up to three phases: Phase A for carrying out geotechnical studies and geophysical data reprocessing; Phase B for undertaking seismic surveys and acquiring other geophysical data; and Phase C for drilling.

2.6 **Model Clauses**

All licences incorporate "model clauses" which set out the terms and conditions under which the licence is granted. The model clauses are laid down in secondary legislation – currently the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008 – and follow a standard format. Up to the 19th licensing round, the model clauses were incorporated into licences by means of a single short paragraph (which specifies which set of model clauses apply to the relevant licence), but from the 20th round onwards they have been set out in full in the licence itself.

The latest model clauses came into effect on 6 April 2008. They apply to all types of licences awarded at the 25th licensing round, and to any subsequent licensing rounds. Any differences necessary to reflect the different types of licence are set out in a schedule to the licence in question. They do not apply to, and have no impact on, any pre-existing licences.

(a) Key obligations under the model clauses

The following provides an overview of the main obligations of the licensee under the current model clauses:

(i) **Term** (model clauses 3 to 11) – production licences have three terms and a licensee can only move on to the next term if it satisfies certain requirements (which can include obligations to surrender parts of the licensed acreage to the OGA). See the summaries above for the differences in term for the different types of licence.

(ii) **Payment** (model clause 12) – licences carry an annual charge (a "rental"). Rentals start at a low rate on each square kilometre covered by the licence at the relevant date and escalate to a maximum rate after several years (typically escalating over a period between 10 and 20 years) to encourage licensees to surrender acreage they do not intend to exploit.

(iii) **Appointment of operators** (model clause 24) – the licensee must get approval for any other party to be operator though the OGA will usually give its consent if that person is competent to exercise the function. Where an approved person is no longer deemed competent such consent may be revoked.

(iv) **Work programme obligations** (model clause 16) – these are the minimum exploration work obligations that a licensee must perform if the licence is not to expire at the end of the initial term. In addition the licensee must comply with any requirement issued by the OGA to submit an appropriate exploration programme. If the OGA is of the opinion that the programme does not satisfy relevant requirements it may query it giving reasons following which the licensee may either submit a further programme or refer the matter to arbitration. The licensee must comply and carry out any approved programme.

(v) **Development and production programmes** (model clauses 17 and 18) – a licensee may not produce or develop any petroleum found without the consent in writing of the OGA or in accordance with an already approved programme (which must specify such works the licensee proposes to carry out to extract such petroleum, including the proposed location of the works and the maximum and minimum quantities proposed to be extracted). Once the OGA has approved a development and/or production programme, the licensee is obliged to carry it out.

(vi) **Commencement, abandonment and plugging of wells** (model clause 19) **-** the OGA's consent must be obtained for the drilling or abandonment of any well and licensees must comply with any conditions imposed by the OGA. Any well that has not been plugged or abandoned must be left in good order and fit for future working.

(vii) **Indemnity against third party claims** (model clause 38) – the licensee is obliged to indemnify the OGA against all actions, proceedings, costs, charges, claims etc. from any third party in relation to the licence or anything done in pursuance of it. The model clauses do not specify how this could be achieved and theoretically this could mean that the licensee may still be obliged to indemnify the OGA after the expiry of the licence, however this has never been tested.

(b) Restrictions on assignment, encumbrances and change of control

Assignment of all or any part of a licence is prohibited without the consent of the OGA. Model clause 40 is drafted widely such that the OGA's consent will be required for assignments between affiliated companies as well as between unrelated companies. Consent will also be required for the withdrawal of a company from a licence where that company is assigning its rights to the remaining licensees under that licence.

As a matter of policy, the OGA looks positively on licence assignments, viewing them as an attempt by the licensees to improve and maximise the opportunities made available to them under the licence.

Similarly to an assignment, the creation of a charge on a licence requires the consent of the OGA. In practice, in most cases prior consent is not required before a charge is created, because an Open Permission applies to any fixed or floating charge or debenture. It is a condition of the Open Permission that the licensee must give notice to the OGA, within ten days of creation of the charge, providing information about the date of the charge, the size of the loan secured by it, the licences affected, and the identity of the charge.

Pursuant to the model clauses (model clause 41 – see section (c) below), a change in control of a licensee can lead to a revocation of the licence (see below). This is on the basis that under the model clauses, if there is a change in control, the OGA can require that a further change in control takes place and if that requirement is not fulfilled within 3 months, the OGA can revoke the licence. There is no provision in the model clauses allowing the licensee to obtain the OGA's prior assurance that this power will not be exercised upon a change in control taking place. However, the OGA acknowledges that this creates a practical difficulty for licensee companies. It has therefore developed a practice whereby parties can apply to the OGA for an assurance that the power to require a further change in control will not be exercised. This assurance operates as a "comfort letter" rather than as a statutory approval.

(c) Breach and revocation of the licence

Model clause 41 sets out the circumstances under which the OGA can revoke a licence. Where a licence is revoked, the licensee will lose its rights under the licence but will remain subject to any obligations or liabilities already incurred under the licence. The OGA can revoke a licence in the following circumstances:

(i) any rental being outstanding two months after it has become due;

(ii) any breach or non-observance of any of the licence terms;

(iii) any bankruptcy, sequestration, arrangements or composition of creditors, appointment of a receiver, administrator or any liquidation whether compulsory or voluntary of the licensee;

(iv) breach of any development scheme (defined as a scheme for the working and development of a field and must be approved by the OGA);

(v) the licensee ceasing to direct and control its operations or commercial activities from the United Kingdom;

(vi) breach of any condition subject to which the OGA gave its approval; or

(vii) in circumstances of change in control of the licensee if the licensee fails to make further changes in control as specified. A change in control for these purposes probably includes lenders with security over the shares in the licensee exercising their enforcement remedies under that security.

Whilst these powers of revocation seem broad, under the regulatory oversight of BEIS (and its predecessors) in general disputes have been settled amicably prior to the regulator exercising these rights. It seems likely that this approach will be followed by the OGA, with revocation being seen as a remedy of last resort, particularly given that the OGA has been given a wider range of sanctions that it can impose on licensees to ensure that the licence terms are complied with.

(d) Bankruptcy and administration and effects on the licence

As noted above any bankruptcy, sequestration arrangements or composition of creditors, appointment of a receiver, administrator or any liquidation whether compulsory or voluntary of the licensee will give the OGA a right to revoke the licence.

3. Decommissioning

3.1 Overview of decommissioning

Decommissioning is the process of dismantling, removing and disposing of petroleum production and transportation infrastructure and eliminating its environmental footprint once a producing field is near or at the end of its economic life. This includes the process of plugging and abandoning wells, pipelines and all other related facilities and consideration of reuse options for platforms and rigs. It has become a key issue in the UKCS where presently there are over 250 fixed oil and gas installations, over 3,000 pipelines and approximately 3,650 wells, all of which in due course must be decommissioned. Whilst decommissioning is in its infancy in the UKCS, over the next ten years 153 projects are forecast to be decommissioned and industry estimated decommissioning expenditure between 2016 and 2025 is estimated to be £17.6 billion.

BEIS' Offshore Decommissioning Unit is the competent authority for decommissioning (formerly DECC's responsibility). In accordance with the principle of MER UK there is a need to significantly reduce decommissioning costs through increased efficiency and industry transformation. The OGA therefore works with BEIS to assess decommissioning programmes on the basis of cost, future use and collaboration.

3.2 **Section 29 Notice**

Decommissioning is primarily governed by part IV of the Petroleum Act which imposes a clear requirement on licensees to pay for offshore installations to be properly decommissioned and completely removed from the seabed other than in exceptional circumstances.

Section 29 of the Petroleum Act gives BEIS power to serve a Section 29 Notice which either specifies a date by which a decommissioning programme for each installation or pipeline is to be submitted or, as is more usual, provides for it to be submitted on or before such date as BEIS may direct. BEIS recommends decommissioning planning occurs at least three years before forecast cessation of production. However with today's typically smaller fields BEIS now tends to require a plan (including security measures and estimated costs) to be in place at the time of approval of a field development plan.

As a result of MER UK, a person on whom a Section 29 Notice is served must consult with the OGA before submitting a decommissioning programme to BEIS and must frame the programme so as to ensure that the cost of carrying it out is kept to a reasonable minimum.

The decommissioning programme will set out and describe in detail the proposed measures to be taken and will include estimated costs, timings, radioactive material handling, environmental impact assessment, removal of debris from the seabed and ongoing monitoring of the area after removal of the installation, while also tying in with related consents procedures under other applicable law. There are a number of possibilities for the items being decommissioned including salvage, waste storage, carbon capture and storage, pipeline reuse and recycling.

Once the decommissioning programme is approved by BEIS the holders of the Section 29 Notice are legally obliged to carry it out on a joint and several liability basis which is then reapportioned in line with their liabilities under the joint operating agreement. If they fail to do so, in theory BEIS could step in to carry out the work and invoice the holders of the Section 29 Notice.

3.3 **Liability of other parties**

In theory BEIS can serve a Section 29 Notice on a wide range of parties; not just the present licensees and operator but also anyone owning an "interest" (undefined) in an installation "other than as security for a loan" and associated companies (broadly 50% direct or indirect affiliates) of companies which are directly liable to have a Section 29 Notice served on them.

BEIS also has the power to withdraw Section 29 Notices (under section 31(5) of the Petroleum Act), for example in respect of ex-licensees who have sold on their interest, usually subject to serving a Section 29 Notice on any incoming licensee and consulting other existing licensees. Crucially however BEIS can also re-issue any notices withdrawn in this way (under section 34 of the Petroleum Act 1998) so the risk of (re)incurring liability for former licensees is never extinguished. Under section 34 of the Petroleum Act 1998, once BEIS has approved a decommissioning programme submitted to it, BEIS is entitled (after making representations) to require a further class of persons to take responsibility for the costs of decommissioning. This further class of persons include, in essence, anyone who could at any time have been served with a Section 29 Notice (although BEIS may not issue a notice to an associated company of a company directly liable to have a Section 29 Notice served on it unless it appears to BEIS that a person already under a duty to secure the decommissioning programme has failed or may fail to discharge that duty). If BEIS considers that making a section 34 notice will have an effect on the cost of carrying out the decommissioning programme, it must consult the OGA and take the effect on the cost into account before deciding whether to issue a notice.

4. HSE issues

4.1 Environmental liability under the licence

The model clauses require all licensees to operate in accordance with the methods customarily used in good oilfield practice and to take all steps practicable (a very wide concept) in order to prevent the escape or waste of petroleum and to prevent the escape of petroleum into any waters in or in the vicinity of the licensed area. As well as being required to comply with all applicable laws, licensees are also expected to have sufficient funds available to discharge any liability for damage in connection with the release or escape of petroleum. They must also keep the OGA indemnified against any and all claims brought against OGA by any third party in relation to or in connection with the licence.

The model clauses do not distinguish between the operators and non-operators in relation to the liability of each: all licensees under the licence will be jointly and severally liable for any breach of its terms.

4.2 Environmental regulations

There is a detailed and complex environmental regime applying to oil and gas activities in the UKCS, comprising a large number of statutory instruments. These include, but are not limited to, the Merchant Shipping (Oil Pollution Preparedness, Response & Cooperation Convention) Regulations 2015, and the Offshore Installations (Emergency Pollution Control) Regulations 2002 (together the **OPEP Regulations**). The OPEP Regulations are the main regulations under which the Government regulates potential environmental incidents involving offshore installations. They are designed to ensure that preventative measures are in place to limit pollution and impose obligations upon operators to implement robust emergency planning arrangements. Powers are reserved for the Government to step in and take measures to enforce any necessary remedial actions.

The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 supplement the OPEP Regulations by imposing a permitting system for release and discharge of oil from an offshore installation (including pipelines), and powers of remediation of pollution in the event of an unauthorised discharge and to recover costs if it has to intervene should the operator fail to do so.

UK inland and coastal clean-up could also involve emergency works under the Water Resources Act, and remediation under the Environmental Damage (Prevention and Remediation) Regulations 2009, and the Environmental Protection Act 1990.

The Gulf of Mexico incident of 20 April 2010 (the "Deepwater Horizon" oil spill) led the European Commission to carry out a review of offshore oil and gas regulatory regimes, resulting in the OSD. The OSD has been transposed into UK law by:

- the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015;
- the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015; and
- the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015,

(together the **OSD Regulations**).

Under the OSD regime, a single appointed installation operator must be responsible for both environmental compliance on offshore platforms and safety management. Operators are appointed by licensee(s).

The OSD Regulations introduce new legal duties for the appointed installation operator (referred to as the "duty holder" for production installations), which include but are not limited to the preparation and submission of a Corporate Major Accident Prevention Plan, a Safety and Environmental Management System and Safety Cases.

The OSD Regulations also confirm that licensees are financially liable for the prevention and remediation of environmental damage. Licensees' obligations under the OSD Regulations include:

- ensuring that any operator appointed by the licensee is capable of satisfactorily carrying out the functions and discharging the duties of the operator under the relevant statutory provisions;

- taking all reasonable steps to ensure that any operator appointed by or in respect of the licensee carries out the functions and discharges the duties of the operator under the relevant statutory provisions; and
- making adequate provision to cover liabilities from offshore operations and maintain sufficient capacity to meet all financial obligations which may result from offshore operations.

4.3 Health and safety

A stringent and well established health and safety regime applies to the UK upstream sector, overseen and enforced by the HSE and OSDR. A key aspect of this is the safety case regime set out under the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015 (referred to above), which applies to the UKCS, and other associated legislation.

The HSE Energy Division/OSDR employ a team of inspectors who are responsible for enforcing both the offshore specific regulations (notably, in addition to the main safety case regulations referred to above, the Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995) and general safety legislation common to all industries, including the overarching Health and Safety at Work etc. Act 1974.

5. Impact Of Brexit

On 23 June 2016, the UK held a referendum to decide whether the UK should remain a member of the European Union (EU). The outcome of that referendum is that the UK has decided to terminate its membership of the EU (referred to as Brexit). On 29 March 2017 the UK Government served notice under Article 50 of the Treaty on European Union of the UK's intention to withdraw from the EU, formally commencing the process by which the UK will leave the EU. The UK's withdrawal from the EU will occur on 29 March 2019 (which will be two years from the date on which the UK served notice), unless otherwise agreed. The notice was followed by a UK Government White Paper, outlining proposals for a "Great Repeal Bill" (subsequently published in July 2017, under its formal title of the European Union (Withdrawal) Bill) which will have the effect of removing the supremacy of EU law over UK domestic law following the UK's withdrawal from the EU (the "Great Repeal Bill White Paper"). For domestic UK affairs, the Great Repeal Bill White Paper deals with the fact that the removal of EU law from UK law on the day of Brexit would leave large gaps in UK law. It is therefore proposed that existing EU law will be removed but then reintroduced as domestic UK law (subject to adaptations as required).

It seems likely that the Great Repeal Bill will not have a significant impact on the fundamental structure of the UK upstream oil and gas industry and its governing legal regime, including the licensing system. Leaving aside the prospect of a possible referendum on Scottish independence (see below), it should be noted that the regulatory framework applying to the upstream industry, and in particular environmental and health and safety regulation, is highly developed independently of EU law, and, at this stage, the industry view is that any impact is likely to be minor. The offshore decommissioning regime mainly stems from international conventions and domestic legislation, and it is therefore expected to be largely unaffected. However, some changes to domestic legislation which implements EU requirements, particularly legislation which refers to EU institutions or processes, are inevitable.

The biggest potential impact of Brexit on the UK upstream oil and gas industry is an indirect one: if Scotland decides to hold a second referendum on independence, which results in Scotland becoming independent from the rest of the UK. Recent news reports indicate that public support in Scotland for independence has fallen. Therefore, on balance, it seems more likely that a referendum will not take place in the short-term.

If a referendum is held and ultimately Scotland does decide to proceed with full independence, then this would have a significant impact on the UKCS oil and gas industry because much of UKCS oil and gas reserves lie in Scottish waters. It has been estimated that if Scotland's maritime boundary was established using the "median line principle" then around 90% of UKCS oil and gas resources would fall under Scottish jurisdiction. Presumably any new regulatory regime put in place by a new independent Scottish Government would include transitional arrangements to appropriately deal with the transfer of existing licences to the new regime.

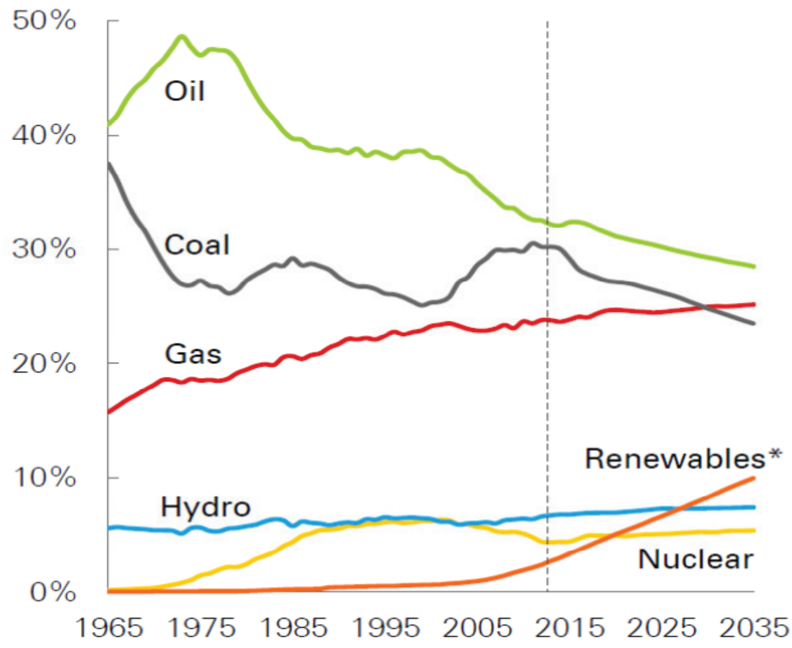
6. The Oil and Gas Market: Trends and Outlook

6.1 Global outlook for fossil fuels

According to BP Energy Outlook, 2017 Edition, the gradual transition in the global fuel mix is set to continue with renewables, together with nuclear and hydroelectric power, expected to account for half of the growth in energy supplies over the next 20 years. Nonetheless, it is predicted by BP Energy Outlook that:

- oil, gas and coal will remain the dominant sources of energy powering the world economy, accounting for more than three-quarters of total energy supplies in 2035 (down from 85% in 2015);
- out of these, gas is the fastest growing fuel (1.6% per annum), with its share in primary energy increasing as it overtakes coal to be the second-largest fuel source by 2035;
- oil continues to grow (0.7% per annum), although its pace of growth is expected to slow gradually.

Shares of primary energy



Source: BP Energy Outlook, 2017 Edition

6.2 Recent trends in the oil and gas market

(a) Crude oil

After a period of high oil prices, crude oil prices fell sharply in the fourth quarter of 2014 as robust global production exceeded demand. After reaching monthly peaks of US$112/bbl and US$105/bbl in June 2014, crude oil benchmarks Brent and WTI fell to US$62/bbl and US$59/bbl in December 2014, respectively. In January 2016 the price of oil briefly fell below US$28 to its lowest point for 13 years but since then there has been some recovery in the price.

North Sea Brent crude oil spot prices averaged US$52/bbl in August 2017. The EIA forecasts Brent spot prices to average US$51/bbl in 2017 and US$52/bbl in 2018. WTI average crude oil prices are forecast to be about US$2/bbl lower than Brent prices in both 2017 and 2018. NYMEX contract values for December 2017 delivery that traded during the five-day period ending 7 September 2017 suggest that a range of US$39/bbl to US$63/bbl encompasses the market expectation for December WTI prices at the 95% confidence level.

(b) Natural gas

According to the International Energy Agency, in 2016 natural gas import prices by pipeline fell by 28.2% for European Union members, while in the United States they fell by 23.0% As such, the gap between these two prices continued closing in 2016, showing a stronger convergence than in the previous year. However, the price for the American market remained much lower than the European one, at US$2.14/MBtu versus US$4.93/ MBtu.

LNG import prices showed a similar pattern, with a general decrease observed in all regions, notably in the US (- 44.7%). After converging in 2014, LNG prices in Europe and the US remained in line in 2016 again whilst in Japan and Korea the gap between their LNG import prices and those for the US and Europe continued to narrow. This convergence is partially driven by the increase in global liquefaction capacity, especially in Australia.

According to the EIA, in August 2017, the average Henry Hub natural gas spot price was US$2.90/MBtu, down 8 cents/MBtu from the July level. Expected growth in natural gas exports and domestic natural gas consumption in 2018 contribute to the forecast Henry Hub natural gas spot price rising from an annual average of US$3.05/MBtu in 2017 to US$3.29/MBtu in 2018. NYMEX contract values for December 2017 delivery that traded during the five-day period ending 7 September 2017 suggest that a range of US$2.39/MBtu to US$4.34/MBtu encompasses the market expectation for December Henry Hub natural gas prices at the 95% confidence level.

6.3 **UK crude oil and natural gas market**

Production of crude oil and natural gas liquids from the UK's North Sea increased by 4.8% in 2016, in contrast with the long-term decline. Production is around a third of the UK's peak of 1999. Petroleum forms a key part of the UK's energy mix. Around 40% of the UK's total energy production is from crude oils extracted from the UKCS, and UK refineries produce around 60 million tonnes of oil products – the 4th largest in Europe. The UK is a significant exporter of crude oils as well as an importer. Crude oil exports increased in 2016 to reach over 30 million tonnes. Crude oil has historically been principally exported to the Netherlands, Germany, France and the US. Exports to the Netherlands recovered in 2016 to comprise 40% of total crude exports after falling to just 31% the previous year. In 2016 exports to France decreased by nearly 1 million tonnes and exports to China increased by 3.3 million tonnes, making China the third largest recipient of UK crude exports after the Netherlands and Germany in 2016.

UK natural gas production in 2016 was up 2.4% on 2015 to 463 terawatt hours, continuing the year-on-year increases seen since 2014. This pattern contrasts with the long-term decline in UK natural gas production, which had fallen by an average of 8% from peak production in 2000 to the end of 2013. Gas production is just over a third of the peak level recorded in 2000. The UK, along with the Netherlands, is one of the two major gas producing nations within the EU. While the UK is a net importer of gas, it also exports gas to the mainland Europe, through gas interconnectors.

According to Oil & Gas UK's Economic Report 2017, the National Balancing Point day-ahead gas price has averaged 43.3 p/th over the first half of 2017, 40% higher than the 30.89 p/th in the first half of 2016. This is largely due to a sharp price increase over the second half of 2016 and into the early part of 2017. Although the role of gas as a heating fuel means it is common for prices to be higher over winter months when demand is higher, the impact was heightened over the winter of 2016/17 due to a shortage of gas storage and uncertainty over LNG supply to the UK. The price has fallen quite rapidly since, reaching a daily low of 25 p/th in June 2017, almost 60% below the daily high of 60.8 p/th at the start of February 2017, and shows little sign of structural recovery in a market defined by a large global oversupply.

PART XI – SUMMARY OF KEY LICENCES AND AGREEMENTS

1. BKR Assets

A summary of the key licences and material contracts relating to the BKR Assets are set out below.

1.1 Bruce Field

Licence P.209

P.209 was granted on 10 July 1972 by the Secretary of State for Trade and Industry to Hamilton Brothers Oil Company (Great Britain) Limited, Hamilton Brothers Petroleum (U.K.) Limited, The Rio Tinto-Zinc Corporation Limited, Blackfriars Oil Company Limited and The Trans-European Company Limited.

P.209 permits the Licensee to search and bore for and get petroleum in Block(s) No. 9/8, 9/28 9/29, 210/14 and 15/24.

P.209 was granted pursuant to the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas, similar to those summarised above in paragraph 2.6(a) of Part X (*Further Information on The Offshore Oil and Gas Industry in the UK*). P.209 incorporates clause 1 and clauses 4 to 34 of the model clauses for production licences in seaward areas set out in Schedule 4 to the Petroleum (Production) Regulations 1966 (S.I. 1966/898) as amended by the Petroleum (Production) (Amendment) Regulations 1971 (S.I. 1971/814).

The initial term of P.209 was six years from 16 March 1972. It was extended by a further forty years and the second term is due to expire on 15 March 2018. The original work obligations are to, within the six year initial term, carry out seismic survey work and drill three exploration wells, with a possible fourth well subject to the Secretary of State's satisfaction.

Under the terms of P.209, on the tenth, and every subsequent, anniversary of the date specified in the notice, the Licensee shall pay to the Secretary of State the total of £350 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

Licence P.276

P.276 was granted on 16 June 1978 by the Secretary of State for Energy to The British National Oil Corporation (now part of BP) and BP Petroleum Development Limited.

P.276 permits the Licensee to search and bore for and get petroleum in Block(s) No. 9/9b and 9/15b.

P.276 was granted pursuant to the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas, similar to those summarised above in paragraph 2.6(a) of Part X (*Further Information on the Offshore Oil and Gas Industry in the UK*). P.276 incorporates clause 1 and clauses 4 to 41 of the model clauses for production licences in seaward areas set out in Schedule 5 to the Petroleum (Production) Regulations 1976 (S.I. 1976/1129).

The term of P.276 has been extended to such permanent cessation of production in the Bruce field as is agreed by the OGA in due course. The work obligations are to drill one exploration well within the initial term and drill a further two exploration wells, with one being optional subject to the Minister's satisfaction that a second well is not justifiable. Under the terms of P.276, on the fourteenth, and every subsequent, anniversary of the date specified in the notice, the Licensee shall pay to the Secretary of State the total of £3000 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

Unit and Unitisation Operating Agreement

BP is party to a Unit and Unitisation Operating Agreement (the "**Bruce UUOA**") as amended and novated from time to time in respect of the Bruce field. The Bruce UUOA outlines the processes and procedures for recovering hydrocarbons from the Bruce field.

The Bruce UUOA contains largely standard provisions on many key areas, as would be expected in a UKCS UUOA, including terms in respect of confidentiality, assignment and default. The UUOA outlines the voting requirements for making decisions in the management committee, with different passmarks required for varying decisions, what encumbrances can be placed on a party's unit equity, procedures for decommissioning and abandonment, and specifies the procedure for the removal and resignation of an operator.

Joint Operating Agreement in respect of Licence P.209

BP is party to a joint operating agreement in respect of Licence P.209 (the "**P.209 JOA**") which has been superseded by the Bruce UUOA in respect of that area of Block 9/8a (Bruce) and Block 9/8a (Rest) which lie within the Bruce field.

The P.209 JOA contains largely standard provisions on many key areas, as would typically be seen in a UKCS joint operating agreement.

The P.209 JOA outlines the voting requirements for making decisions in the management committee, with different passmarks required for varying decisions, withdrawal and default procedures, what encumbrances can be placed on a party's interest in the P.209 JOA, procedures for decommissioning and abandonment, and specifies the procedure for the removal and resignation of an operator.

Joint Operating Agreement in respect of Licence P.276

BP is party to a joint operating agreement in respect of Licence P.276 ("**P.276 JOA**") which has been superseded by the Bruce UUOA in respect of that area of Block 9/9b (Bruce) which lies within the Bruce field.

The P.276 JOA contains largely standard provisions on many key areas, as would typically be seen in a UKCS joint operating agreement.

The P.276 JOA outlines the voting requirements for making decisions in the management committee, withdrawal and default procedures, what encumbrances can be placed on a party's interest in the P.209 JOA, procedures for decommissioning and abandonment, and specifies the procedure for the removal and resignation of an operator.

1.2 **Keith Field**

Licence P.209

P.209 is as summarised above at paragraph 1.1 of this Part XI (*Summary of Key Licences and Agreements*).

Joint Operating Agreement in respect of Licence P.209

BP is party to a joint operating agreement in respect of Licence P.209 ("**P.209 JOA**").

The P.209 JOA contains largely standard provisions on many key areas, as would typically be seen in a UKCS joint operating agreement.

The P.209 JOA outlines the voting requirements for making decisions in the management committee, with different passmarks required for varying decisions, withdrawal and default procedures, what encumbrances can be placed on a party's interest in the P.209 JOA, procedures for decommissioning and abandonment, and specifies the procedure for the removal and resignation of an operator.

1.3 **Rhum Field**

Licence P.198

P.198 was granted on 10 July 1972 by the Secretary of State for Trade and Industry to BP Petroleum Development Limited and Iranian Oil Company (U.K.) Limited.

P.198 permits the Licensee to search and bore for and get petroleum in Block(s) No. 3/29 and 15/13.

P.198 was granted pursuant to the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas, similar to those summarised above in paragraph 2.6(a) of Part X (*Further Information on the Offshore Oil and Gas Industry in the UK*). P.198 incorporates clause 1 and clauses 4 to 34 of the model clauses for production licences in seaward areas set out in Schedule 4 to the Petroleum (Production) Regulations 1966 (S.I. 1966/898) as amended by the Petroleum (Production) (Amendment) Regulations 1971 (S.I. 1971/814).

The initial term of P.198 was originally six years from 16 March 1972. It was extended by a further forty years and the second term is due to expire on 15 March 2018. The original work obligations are to, within the term of the Licence, carry out seismic survey work and drill three exploration wells.

Under the terms of P.198, on the tenth, and every subsequent, anniversary of the date specified in the notice, the Licensee shall pay to the Secretary of State the total of £350 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

Joint Operating Agreement in respect of Licence P.198

BP is party to a joint operating agreement in respect of Licence P.198 ("**P.198 JOA**").

The P.198 JOA contains largely standard provisions on many key areas, as would typically be seen in a UKCS joint operating agreement, but does not include provisions in respect of default or decommissioning.

The other parties to the P.198 JOA have a right of pre-emption in respect of any assignment of an interest by a party to a third party. The P.198 JOA outlines the voting requirements for making decisions in the operating committee, withdrawal procedures, what encumbrances can be placed on a party's interest in the P.198 JOA, and specifies the procedure for the removal and resignation of an operator.

1.4 **Additional Areas**

The additional areas fall into two groups (a) the Bruce non-unitised areas and (b) the Rhum non-unitised areas. These areas do not form part of unit operations and are not currently producing any reserves. They are outlying areas to the main fields.

(a) **Bruce non-unitised areas**

Licences P.209 and P.276 are as summarised above at paragraph 1.1 of this Part XI (*Summary of Key Licences and Agreements*).

Licence P.090

P.090 was granted on 11 January 1966 by the Minister of Power to Total Oil Marine Limited, Coastal Oil Company Limited, Auxtrap (U.K.) Limited, Eurafrep Oil Company Limited, Cofrasea Oil Company Limited and Coparex North Sea Petroleum Company Limited.

P.090 permits the Licensee to search and bore for and get petroleum in Block(s) No. 3/9, 3/10, 3/14, 3/15, 3/24, 3/25, 9/9, 9/10, 9/14 and 9/15.

P.090 was granted pursuant to the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas, similar to those summarised above in paragraph 2.6(a) of Part X (*Further Information on the Offshore Oil and Gas Industry in the UK*). P.090 incorporates clause 1 and clauses 4 to 33 of the model clauses for production licences set out in Schedule 2 to the Petroleum (Production) (Continental Shelf an Territorial Sea) Regulations 1964 (S.I. 1964/708).

The term of P.090 was extended by forty years to 24 November 2011. The term was then extended by another forty years until 24 November 2051. The original work obligations are to, within the term of the Licence, carry out seismic survey work and drill one exploration well.

Under the terms of P.090, on the tenth, and every subsequent, anniversary of the date specified in the notice, the Licensee shall pay to the Minister the total of £290 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

(b) **Rhum non-unitised areas**

Licence P.566

P.566 was granted on 7 September 1987 by the Secretary of State for Energy to Shell U.K. Limited and Esso Exploration and Production UK Limited.

P.566 permits the Licensee to search and bore for and get petroleum in Block No. 3/29b.

P.566 was granted pursuant to the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas, similar to those summarised above in paragraph 2.6(a) of Part X (*Further Information on the Offshore Oil and*

Gas Industry in the UK). P.566 incorporates clause 1 and clauses 4 to 40 of the model clauses for production licences in seaward areas set out in Schedule 5 to the Petroleum (Production) Regulations 1982 (S.I. 1982/1000).

The term of P.566 is due to expire on 3 June 2023 and the working obligations are to, before the end of the initial term, carry out not less than 300 kilometres of seismic survey work and drill one exploration well to a depth of not less than 17,000 feet.

Under the terms of P.566, on the fourteenth, and every subsequent, anniversary of the date specified in the notice, the Licensee shall pay to the Secretary of State the total of £6,000 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

Licence P.975

P.975 was granted on 20 June 2000 by the Secretary of State for Trade and Industry to BP Exploration Operating Company as sole licensee.

P.975 permits the Licensee to search and bore for and get petroleum in Block(s) No. 3/24b and 3/29d.

P.975 was granted pursuant to the Petroleum Act 1998 and contains largely standard provisions on many key areas, similar to those summarised above in paragraph 2.6(a) of Part X (*Further Information on the Offshore Oil and Gas Industry in the UK*). P.975 incorporates clause 1 and 4 to 43 of the model clauses for production licences in seaward areas set out in Schedule 4 to the Petroleum (Production) (Seaward Areas) Regulations 1988 (S.I. 1988/1213), as amended.

The term of P.975 is due to expire on 22 December 2034 and the working obligations are to purchase 96 square kilometres of speculative 3D seismic over 3/24b within one year of commencement of the Licence, or such longer period as the Minister may agree.

P.975 contains additional restrictions and conditions with regard to environmental/seismic and drilling activities, as well as oil spills, due to the presence at certain times of year of concentrations of seabirds, seabird colonies, marine habitats and communities, cetaceans/sea mammals.

Under the terms of P.975, on the fourteenth, and every subsequent, anniversary of the date specified in the notice, the Licensee shall pay to the Secretary of State the total of £7050 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

2. Serica Assets

A summary of the key licences and material contracts relating to the Serica assets are set out below.

2.1 Erskine

P.057 Licence

The Erskine P.057 licence was granted on 31 December 1965 between the Minister of Power and BP Petroleum Development Limited (the "**P.057 Licensee**") (the "**P.057 Licence**"). Serica UK acquired its interest in the P.057 Licence pursuant to an assignment from BP Exploration Operating Company Limited.

The P.057 Licence was granted by the Minister of Power under the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas.

The P.057 Licence grants the P.057 Licensee permission to search and bore for petroleum in the sea bed and subsoil under the search area compromising Block 23/26a. The term of the P.057 Licence is determined pursuant to clause 3 of the model clauses set out in Schedule 2 of the Petroleum (Production) (Continental Shelf and Territorial Sea) Regulations 1964 (S.I. 1964 no. 708).

The P.057 Licensee is obliged to, during the term of the P.057 Licence, carry out seismic survey work in the licensed area and drill therein two exploration wells.

Under the terms of the P.057 Licence, on the tenth, and every subsequent, anniversary of the date specified in the notice, the P.057 Licensee shall pay to the Minister of Power the total of £290 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

P.264 Licence

The Erskine P.264 Licence was granted on 20 December 1977 between the Secretary of State for Energy (the "**SoS for Energy**"), the British National Oil Corporation and Texaco North Sea UK Limited (the "**P.264 Licensee**") (the "**P.264 Licence**", and together with the P.057 Licence, the "**Erskine Licences**"). Serica UK acquired its interest in the P.264 Licence pursuant to an assignment from BP Exploration Operating Company Limited.

The P.264 Licence was granted under the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964 and contains largely standard provisions on many key areas.

The P.264 Licence grants the Licensee permission to search and bore for petroleum in the sea bed and subsoil under the search area compromising Block 23/26b. The term of the P.264 Licence is determined pursuant to clause 3 of the model clauses set out in Sch 5 of the Petroleum (Production) Regulations 1976 (S.I. 1976 no. 1129).

Under the terms of the P.057 Licence, on the fourteenth, and every subsequent, anniversary of the date specified in the notice to continue the P.264 Licence for the third term, the Licensee shall pay to the SoS for Energy the total of £3000 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

Utilisation and Unit Operating Agreement

Serica UK is party to the Erskine Unitisation and Unit Operating Agreement (the "**Erskine UUOA**"), dated 27 April 1995, as amended and novated from time to time, in connection with the Erskine Licences. The Erskine UUOA contains largely standard provisions on many key areas, including in relation to confidentiality, default and withdrawal.

The Erskine UUOA provides for the unitisation, exploration and development of the hydrocarbon accumulation extending over Blocks 23/26a and 23/26b.

The parties to the Erskine UUOA each have a representative on the unit operating committee who will have a vote equal to the party's interest for any decision being voted, such votes needing to reach a 70% threshold in order to pass.

Parties to the Erskine UUOA may only transfer their interests in the Erskine Licences to an (i) affiliate which has the financial capability to meet its obligations or (ii) to another party to the Erskine UUOA or other third party which has the financial capability to meet its obligations. The parties to the Erskine UUOA have certain pre-emption rights in relation to a transfer under (ii) above.

Erskine Sale and Purchase Agreement

The Company acquired its interest in the Erskine Licences field pursuant to a sale and purchase agreement dated 16 June 2014 between the Company, Serica UK, BP and Britoil Limited ("**Britoil**") (the "**Erskine SPA**"). The transaction completed on 4 June 2015. Serica UK, as well as the Company, which guarantees Serica UK's payment and other obligations under the Erskine SPA, has certain outstanding payment obligations, and could be liable pursuant to certain obligations under the Erskine SPA, as set out below.

Part of the consideration payable by Serica UK under the Erskine SPA is contingent consideration, payable by Serica UK in the event that operating costs for the field fall below projections at the time of the Erskine SPA. The contingent consideration is calculated by reference to the gross cumulative share of operating expenditure incurred by the parties to the Erskine UUOA in respect of the Lomond field.

Under the Erskine SPA, Serica UK provides a clean break indemnity in favour of Britoil and BP in respect of environmental and other liabilities with effect from 1 January 2014.

2.2 Columbus

P.1314 Licence

The Seaward Production Licence (the "**P.1314 Licence**") was granted by a deed of licence dated 7 March 2006 between the Secretary of State for Trade and Industry (the "**SoS for Trade and Industry**"), Endeavour Energy UK Limited and Serica UK. This P.1314 Licence was later amended, pursuant to which EOG Resources United Kingdom Limited became a party to the P.1314 Licence on 21 February 2007.

The P.1314 Licence was granted under the Petroleum Act.

The P.1314 Licence grants Endeavour Energy UK Limited, EOG Resources United Kingdom Limited and Serica UK (together the "**Columbus Licensee**") exclusive licence to search for petroleum in the sea bed and subsoil under the seaward area compromising Block(s) 23/16f outlined on the reference map found at the principal office of the Department of Trade and Industry.

The initial term of the P.1314 Licence, which began on 22 December 2005, was for four years. The P.1314 Licence contains the opportunity for continuation for a further four years after expiry of the initial term after which the term could be extended again for a further 18 years. After the expiry of this period, the SoS for Trade and Industry and the Licensee can agree a further extension.

Under the terms of the P.1314 Licence, on the twelfth anniversary of the commencement date of 22 December 2005 and every year thereafter, the Columbus Licensee shall pay the SoS for Trade and Industry £7500 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

These payments may increase or decrease in line with movements in the Index of the Price of Crude Oil acquired by Refineries, or comparable index if the former ceases to be published, if the SoS for Trade and Industry so determines. Where the P.1314 Licence is determined, or a licensed area has been surrendered, the Licensee shall not be entitled to be repaid or allowed any sum payable to the SoS for Trade and Industry before the date of determination or surrender.

P.101 Licence

The P.101 Licence was granted on 29 July 1970 between the Minister of Technology and The Gas Council, Amerada Exploration Limited, Texas Eastern (U.K.) Limited and Amoco (U.K.) Petroleum Limited. Through various assignments, the current licensees are Endeavour Energy UK Limited, EOG Resources United Kingdom Limited and Serica UK (the "**P.101 Licensees**") (the "**P.101 Licence**" and together with the P.1314 Licence, the "**Columbus Licence**").

The P.101 Licence was granted under the Petroleum (Production) Act 1934 and the Continental Shelf Act 1964.

The P.101 Licence grants the P.101 Licensees the right to search and bore for and get petroleum in Blocks 23/21a.

The term of the P.101 Licence is determined pursuant to clause 3 of the model clauses set out in Schedule 2 of the Petroleum (Production) Regulations 1966 (S.I. 1966 no. 708).

The P.101 Licensees are obliged to, during the term of the P.101 Licence, carry out seismic survey work in the licensed area and drill therein at least three exploration wells.

Under the terms of the P.101 Licence, on the tenth, and every subsequent, anniversary of the date specified in the notice, the P.101 Licensees shall pay to the Minister of Power the total of £350 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

Joint Operating Agreement

Serica UK is party to a joint operating agreement dated 27 September 2006 in connection with the Columbus Licence with EOG Resources United Kingdom Limited and Endeavour Energy UK Limited (the "**Columbus JOA**") as amended and novated from time to time. The Columbus JOA contains largely standard provisions on many key areas, including in relation to confidentiality, assignment, sole risk, default and withdrawal.

The Columbus JOA provides for the establishment of an operating committee for the purposes of overall supervision and control. Each party holding a participating interest is entitled to appoint one representative and one alternate to serve on the operating committee.

Except as provided, decisions of the operating committee require the affirmative vote of two or more parties that are not affiliates, holding collectively at least 65% of the participating interests. Serica UK is designated to act as the operator under the Columbus JOA.

2.3 **Rowallan**

Seaward Production Licence

The Seaward Production Licence (the "**Rowallan Licence**") was granted by a deed of licence by the Secretary of State for Energy and Climate Change (the "**SoS for Climate Change**") to Serica UK (the "**Rowallan Licensee**") on 9 July 2009.

The Rowallan Licence was granted under the Petroleum Act.

The Rowallan Licence grants the Rowallan Licensee the exclusive licence to search for petroleum in the sea bed and subsoil under the seaward area compromising Block 22/19c.

The initial term of the Rowallan Licence, was for four years from 20 June 2009. The Rowallan Licence contains an option to extend the term for a further four years, after which the term could be extended again for a further 18 years. It has already been agreed that the initial further extension will be for six years until 19 June 2018, meaning a further extension of 16 years is possible after the expiry of this term. After the expiry of this total period, the SoS for Climate Change and Licensee can agree a further extension.

Under the terms of the Rowallan Licence, on the ninth, and every subsequent, anniversary of the commencement date of 20 June 2009, the Rowallan Licensee shall pay to the SoS for Climate Change the total of £7500 multiplied by the number of square kilometres comprised in the licensed area when the payment becomes due.

These payments may increase or decrease in line with movements in the Index of the Price of Crude Oil acquired by Refineries, or comparable index if the former ceases to be published, if the SoS for Climate Change so determines.

Joint Operating Agreement

Serica UK entered into a joint operating agreement with JX Nippon Exploration and Production (U.K.) Limited ("**JX Nippon**") dated 22 October 2012 (the "**Rowallan JOA**") as amended and novated from time to time. The Rowallan JOA sets out the rights of the parties to it in connection with the Rowallan Licence. The Rowallan JOA contains largely standard provisions on many key areas, including in relation to confidentiality, assignment, sole risk, default and withdrawal.

The Rowallan JOA provides for the establishment of an operating committee for the purposes of overall supervision and control. Each party holding a participating interest is entitled to appoint one representative and one alternate to serve on the operating committee.

Except as provided, decisions of the operating committee require the affirmative vote of two or more parties that are not affiliates, holding collectively at least 71% of the participating interests. Certain decisions will require a unanimous vote. JX Nippon was designated to act as the operator under the Rowallan JOA. This role has now passed to ENI UK Limited pursuant to certain novation agreements.

Farm-In Agreement

Serica UK entered into a farm-in agreement for Licence 1620, block 22/19c (the "**Farm-In Agreement**") dated 17 September 2012 with JX Nippon.

The purpose of the Farm-In Agreement was for Serica UK to transfer an undivided legal interest in the Rowallan Licence as well as an 85% undivided legal and beneficial interest in and under the 22/19c JOA, in return for JX Nippon undertaking to drill or procure the drilling of a well meeting certain depth obligations. The well is intended to be on the Rowallan prospect. JX Nippon has the right to re-assign its interest to Serica UK for nominal consideration, which right expires upon the joint operating committee's approval of the well programme for the exploration well under the Rowallan JOA.

2.4 **Slyne**

Licence

The Petroleum Exploration Licence 1/06 (Frontier) (the "**Slyne Licence**") was granted by a deed of licence dated 16 February 2007 between the Minister for Communications, Marine and Natural Resources and Serica UK.

DEA Deutsche Erdoel AG ("**DEA**") and Serica Slyne became parties to the licence through the executions of the addendums dated 7 May 2009 and 18 October 2012 respectively. Through various assignments of interest 100% of the interest in the Slyne Licence is now vested in Serica Energy Slyne B.V (the "**Licensee**").

The Slyne Licence was granted under Section 8 of the Petroleum and Other Minerals Development 1960.

The Slyne Licence is valid from 1 December 2006 to 30 November 2023 unless surrendered or revoked and is divided into four phases. The Slyne Licence is currently in its third phase which began on 1 December 2011 and ends on 30 November 2018.

The licensed area comprises Blocks 27/4, 27/9 and part Block 27/5 and the Slyne Licence grants the Licensee exclusive licence to search for petroleum in the licensed area so long as the Slyne Licence is valid.

Payments of €80,000 and €16,000 are payable each year and are subject to adjustments in line with the Consumer Price Index. The Slyne Licence contains an option for the base levels of these contributions to be adjusted after five years by the Minister for Communications, Marine and Natural Resources following consultation with the Licensee.

2.5 **Rockall**

1/09 Licence

The Petroleum Exploration Licence 1/09 (Frontier) (the "**1/09 Licence**") was granted by a deed of licence dated 24 July 2009 between the Minister for Communications, Marine and Natural Resources and Serica UK. Pursuant to an addendum dated 18 October 2012, Serica UK assigned 100% of its interest in the 1/09 Licence to Serica Energy Rockall B.V. (the "**Licensee**").

The 1/09 Licence is valid from 21 July 2009 to 20 July 2027 unless surrendered or revoked and is divided into four phases. The first phase of the 1/09 Licence expired on 20 July 2017. Confirmation has been received from the Department of Communications, Climate Action & Environment in Ireland that the Minister of State has given his consent to extend the first phase of the licence to 20 January 2019, but as at the date of this document, the extension has not be formalised.

The licensed area comprises Blocks 5/17 (part), 5/18, 5/22 (part), 5/23 (part), 5/27 (part) and 5/28 (part), and the 1/09 Licence grants the Licensee exclusive licence to search for petroleum in the licensed area so long as the 1/09 Licence is valid.

Payments of €87,361 and €17,472 are payable each year and are subject to adjustments in line with the Consumer Price Index. The 1/09 Licence contains an option for the base levels of these contributions to be adjusted after five years by the Minister following consultation with the Licensee.

If a second exploration well has not been commenced by 21 July 2021, or an extension not granted, Licence 1/09 must be surrendered on that date.

4/13 Licence

The Petroleum Exploration Licence 4/13 (Frontier) (the "**4/13 Licence**") was granted by a deed of licence by the Minister for Communications, Marine and Natural Resources to Serica Rockall on 14 January 2014.

The licensed area comprises Blocks 11/10, 11/15, 12/1(part), 12/6 and 12/11(part), and the 4/13 Licence grants Serica Rockall exclusive licence to search for petroleum in the licensed area so long as the 4/13 Licence is valid.

The 4/13 Licence is divided into four phases and is currently in its first phase which began on 1 December 2013 and ends on 30 November 2018. The first phase was extended in a deed of amendment dated 21 June 2017 which also extended the remaining phases to 30 November 2030 unless surrendered or revoked.

2.6 Namibia

Licence

The Petroleum Agreement (the "**Namibia Agreement**") dated 11 December 2011 was entered into between the Minister of the Ministry of Mines and Energy, National Petroleum Corporation of Namibia (PTY) Ltd ("**NAMCOR**"), Serica Namibia and Indigenous Energy (PTY) Ltd ("**IEPL**").

The Namibia Agreement states that an exploration licence was issued in accordance with the provisions of section 34 of the Petroleum (Exploration and Production) Act 1991 to NAMCOR, Serica Namibia and IEPL upon delivery by Serica Namibia and IEPL of the performance guarantees to the government and delivery by the company of the bank guarantee. The Namibia Agreement also provides for a production licence to be issued in the event that a discovery is made and a petroleum field is declared.

The Namibia Agreement relates to the licence area comprising Blocks 2512A, 2513A, 2513B and 2612A (part) in the Luderitz Basin.

Subject to the provisions of the Petroleum (Exploration and Production) Act 1991, the exploration licence (the "**Namibia Licence**") granted to the Company was for an initial term of four years from the date the Namibia Agreement**.** Subject to the provisions of the Petroleum (Exploration and Production) Act 1991, the Namibia Licence may be renewed up to a further two occasions, with each renewal not to exceed two years.

Subject to the Petroleum (Exploration and Production) Act 1991, the Commissioner for Petroleum Affairs may order the relinquishing of:

(a) at least 50% of the exploration area not later than 30 days before the end of the fourth year of the Namibia Licence; and

(b) at least a further 25% of the exploration area not later than 30 days before the end of the Namibia Licence.

A quarterly royalty payment of 5% of the market value of both the crude oil and natural gas which has been determined by agreement is payable.

In the case of the Namibia Licence an annual fee is payable calculated by multiplying the number of square kilometres included in the blocks to which the Namibia Licence relates by either 60, 90, 120 or 150 depending on the applicability of certain provisions of the Petroleum (Exploration and Production) Act 1991.

In the case of a production licence an annual fee is payable calculated by multiplying the number of square kilometres included in the blocks to which the Namibia Licence related by 1500.

Participation Agreement

Serica Namibia entered into separate agreements (the "**Participation Agreements**") with NAMCOR and IEPL dated 7 October 2011 and 13 October 2011 respectively. The Participation Agreements contain largely standard provisions on many key areas, including in relation to confidentiality, assignment and termination.

The Licence Area for the Participation Agreement with NAMCOR comprises Blocks 2512A, 2513A, 2513B, 2612A (part) and 2613A (part).

The Licence Area for the Participation Agreement with IEPL comprises 2512A, 2513A, 2513B and 2612A (part).

The Participation Agreements set out that the parties' interests in and under the Namibia Licence are to be as follows:

- Serica Namibia: 85%
- NAMCOR: 10%
- IEPL: 5%

PART XII – ADDITIONAL INFORMATION

1. Responsibility

1.1 The Company and its Directors (whose names and functions appear in paragraph 12 of Part I (*Letter from the Chairman of Serica*)) accept responsibility for the information contained in this document and for compliance with the AIM Rules for Companies. To the best of the knowledge of the Company and the Directors (who have taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and contains no omission likely to affect its import.

1.2 Ryder Scott Company, L.P., whose address is 1100 Louisiana, Suite 4600, Houston, Texas 77010 USA, accepts responsibility for the information set out in Part V (*Competent Person's Report on the BKR Assets*). To the best of the knowledge of Ryder Scott Company, L.P. (who has taken all reasonable care to ensure that such is the case), the information contained in Part V (*Competent Person's Report on the BKR Assets*) and otherwise included in this document from the BKR CPR is in accordance with the facts and contains no omission likely to affect the import of such information.

1.3 Netherland, Sewell & Associates, Inc., whose address is Fulbright Tower, 1301 McKinney Street, Suite 3200, Houston, Texas 77010 USA, accepts responsibility for the information set out in Part VI (*Competent Person's Report on Serica*). To the best of the knowledge of Netherland, Sewell & Associates, Inc. (who has taken all reasonable care to ensure that such is the case), the information contained in Part VI (*Competent Person's Report on Serica*) and otherwise included in this document from the Serica CPR is in accordance with the facts and contains no omission likely to affect the import of such information.

2. The Company and its subsidiaries

2.1 The Company was incorporated and registered in England and Wales on 12 May 2005 under the Act as a public limited company with its current name and with the registered number 05450950. The Company is the holding company of the Serica Group.

2.2 The principal legislation under which the Company operates is the Act and the regulations made thereunder. The liability of the members is limited.

2.3 The Company is domiciled in the United Kingdom.

2.4 The website address of the Company for the purposes of AIM Rule 26 is http://www.serica-energy.com.

2.5 The Company's registered office is 52 George Street, London, W1U 7EA (telephone number 020 7487 7300 or, if dialling from outside the United Kingdom, +44 20 7487 7300).

2.6 The Company acts as the holding company of the Serica Group and, following Admission, will be the holding company of the Enlarged Group. On Admission, the Company will have the following significant subsidiary undertakings:

Name	Country of Incorporation and residence	Business Activity	Percentage ownership
Serica Holdings UK Ltd	England and Wales	Holding	100
Serica Energy Holdings BV	Netherlands	Holding	100 (indirect)
Serica Energy (UK) Ltd	England and Wales	E&P	100 (indirect)
Serica Sidi Moussa BV	Netherlands	Exploration	100 (indirect)
Serica Foum Draa BV	Netherlands	Dormant	100 (indirect)
Serica Energy Slyne BV	Netherlands	Exploration	100 (indirect)
Serica Energy Rockall BV	Netherlands	Exploration	100 (indirect)
Serica Energy Namibia BV	Netherlands	Exploration	100 (indirect)
Serica Glagah Kambuna BV	Netherlands	Dormant	100 (indirect)
Serica Energy Corporation	British Virgin Islands	Dormant	100 (indirect)
Asia Petroleum Development Ltd	British Virgin	Dormant	100 (indirect)

Name	Country of Incorporation and residence	Business Activity	Percentage ownership
	Islands		
Petroleum Development Associates (Asia) Ltd	British Virgin Islands	Dormant	100 (indirect)
Petroleum Development Associates (Lematang) Ltd	England and Wales	Dormant	100 (indirect)
Serica UK Exploration Ltd	England and Wales	Dormant	100 (indirect)
Serica Walvis Namibia BV	Netherlands	Dormant	100 (indirect)

2.7 Save for the undertakings set out in paragraph 2.6 of this Part XII (*Additional Information*), there are no undertakings in which the Company holds a proportion of the capital that is likely to have a significant effect on the assessment of its own assets and liabilities, financial position or profits.

3. Share capital

3.1 The Company was incorporated with 1 A Share of £50,000 and 200,000,000 ordinary shares of US$0.10 each.

3.2 The following summarises the changes that have occurred in the share capital of the Company from 1 January 2014 (being the date of commencement of the period from which historical financial information on the Company has been provided in this document) to the Latest Practicable Date.

- On 4 June 2015, the Company issued 13,500,000 ordinary shares at nominal value of US$0.10 each to BP as part of the acquisition of an 18% interest in UK blocks 23/26a (Area B) and 23/26b (Area B) containing the Erskine field. No cash proceeds were received by the Company in respect of the Ordinary Shares issued.

3.3 As at the Latest Practicable Date, the issued share capital of the Company comprises one A Share of £50,000 (paid up to one quarter of the nominal value) and 263,679,039 Ordinary Shares of US$0.10 each (all of which are fully paid). As at the Latest Practicable Date, the Company holds no treasury shares.

3.4 Pursuant to an ordinary resolution of the Company passed at the 2017 Annual General Meeting the Directors are generally and unconditionally authorised for the purposes of section 551 of the Companies Act to exercise all of the powers of the Company to allot shares and grant rights to subscribe for, or convert any security into, shares in the Company: (a) up to an aggregate nominal amount of US$8,789,301.30; and (b) up to a further aggregate nominal amount of US$8,789,301.30 in connection with a rights issue to (i) holders of ordinary shares in proportion (as nearly as practicable) to the respective number of Ordinary Shares held by them on the relevant record date; and (ii) holders of other classes of equity securities as required or permitted by the rights of those securities, but subject to such exclusions or other arrangements as the Directors may consider necessary or appropriate to deal with fractional entitlements, treasury shares, record dates or legal, regulatory or practical difficulties which may arise under the laws of, or the requirements of any regulatory body or stock exchange in any territory or any other matter whatsoever.

Such authorities expire on 30 June 2018, or if earlier, the date of the next annual general meeting of the Company, save that the Company may before such expiry make any offer or agreement which would or might require shares to be allotted or rights to be granted, after such expiry and the Directors may allot shares, or grant rights to subscribe for or to convert any security into shares, in pursuance of any such offer or agreement as if the authorities conferred by such resolution had not expired.

3.5 Pursuant to a special resolution of the Company passed at the 2017 Annual General Meeting, the Directors are empowered pursuant to sections 570(1) and 573 of the Companies Act to: (i) allot equity securities of the Company (as defined in section 560 of the Companies Act) for cash pursuant to the authority conferred by the resolution detailed at paragraph 3.4 above; and (ii) sell ordinary shares (as defined in section 560(1) of the Companies Act) held by the Company as treasury shares for cash, as if section 561 of the Companies Act did not apply to such allotment or sale. Such power is limited to the allotment of equity securities and sale of treasury shares for cash:

(a) in connection with or pursuant to an offer of or invitation to acquire equity securities (but in the case of the authority granted under the resolution described at paragraph 3.4(b) above, by way of a rights issue only) in favour of holders of ordinary shares in proportion (as nearly as practicable) to the respective number of ordinary shares held by them on the record date for such allotment (and holders of any other class of equity securities entitled to participate therein or if the directors consider it necessary, as permitted by the rights of those securities) but subject to such exclusions or other arrangements as the Directors may consider necessary or expedient to deal with fractional entitlements, record dates or legal or practical difficulties which may arise; and

(b) in the case of an allotment otherwise than pursuant to paragraph 3.4(a) above, up to an aggregate nominal amount of US$2,636,790.40.

Such powers expire on the expiry of the general authority conferred by the resolution in respect of paragraph 3.4 above, save that the Company may before such expiry make any offer or agreement that would or might require equity securities to be allotted, or treasury shares to be sold, after such expiry, and the Directors may allot equity securities or sell treasury shares in pursuance of any such offer or agreement as if the power conferred by such resolution had not expired;

4. Options and awards under share schemes to Directors

As at the Latest Practicable Date, the following Options have been granted to Directors under an individual option agreement by the Company and are outstanding under the existing 2005 Plan:

	Number of shares subject to option	Exercise Price (£)	Date of grant	Expiry date
Antony Craven Walker	1,000,000	0.12	17 July 2015	16 July 2025
Antony Craven Walker	1,000,000	0.18	17 July 2015	16 July 2025
Antony Craven Walker	500,000	0.24	17 July 2015	16 July 2025
Total	**2,500,000**			

All options awarded since December 2009 have a three-year vesting period. Under the 2005 Plan, when awarding options to Directors, the Company's remuneration committee is required to set performance conditions, in addition to the vesting provisions, before vesting can take place. The options granted in July 2015 were all awarded at exercise prices higher than the market price at the time of the grant to establish firm performance targets.

In addition, the following awards will be granted to Directors as soon as reasonably practicable following the publication of this document under a deed of grant under the newly adopted Serica Energy plc Long Term Incentive Plan which was approved by the Board on 20 November 2017:

Director	Total number of shares to be granted subject to Deferred Bonus Share Awards	Exercise price
Antony Craven Walker	225,000	Nil
Mitchell Flegg	225,000	Nil
TOTAL	**450,000**	—

Deferred Bonus Share Awards involve the deferral of the Directors' bonuses into awards over shares in the Company. They are structured as nil-cost options and may be exercised up until the fifth anniversary of the date of grant. The Deferred Share Bonus Awards will vest on the later of the date of Completion and 31 January 2019. They are not subject to performance conditions; however, they are conditional on Completion, subject to the Board determining otherwise.

Director	Total number of shares to be granted as Performance Share Awards	Exercise price
Antony Craven Walker	1,500,000	Nil
Mitch Flegg	1,500,000	Nil
TOTAL	**3,000,000**	**—**

Performance Share Awards are subject to performance conditions based on average share price growth targets to be measured by reference to dealing days in the period of 90 days ending immediately prior to the expiry of a three-year performance period starting on the date of grant of a Performance Share Award. Performance Share Awards are structured as nil-cost options and may be exercised up until the tenth anniversary of the date of grant. They are not subject to Completion. Performance Share Awards will be formally granted (via the execution of a deed of grant) as soon as reasonably practicable following the publication of this document.

5. Articles of Association

The Company has no statement of objects in its Articles and accordingly its objects are unrestricted in accordance with the provisions of the Companies Act.

The following is a summary of the Articles, which are available for inspection at the address specified in paragraph 2.5 of this Part XII (*Additional Information*). The Articles, which were adopted on 25 June 2010, contain provisions, among others, to the following effect:

5.1 Limited Liability

The liability of the members is limited to the amount, if any, unpaid on the shares held by them.

5.2 Voting

Subject to paragraph 5.6 below and to any special rights or restrictions as to voting rights which any shares may for the time being be held, on a show of hands, every member or authorised corporate representative present has one vote and every proxy present has one vote except if the proxy has been duly appointed by more than one member and has been instructed by (or exercises his discretion given by) one or more of those members to vote for the resolution and has been instructed by (or exercises his discretion given by) one or more other of those members to vote against it, in which case a proxy has one vote for and one vote against the resolution. On a poll, every member present in person or by proxy or by corporate representative has one vote for every share of which he is the holder or in respect of which his appointment as proxy or corporate representative has been made. In the case of joint holders, the vote of the person whose name stands first in the register of members and who tenders a vote is accepted to the exclusion of any votes tendered by any other joint holders. The holders(s) of the A Share is entitled to the same voting rights as the holders of Ordinary Shares.

5.3 Transfer of Shares

A Shareholder may transfer all or any of his Ordinary Shares (a) in the case of shares in certificated form, by an instrument of transfer in any usual form, or in such other form as the Board may approve, and executed by or on behalf of the transferor and, where the share is not fully paid, by or on behalf of the transferee; and (b) in the case of shares in uncertificated form, by means of the relevant system concerned.

The Board may, in its absolute discretion, refuse to register any instrument of transfer of any share in certificated form which is not fully paid up (but not so as to prevent dealings in listed shares from taking place on an open and proper basis). The Board may also refuse to register any instrument of transfer of a certificated share (whether fully paid or not) unless the instrument of transfer (a) is lodged, duly stamped, at the registered office, or such other place as the Board may decide, for registration, accompanied by the certificate for the shares to be transferred and such other evidence (if any) as the Board may reasonably require to prove the title of the intending transferor; (b) is in respect of only one class of share; and (c) is in favour of not more than four transferees. The Board may refuse to register a transfer of share in uncertificated form to a person who is to hold it thereafter in certificated form in any case where the Company is entitled to refuse (or is excepted from the requirement) under the CREST Regulations to register the transfer.

The holder(s) of the A Share shall not be entitled to sell, transfer, renounce, charge, donate or otherwise dispose of the A Share (or any interest therein) save upon any change of trustee to new or remaining trustees of the trust or settlement the beneficiaries or potential beneficiaries of which are exclusively all Shareholders.

5.4 **Dividends**

The Shareholders shall be entitled to receive from time to time upon determination by the Directors (whose decision shall be final), a dividend subject to the Company having sufficient distributable reserves and subject to the withholding of any applicable taxes. The Company may by ordinary resolution declare dividends to Shareholders provided that no dividend shall exceed the amount recommended by the Directors. The Directors may from time to time declare and pay such interim dividends on shares of any class as appear to the Directors to be justified by the profits of the Company available for distribution.

Except as otherwise provided by the Articles or the rights attached to shares, all dividends shall be declared and paid according to the amounts paid up on the shares on which the dividend is paid.

No dividend or other money payable in respect of a share shall bear interest against the Company. Any dividend which has remained unclaimed for a period of 12 years from the date when it became due for payment shall, if the Directors so resolve, be forfeited and cease to remain owing by the Company.

No dividend shall be declared or paid to the holder(s) of the A Share.

5.5 **Return of Assets on a Winding Up**

On a return of assets on liquidation or capital reorganisation or otherwise, the assets of the Company remaining after the payment of its liabilities will be applied, first, in payment to the holder(s) of the A Share the sum of £50,000, and, second, in paying to the holders of the Ordinary Shares the balance of such assets in proportion to the amounts paid up on or credited as paid up (excluding any premium) on ordinary shares held.

A liquidator may, with the authority of a special resolution of the Company, divide among the members in specie the whole or any part of the assets of the Company, and may for such purposes value any assets and determine how the division shall be carried out as between members or different classes of members. The liquidator may, with the like sanction, vest the whole or any part of the assets in trustees on trust for the benefit of the members as he may with the like sanction determine. No member will be compelled to accept any assets upon which there is a liability.

5.6 **Suspension of Rights**

If a member or any other person appearing to be interested in shares held by such member has been given a notice under section 793 of the Companies Act and has failed in relation to any shares (the "default shares") to supply to the Company the information required under such notice within 14 days of the date of the notice, unless the Directors otherwise determine, (a) the member shall not be entitled in respect of the default shares to be present or to vote at any general meeting or at any separate meeting of holders of any class of shares or on any poll; and (b) where the default shares represents at least 0.25% of their class (excluding any shares held in treasury):

- any dividend payable in respect of the default shares may be withheld by the Company;
- other than in certain circumstances, no transfer of any default shares held in certificated form will be registered; and
- the directors may require the Operator of a relevant system to convert the default shares into certificated form to enable the Company to deal with the default shares in accordance with the Articles.

Any new shares in the Company issued in right of default shares will be subject to the same sanctions as apply to the default shares.

5.7 **Modification of Rights**

Whenever the capital of the Company is divided into different classes of shares, the rights attached to any class may, subject to the provisions of the Companies Act and unless otherwise provided by the terms of issue of that class, be varied or abrogated either with the consent in writing of the holders of not less than three quarters in nominal value of the issued shares of the class (excluding any shares held in treasury) or with the sanction of a special resolution passed at a separate meeting of such holders. The quorum at any such separate meeting (other than an adjourned meeting) shall be two persons holding or representing by proxy at least one-third in nominal value of the issued shares of the relevant class (excluding any shares held in treasury) and at an adjourned meeting those persons present shall constitute a quorum.

5.8 **Forfeiture of Shares**

If a call or instalment of a call remains unpaid on any share after it has become due and payable, the Directors may give the person from whom it is due not less than 14 clear days' notice requiring payment of the amount unpaid together with any interest which may have accrued. If the requirements of a notice are not complied with, any share in respect of which it was given may (before the payment required by the notice is made) be forfeited by a resolution of the Board. The forfeiture shall include all dividends declared and other monies payable in respect of the forfeited shares and not paid before the forfeiture.

A forfeited share may be sold, re-allotted or otherwise disposed of, upon such terms and in such manner as the Board shall decide either to the person who was before the forfeiture the holder of the share or to any other person.

5.9 **Borrowing Powers**

The Directors shall restrict borrowings of the Company and exercise all voting and other rights or powers of control exercisable by the Company in relation to its subsidiary undertakings so as to secure (in respect of subsidiary undertakings, only so far as by such exercise it can secure) that the aggregate principal amount of all borrowings by the Serica Group (excluding any borrowings owed by any Serica Group Company to another Serica Group Company) outstanding at any time shall not, without previous sanction of an ordinary resolution, exceed an amount equal to four times the adjusted capital and reserves (as determined in accordance with the Articles).

5.10 **Directors**

(a) Appointment and retirement of Directors

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

The Directors may, or the Company by ordinary resolution may, appoint a person who is willing to act as a director, and is permitted by law to do so, to be a director, either to fill a vacancy or as an additional Director.

At each annual general meeting there shall retire from office by rotation (a) all directors who held office at the time of each of the two preceding annual general meetings and who did not retire at either of them; and (b) if the number in (a) is less than one third of the relevant directors additional directors, together with those retiring under (a) above, equal to one third shall retire.

(b) Directors' remuneration

Unless otherwise determined by the Company by ordinary resolution, directors who do not hold executive office shall be entitled to such fees for their services as the Directors may determine, not exceeding in the aggregate an annual amount of £400,000. Any Director who holds any other office in the Company or serves on any committee of the Board, or who performs services which the Directors consider go beyond the ordinary duties of a Director may be paid such additional remuneration as the Directors may determine. The Directors may appoint one or more Director to any executive office of the Company and such appointment may be made for such term, at such remuneration and on such other conditions as the Directors think fit.

(c) Management by Directors

The business of the Company shall be managed by the Directors who, subject to the provisions of the Articles and to any directions given by special resolution to take or refrain from taking specified action, may exercise all the powers of the Company.

(d) Meetings of Directors

A Director may, and the Secretary on the request of a Director shall, call a meeting of the Directors. The quorum necessary for the transaction of the business of the Directors may be fixed from time to time by the Directors and unless so fixed at any other number shall be two.

(e) Voting of Directors

Save as specifically provided in the Articles of Association, a Director shall not vote on (or be counted in the quorum in respect of) any resolution of the Board concerning a matter in which he has, directly or indirectly, a material interest (other than an interest in shares, debentures or other securities of, or otherwise in or through, the Company) unless his interest arises only because the case falls within the circumstances specified in the Articles, including where:

(i) the resolution relates to the giving to a third party of a guarantee, security or indemnity in respect of an obligation of the Company or any of its subsidiary undertakings for which the Director has assumed responsibility in whole or part under a guarantee or indemnity or by the giving of security;

(ii) the resolution relates to the purchase or maintenance for any Director(s) of insurance against liability;

(iii) his interest arises by virtue of his being or intending to become a participant in the underwriting or sub-underwriting of an offer of any shares in or debentures or other securities of the Company for subscription, purchase or exchange; and

(iv) the resolution relates to another company in which he does not hold an interest in shares representing 1% or more of any class of the equity share capital or voting rights of that company.

Where proposals are under consideration concerning the appointment (including fixing or varying the terms of appointment) of two or more Directors to offices or place of profit with the Company or anybody corporate in which the Company is interested, a separate resolution may be put in relation to each Director. In such case each of the Directors concerned (if not debarred from voting as described above) is entitled to vote (and will be counted in the quorum) in respect of such resolution except that concerning his own appointment.

5.11 **Annual General Meetings and General Meetings**

An annual general meeting of the Company and all other general meetings of the Company shall be called by at least such minimum period of notice as is prescribed or permitted under the Companies Act.

No business shall be transacted at any general meeting unless a quorum is present. Two persons entitled to vote on the business to be transacted, each being a member or a proxy for a member or a duly authorised corporate representative shall be a quorum.

If a quorum is not present within half an hour from the time appointed for the meeting or if during a meeting a quorum ceases to be present, the meeting shall stand adjourned to such other time and place as the chairman of the meeting may determine.

6. Directors and their interests

6.1 The interests of the Directors and of persons connected with them (within the meaning of sections 252 to 256 of the Act) all of which are beneficial unless otherwise stated in the issued share capital of the Company, were and the existence of which is known to them or could, with reasonable diligence, be ascertained by the Directors, as at the date of this document:

	As at the latest Practicable Date	
Name	**Number of Ordinary Shares**	**Percentage of existing issued ordinary share capital**
Antony Craven Walker[(1)]	7,357,694	2.79%
Mitchell Flegg	184,445	0.07%
Neil Pike[(2)]	505,000	0.19%
Ian Vann	267,935	0.10%
Totals	**8,315,074**	**3.15%**

(1) 6,448,810 Ordinary Shares were held by Antony Craven Walker and 908,884 by Rathbones (pension funds). As a result of the death in 2015 of his wife, Christine Elizabeth Walker, the beneficial interest in her pension plan was ceded in 2016 by the trustees of the pension plan to their son in accordance with his late wife's wishes. Accordingly, Antony Craven Walker's stated holding of 7,357,694 Ordinary Shares does not include 472,222 Ordinary Shares of US$0.10 each in the Company which were previously recorded as being held in the pension plan of his wife and aggregated with his own holdings.

(2) 190,000 ordinary shares were held by Neil Pike's Spouse, Romayne Pike and 185,000 Ordinary Shares by Luska Limited (in which Neil Pike has a 5.1% interest and his wife has a 22.1% interest) as at 31 December 2015. In January 2016, Neil Pike notified the Company that he had transferred 130,000 Ordinary Shares in the Company to his ISA, and his wife also transferred 190,000 Ordinary Shares in the Company to her ISA. Following these transfers, Mr Pike's beneficial interest in the Company (which includes that of his wife) remains unchanged at 505,000 Ordinary Shares.

6.2 Details of the options and awards granted to Directors are set out in paragraph 4 of this Part XII (*Additional Information*).

6.3 The Directors hold, and have during the five years preceding the date of this document held, the following directorships or partnerships (other than the Company):

Director	**Current directorships/ partnerships**	**Previous directorships/ partnerships**
Antony Craven Walker	Serica Holdings UK Limited Serica Energy (UK) Limited	Firstearl Marine and Aviation Limited (*dissolved*) Arconas Luxembourg S.a.r.l.
Neil Pike	Luska Limited	n/a
Ian Vann	Scotland Yard Adventure Centre	Spectraseis AG
Mitchell Flegg	Greenoaks Advisory Limited	Serica Energy (UK) Limited Serica Holdings UK Limited Serica UK Exploration Limited Circle Oil plc Circle Oil Maroc Limited Circle Oil Egypt Limited Circle Oil Tunisia Limited Circle Oil Oman Limited Circle Oil Jersey Limited

6.4 Save as set out in paragraph 6.5 below, none of the Directors has:

(a) any unspent convictions relating to indictable offences (including fraudulent offences);

(b) any bankruptcies or entered into any individual voluntary arrangements with his creditors;

(c) been a director of any company at the time of, or within the 12 months preceding, any receivership or liquidation (including compulsory liquidation, creditors' voluntary liquidation), administration, company voluntary arrangement or any composition or arrangement with creditors generally or any class of creditors of such company;

(d) been a partner of any partnership at the time of, or within the 12 months preceding, any compulsory liquidation, administration or partnership voluntary arrangement of such partnership;

(e) had any of their assets made the subject of any receivership or have been a partner of a partnership at the time of or within the 12 months preceding any assets thereof being the subject of a receivership;

(f) received any public criticism by any statutory or regulatory authorities (including recognised professional bodies) or have been disqualified by a court from acting as a director of a company or from acting in the management or conduct of the affairs of a company.

6.5 Circle Oil plc went into a creditors voluntary liquidation on 20 February 2017, and Circle Oil Jersey Limited went into administration on 26 January 2017. Mr Flegg was a director of both of these companies at the time of, or within the period of twelve months prior to the dates on which these events occurred. Crestworth Limited went into voluntary dissolution in 2008, Telerian Systems Limited went into voluntary dissolution in 2010 and Firstearl Marine and Aviation Limited was dissolved by way of a voluntary strike-off in July 2017. Mr Craven Walker was a director of each of these companies at the time of or within the period of twelve months prior to the dates on which these events occurred. Vann Consulting Ltd went into voluntary dissolution in May 2010. Mr Vann was a director of this company at the time this event occurred.

6.6 Save as disclosed in this paragraph 6.6 or paragraph 6.1 of this Part XII (*Additional Information*) as at the Latest Practicable Date, none of the Directors are aware of any interest which represents 3% or more of the issued share capital of the Company as at the date of this document or of any persons who, directly or indirectly, jointly or severally, exercise or could exercise control over the Company:

	As at the Latest Practicable Date	
Shareholder	**Number of Ordinary Shares**	**Percentage of existing issued ordinary share capital**
GRG UK Oil LLC	46,090,576	17.48%
Mr D.R and Mrs D.A Hardy	27,418,100	10.40%
Canaccord Genuity Group Inc	18,241,496	6.92%
AXA Investment Managers	18,123,265	6.87%
Hargreaves Lansdown Asset Management	16,735,419	6.35%
Interactive Investor Trading	14,590,677	5.53%
BP Exploration Operating Company	13,500,000	5.12%

6.7 None of the major shareholders of the Company set out above has different voting rights from any other holder of Ordinary Shares in respect of any Ordinary Share held by them. The Directors are not aware of any arrangements, the operation of which may at a subsequent date result in a change of control of the Company.

6.8 None of the Directors or any person connected with them (within the meaning of section 252 of the Act) is interested in any related financial product referenced to the Ordinary Shares (being a financial product whose value is, in whole or in part, determined directly or indirectly by reference to the price of the Ordinary Shares including a contract for difference or a fixed odds bet).

6.9 Excluding professional advisers otherwise named in this document and trade suppliers and save as disclosed in paragraph 6.10 of Part XII (*Additional Information*), no person has at any time within the 12 months preceding the date of this document received, directly or indirectly, from the Company or entered into any contractual arrangement to receive, directly or indirectly, from the Company on or after Admission any fees totalling £10,000 or more or securities in the Company with a value of £10,000 or more or any other benefit with a value of £10,000 or more.

6.10 A summary of payments aggregating over £10,000 made to any government or regulatory authority or similar body by the Enlarged Group or on behalf of it, with regards to the acquisition of, or maintenance of, its assets as at the date of this document, is set out in the table below.

(a) Serica

Government Authority	**Description**	**Amount (US$)**
Namibia Licence		
Ministry of Mines and Energy (Namibia)	Licence fee (Namibia Licence)	119,379(1)
PETROFUND	Petroleum Training and Education Fund	25,000
Columbus		
Department for Business, Energy and Industrial Strategy (UK)	Licence fees (Licences P.1314 and P.101)	96,769(2)(3)
Slyne		
Department of Communications, Climate Action and Environment (Ireland)	Licence fee (Licence FEL 1/06)	43,469(4)
Department of Communications, Climate Action and Environment (Ireland)	Expanded Offshore Support Group (EOSG) (Ireland) (Licence FEL 1/06)	20,562(4)
Petroleum Infrastructure Programme (PIPCO RSG Limited)	Irish Shelf Petroleum Study Group (ISPSG) (Ireland) (Licence FEL 1/06)	102,813(4)
Rockall		
Department of Communications, Climate Action and Environment (Ireland)	Licence fee (Licence FEL 4/13)	31,571(4)
Department of Communications, Climate Action and Environment (Ireland)	Petroleum Exploration and Production Promotion and Support (Licence FEL 4/13)	20,562(4)
Petroleum Infrastructure Programme (PIPCO RSG Limited)	Irish Shelf Petroleum Study Group (ISPSG) (Ireland) (Licence FEL 4/13)	102,813(4)
Department of Communications, Climate Action and Environment (Ireland)	Licence fee (Licence FEL 1/09)	13,312(4)
Petroleum Infrastructure Programme (PIPCO RSG Limited)	Irish Shelf Petroleum Study Group (ISPSG) (Ireland) (Licence FEL 1/09)	102,813(4)

Note:
(1) Paid in Namibia Dollars, converted at an exchange rate of US$1 = N$13.11.
(2) Net to Serica (50%).
(3) Paid in pounds sterling, converted at an exchange rate of £1 = US$1.31.
(4) Paid in Euro, converted at an exchange rate of EUR1 = US$1.18.

(b) BKR Assets

Government Authority	Description	Amount (£)
Bruce Field		
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 276)	166,800.00
OGA	OGA LEVY yearly charge (Licence 276)	65,444.77
Health & Safety Executive	Bruce Offshore Inspection & Prep	37,572.50
Health & Safety Executive	Bruce Offshore Inspection & Prep	22,211.00
Health & Safety Executive	Bruce Offshore Diving Inspection	64,132.60
Keith Field		
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 209)	15,225.00
OGA	OGA LEVY yearly charge (Licence 209)	65,444.77
Rhum Field		
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 198)	36,190.00
OGA	OGA LEVY yearly charge (Licence 198)	65,444.77(1)
Rhum Field (Non-Unit)		
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 566)	124,200.00
OGA	OGA LEVY yearly charge (Licence 566)	65,444.77(1)
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 975)	105,092.00
Department for Business, Energy and Industrial Strategy (UK)	Yearly licence fee (Licence 975)	113,176.00
OGA	OGA LEVY yearly charge (Licence 975)	65,444.77(1)

Note:

(1) A rebate of £5,466.09 was received in respect of this levy charge.

7. Directors' service agreements and letters of appointment

7.1 Directors

Details of titles and dates of appointment of the Directors are set out below:

Name	Title/function	Date of appointment
Antony Craven Walker	Executive Chairman	12 May 2005
Mitchell Flegg	Chief Executive Officer	21 November 2017
Neil Pike	Non-Executive Director	1 September 2005
Ian Vann	Non-Executive Director	1 July 2007

(a) Antony Craven Walker has entered into a service agreement with the Company dated 1 June 2015. The agreement is terminable on six months' notice given by Mr Craven Walker and 12 months' notice given by the Company. Under the agreement, Mr Craven Walker is entitled to an annual salary of £300,000 which is subject to review. For the year ended 31 December 2016, Mr Craven Walker received an annual salary of £300,000 in respect of services as Executive Chairman. In addition, he is entitled to a discretionary bonus and a non-discretionary bonus of 15% of his annual salary in the event of certain corporate events, including a significant equity fundraising, a significant new equity partner is secured or a combination of the Company with another company. Mr Craven Walker is entitled to first class travel expenses from his place of residence to any place of work in the United Kingdom. Mr Craven Walker is also entitled under his service agreement to illness and medical insurance, life insurance equal to three times his salary on death and travel insurance, however, he has not taken up these benefits. He is entitled to 25 days' annual leave (plus public and bank holidays) and, in the event of sickness absence, payment of full salary for up to 13 weeks and thereafter at 75% of his salary for 13 weeks in any calendar year. The agreement contains provisions entitling the Company to pay Mr Craven Walker in lieu of his notice period on termination and contains provisions allowing the Company to put Mr Craven Walker on garden leave during his period of notice. The agreement also contains: (i) three month post termination restrictive covenants against employing or enticing away key employees; and (ii) three month post termination restrictive covenants against competing with the Company or Group Companies in any of the countries in which the Group has interests or contemplates having interests at the time of termination of the service agreement.

(b) Mitchell Flegg has entered into a service agreement with the Company under which he has been appointed Chief Executive Officer. However, his continued appointment will be conditional upon Completion. If Completion does not occur, his employment may be terminated and, if his employment is terminated, he will be entitled to three months of his base salary only. The agreement is terminable on six months' notice given by Mr Flegg and 12 months' notice given by the Company. Under the terms of the agreement, Mr Flegg is entitled to an annual salary of £270,000 which is subject to annual review and deductions required by law. In addition, he is entitled to a discretionary bonus, illness and medical insurance for both him and his spouse or civil partner, life insurance equal to four times his salary on death and travel insurance. Mr Flegg is entitled to contributions from the Company into a pension scheme nominated by Mr Flegg of a minimum of 6% of his salary. His employer contribution entitlement may rise to up to 10% of his salary depending on his own contributions. If Mr Flegg chooses to opt-out of a pension scheme, he is entitled to receive a cash payment in monthly instalments of 10% of his salary in lieu of pension contributions. Mr Flegg is entitled to 25 days' annual leave (plus public and bank holidays) and, in the event of sickness absence, payment of full salary for up to 13 weeks and thereafter at 75% of his salary for 13 weeks in any calendar year. The agreement contains provisions entitling the Company to pay Mr Flegg in lieu of his notice period on termination and contains provisions allowing the Company to put Mr Flegg on garden leave during his period of notice. The agreement contains provisions entitling Mr Flegg to three months of his base salary in the event that there is a change of control of the Company and, within six months of that change of control, Mr Flegg's employment is terminated by reason of redundancy. The agreement also contains: (i) three month post termination restrictive covenants against employing or enticing away key employees; (ii) three month post termination restrictive covenants against competing with the Company or Group Companies in any of the countries in which the Group has interests or contemplates having interests at the time of termination of the service agreement; and (iii) three month post termination restrictive covenants against enticing away or endeavouring to entice away key customers of the Company or the Group.

(c) The non-executive Directors have entered into appointment letters with the Company with the dates of appointment set out in the table above. Under the terms of these letters, the non-executive Directors are entitled to an annual fee as set out below. The appointments are terminable by either party giving not less than three months' notice or in certain circumstances including misconduct or incapacity for more than 90 working days in 12 months, with immediate effect. The appointment letters contain provisions entitling the Company to pay the non-executive Directors in lieu of their notice periods. All of the non-executive Directors are covered by the Company's indemnity insurance for its directors and are entitled to be reimbursed for expenses incurred in the proper performance of their duties. The non-executive Directors are also entitled to be reimbursed for the cost of such independent professional advice as necessary for discharging their responsibilities provided that the matter is first discussed with the Board and the non-executive Director obtains a full estimate of the cost of such advice before obtaining it.

Name	Annual Fee (less deductions required by law)
Neil Pike	£40,000
Ian Vann	£40,000

(d) Antony Craven Walker and Mitchell Flegg will remain on the same terms under their current service agreements on Admission. Antony Craven Walker will be paid a cash bonus of £75,000 in connection with the Acquisition.

(e) The non-executive Directors will remain on the terms under their current appointment letters on and after Completion. However, there will be an increase, effective on Completion, for non-executive directors' fees of an additional £10,000 per annum for chairing a committee of the Company.

7.2 **Other service contracts**

Save as disclosed in paragraph 7.1 above, there are no existing or proposed service agreements between the Directors and the Company nor have any such service agreements been entered into or amended within six months of the date of this document.

8. Summary of Serica share option schemes

The Company operates three discretionary incentive plans: the Serica Energy Plc Long Term Incentive Plan (the "**LTIP**"), which was adopted by the Board on 20 November 2017 which permits the grant of share-based awards and the 2017 CSOP, which was adopted by the Board on 20 November 2017. The LTIP and the 2017 CSOP together are known as the "**Discretionary Plans**". The 2016 CSOP has been terminated with effect from 29 November 2017 and there are no outstanding options under the 2016 CSOP.

The Company also operates a historical discretionary share option plan, the 2005 Plan, which was adopted by the Board on 14 November 2005. Awards can no longer be made under the 2005 Plan, however, options remain outstanding under the 2005 Plan.

The Company also operates a tax-advantaged all-employee share-based incentive plan: the Serica Energy Share Incentive Plan (the "**SIP**"), which the Board adopted on 29 January 2009. The Board also plans on adopting a new savings-related share option plan, known as the Serica Energy 2018 Sharesave Plan (the "**Sharesave Plan**") in due course. Together, the SIP and the Sharesave Plan are known as the "**All Employee Plans**".

The main features of each of these plans are set out below.

8.1 **The Serica Energy Plc Long Term Incentive Plan**

The following is a summary of the principal terms of the LTIP.

(a) *Structure and Operation*

The LTIP is a discretionary share plan, under which the Board may grant the following elements under the LTIP:

(i) an award over shares for performance ("**Performance Share Award**") and/or an award to key executives upon their recruitment or in other exceptional circumstances ("**Retention Award**"); and

(ii) a deferral of any bonus into an award over shares ("**Deferred Share Bonus Award**").

Together, the Retention Awards, Performance Share Awards and Deferred Share Awards shall be known as "Awards".

(b) *Awards over shares*

(i) **Retention Awards**

Retention Awards are normally awarded to key executives upon their recruitment or, in exceptional circumstances, at the discretion of the Board.

Retention Awards normally vest on a fixed date or may vest in tranches over an extended period, and are subject only to continued employment with the Group on the relevant vesting date. Performance conditions do not apply to Retention Awards; however, they can be awarded in recognition of performance up to the date of grant.

(ii) **Performance Share Awards**

Performance Share Awards are normally granted to key executives and senior managers.

Performance Share Awards shall vest based on both continued employment with the Group and subject to the satisfaction of performance conditions. If circumstances occur which result in the performance conditions no longer being appropriate, the Board may, in its absolute discretion, vary or waive the performance targets, provided that such varied performance conditions are materially no more difficult to satisfy and such an amendment is considered fair and reasonable by the Board.

(iii) **Individual Limits: Retention Awards and Performance Share Awards**

The maximum aggregate market value of shares (at grant) that may be granted to an eligible employee under both Retention Awards and Performance Share Awards in any financial year shall be no more than 200% of base salary under normal circumstances. The maximum aggregate market value of shares that may be granted to an eligible employee under a Retention Award in any financial year shall be no more than 100% of base salary.

For these purposes, the market value of a share subject to an award shall be taken as being:

- the lower of 29 pence per share and the market value of a share subject to an award as at the date of grant of that award, but only in respect of initial awards granted or promised to be granted to employees on or shortly following the date of announcement of the Acquisition, or to certain key employees of BP who become eligible employees on Completion; and
- in respect of all other grants, calculated as at the date of grant of that award.

(c) *Deferred Share Bonus Award*

Deferred Share Bonus Awards are only granted to eligible employees who are entitled to a bonus, where it has been determined by the Board that a proportion of their bonus shall be deferred into an Award over shares.

To be eligible to receive a Deferred Share Bonus Award the individual must be employed and not under notice on the date of grant of the Deferred Share Bonus Award.

Individual Limit

The maximum aggregate market value of shares that may be granted to an eligible employee under Deferred Share Bonus Award in any financial year shall be no more than 100% of the relevant bonus, which is to be deferred, subject to a maximum bonus deferral equal to 100% of base salary.

For these purposes, the market value of a share subject to an award shall be taken as being:

- the lower of 29 pence per share and the market value of a share subject to an award as at the date of grant of that award, but only in respect of initial awards granted or promised to be granted to employees on or shortly following the date of announcement of the Acquisition, or to certain key employees of BP who become eligible employees on Completion; and
- in respect of all other grants, calculated as at the date of grant of that award.

8.2 **Common Features to Deferred Share Bonus Awards, Retention Awards and Performance Share Awards**

(a) *Form of Awards*

All Awards shall be capable of being structured as nil-cost option or nominal cost options or conditional share awards.

The terms of the LTIP provide for the grant of cash-based awards (over a notional number of shares) and for the cash settlement of awards.

(b) *Vesting of Awards/Exercise of Options*

The Board may, in its absolute discretion, specify the date on which an Award shall vest and, in the case of an option, become exercisable, provided that such determination is made on or before the date of grant.

In the absence of any determination by the Board to the contrary on or before the grant of a Performance Share Award, such awards shall normally vest and, in the case of an option, become exercisable on the third anniversary of the date of grant. Further, Performance Share Awards shall normally only be capable of vesting and, in the case of an option, become capable of exercise to the extent that the performance conditions applying to that Performance Share Award have been satisfied immediately prior to vesting.

The LTIP rules also permit any form of an Award to vest in tranches over a fixed proportion of the shares originally held at the date of grant on different dates.

Awards that have been structured as options shall normally be capable of exercise up until the day before the tenth anniversary of grant unless the Board determines that a shorter period shall apply at grant.

(c) *Leavers*

As a general rule, an Award will lapse upon a participant ceasing to hold employment or upon his or her ceasing to be a director within the Group.

However, if a participant ceases to be an employee or a director where the cessation of office or employment with the Group is due to death; permanent injury, ill-health or disability; retirement; the sale or transfer of the participant's employing company or business to a person who is not a member of the Company's group; redundancy; or any other reason permitted by the Board, in its absolute discretion (a "**Good Leaver**") then the following will apply:

(i) In relation to a Deferred Share Bonus Award, the Deferred Share Bonus Award shall normally vest in full on the date of cessation unless the Board, in its discretion, determines that it should instead vest on the normal vesting date. On the basis that Deferred Share Bonus Awards represent the deferral of a proportion of bonus already earned, the Deferred Share Bonus Award will not be reduced to take account of the fact that the participant ceased office or employment early. Vesting shall also be subject to conditions imposed on the Deferred Share Bonus Award, for instance completion of a transaction; however, the Board may, in its absolute discretion, waive such conditions of vesting.

(ii) In relation to a Retention Award and Performance Share Award such Awards will normally vest on the normal vesting date. Alternatively, the Board may, in its discretion, determine that the Award shall vest on or shortly following the date of cessation.

(iii) The extent to which a Retention Award and Performance Share Award vests will be determined by applying a time pro-rata reduction to the total number of shares held under the Retention Award and Performance Award to reflect the reduced period of time between the grant date and the date of cessation relative to the normal vesting period, unless the Board decides to waive or reduce the pro-rata reduction.

(iv) In relation to a Performance Share Award, unless the Board determines otherwise, performance conditions will be tested on either the date of cessation or the normal vesting date dependent on the date the Board determines the Performance Share Awards shall vest.

(d) *Dividend Equivalents*

The Board may decide that participants will receive a payment (in cash and/or shares) at the time of delivery of vested shares, of an amount equivalent to the dividends that would have been paid on those shares over the vesting period in the case of unexercised nil or nominal cost options. This amount may take into account the reinvestment of dividends.

The dividend equivalent shall not apply unless the Board determines otherwise on or prior to the grant of an Award.

(e) *Malus and Clawback*

The Board may, in its absolute discretion, decide within three years of the date of payment of a Bonus or a relevant Award vesting that a participant will be subject to clawback where, broadly, there has been a material misstatement in the Company's financial results, an error in assessing any applicable performance condition or if the participant's employment is terminated for gross misconduct.

The clawback, relating to any overpayment, may be satisfied by way of a reduction in the amount of any future bonus, the vesting of any subsisting or future share options/awards and/or the number of shares under any vested but unexercised option granted under the Plan, and/or a requirement to make a cash payment.

(f) *Amendments*

The Board may amend the LTIP and the terms of an Award at any time.

No alteration to the material disadvantage of a participant to existing Awards may be made without the approval of the affected participant, where only one participant is affected, or the approval of over 50% of the affected participants first having been obtained (where more than one participant is affected).

8.3 **Serica Energy Plc Share Option Plan 2005 (the "2005 Plan")**

The 2005 Plan was adopted on 14 November 2005. Options under the 2005 Plan can no longer be granted, as the 2005 Plan expired on 14 November 2015. However, as options remain outstanding under the 2005 Plan, the rules of the 2005 Plan have been described below under this paragraph 8.3 of Part XII (*Additional Information*).

(a) *Structure*

The 2005 Plan operates over Ordinary Shares.

(b) *Form of awards*

The 2005 Plan is set up with two parts, Part One allowing for the grant of options to directors, employees and consultants and Part Two allowing for the grant of such options to be made as Enterprise Management Incentive ("**EMI**") options as provided for under United Kingdom legislation.

Part One of the 2005 Plan was amended on 8 December 2009 in order to extend the maximum period for exercise of options awarded under the Serica 2005 Option Plan from 5 years to 10 years. In addition, the minimum vesting period was changed to three years.

(c) *Performance conditions*

The Company's remuneration committee ("**Committee**") may determine that performance conditions apply to the exercise of options. A Performance Condition may be varied or waived if the Committee in its absolute discretion thinks fit where events occur which causes the Committee to consider that such variation or waiver shall result in a fairer condition and one which would be no more and no less difficult to satisfy than that originally imposed.

(d) *Exercise of options*

Options will normally become exercisable three years after the date of grant. Options may not be exercised later than the tenth anniversary of the date of grant.

(e) *Leavers*

If a participant ceases to hold office or be employed within the Group or ceases to be a consultant to the Group for any reason other than a "Good Leaver" reason, as specified below, the option will lapse unless the Committee in its absolute discretion, within 40 days after the participant ceases to hold office or be employed or be a consultant to the Group, permits (if at all) the participant to exercise all or part of the Option within such period as the Committee shall determine.

If a participant ceases to hold office or employment or ceases to be a consultant to the Group by reason of injury, ill-health or disability, dismissal by reason of redundancy, retirement, or the participant's employing entity ceasing to be a member of the Group, or in the case of a non-executive director of the Company or a subsidiary of the Company, the director ceasing to hold office by reason of his office not being renewed following an annual vote of the shareholders of the Company ("Good Leaver") the participant may exercise the option within 6 months after ceasing to hold office or being so employed. Performance conditions shall be waived upon cessation of employment and awards will not be pro-rated for time.

If a participant ceases to hold office or be employed within the Group or ceases to be a consultant by reason of their death, the option may be exercised by their personal representatives within the period of 12 months from the date of death.

(f) *Amendments*

The Company may at any time by resolution of the Board alter or add to all or any of the provisions of the 2005 Plan, provided that:

(i) no alteration or addition shall be made without the participant's prior written consent which would adversely affect the subsisting rights of the participant; or cause the option insofar as it is a qualifying option granted pursuant to Part Two of the 2005 Plan to fail to remain a qualifying EMI option; and

(ii) no alternation or addition shall be made, without the consent of the shareholders in general meeting which would substantially improve the subsisting rights of a participant.

(g) *Corporate Actions*

In the event of a takeover, or if another company acquires control of the Company by way of general offer to acquire the Company's shares, a compulsory acquisition or by way of a court-sanctioned scheme of arrangement (a **"Specified Event"**), all unvested options become exercisable. The option may be exercised within the period of 40 days from the date of the Specified Event, and thereafter options shall lapse to the extent that they have not been exercised. The Committee may in its absolute discretion extend the period of 40 days referred to above for a period of up to six months or if throughout the period of six months the participant is prevented by the Company's share dealing code from either exercising his option or from selling sufficient shares.

Under the 2005 Plan, in the event of the passing of a resolution for the voluntary winding-up of the Company, options or awards will become exercisable. Where the corporate action forms part of an internal re-organisation, unless the Committee determines otherwise, options shall not become exercisable but may be rolled-over into an option over shares in the new controlling company of equivalent value.

(h) *Plan Limits*

Options may be granted in respect of authorised and unissued shares, provided that the maximum number of shares available for issuance under the 2005 Plan or any other plan, subject to increase by the Board and the approval of Shareholders shall not exceed 10% of the issued and outstanding shares on the date of grant.

The aggregate number of shares issued or which may be issued in respect of options granted to any one eligible employee under the 2005 Plan shall not exceed 5% of the issued share capital as at the date of grant in any one twelve month period.

The aggregate number of shares issued or which may be issued in respect of options granted to all eligible employees who are hired by the Company for the purpose of conducting Investor Relations Activities under the 2005 Plan shall not exceed 2% of the issued share capital as at the date of grant in any one twelve month period.

The aggregate number of shares issued or which may be issued in respect of options granted to any one eligible employee who is a consultant under the 2005 Plan shall not exceed 2% of the issued share capital as at the date of grant in any one twelve month period.

8.4 Serica Energy plc 2017 Company Share Option Plan

As the Board has now approved and adopted the new LTIP, the Board has decided to adopt the new 2017 CSOP at the same time, which is in line with the LTIP rules and in particular, which contains the same plan dilution limits as the LTIP. The rules of the 2017 CSOP are largely the same as the 2016 CSOP, save that the 2017 CSOP contains different plan dilution limits and amendment provisions.

The following is a summary of the principal terms of the 2017 CSOP.

(a) *Structure*

The 2017 CSOP operates over Ordinary Shares.

(b) *Form of awards and limits*

Under the 2017 CSOP, options take the form of either:

(i) options to acquire shares granted under Part A of the 2017 CSOP; or

(ii) options to acquire shares granted under Part B of the 2017 CSOP, which are UK tax-advantaged options governed by relevant statutory provisions ("**Tax-Advantaged Options**").

The Board shall determine the number of shares over which an option is granted under Part A and/or Part B of the 2017 CSOP, subject to the statutory limits under Part B.

(c) *Performance conditions*

The Board may determine that performance conditions will apply to the exercise of options, though in respect of the Tax-Advantaged Options these conditions must consist of only objective conditions and any alteration of such conditions must not cause the revised target to be more difficult to satisfy than the original target.

(d) *Exercise price*

No consideration shall be payable for the grant of an option.

The exercise price of an option will not be less than the greater of:

(i) the market value of a share on the dealing day immediately preceding the date of grant, or averaged over the three dealing days immediately preceding the date of grant; and

(ii) in the case of options over unissued shares, the nominal value of a share,

but subject to any adjustment on a variation of share capital.

(e) *Exercise of options*

Options will normally become exercisable three years after the date of grant. Options may not be exercised later than the tenth anniversary of the date of grant.

If the Board so determines, options granted under Part A may be satisfied in whole or in part by transfer or issue of shares, without payment from the option holder, equivalent in value to the gain which would be made by the option holder on exercise.

(f) *Leavers*

Options will normally lapse where the option holder ceases to hold office or employment with the Group. Options will not lapse where the cessation of office or employment with the Group is due to injury, disability, ill-health, redundancy, retirement, the transfer of the option holder's employment in connection with a business sale, the company with which the option holder holds office or employment ceasing to be a member of the Group, or any other reason if the Board so determines (a "**Good Leaver**").

Where an option holder ceases employment prior to the normal vesting date for a Good Leaver reason, an option will continue and become exercisable on its normal vesting date for a period of six months. Where an option holder ceases employment after the normal vesting date for a Good Leaver reason a vested option may be exercised during a period of six months from the day following the date of cessation. On the death of an option holder, options shall become exercisable for a period of twelve months.

(g) *Extent of Vesting*

Where, prior to the end of the vesting period, an option holder ceases employment for a Good Leaver reason or there is a corporate action, the number of shares in respect of which an option is exercisable will, unless the Board determines otherwise, be pro-rated on the basis of the proportion of the vesting period which has elapsed to the date of cessation or the corporate action (as applicable).

(h) *Amendments*

The Board may amend the 2017 CSOP any time provided that the Board cannot make alterations which would abrogate or adversely affect the subsisting rights of a participant without participants' consent.

(i) *Overseas plans*

The 2017 CSOP contain provisions which permit the Board to establish a further plan for the benefit of overseas employees based on the 2017 CSOP (as applicable) but modified as necessary or desirable to take account of overseas tax, exchange control or securities laws. Any new shares issued under such plans would count towards the individual and overall plan limits outlined above.

(j) *Sub-plan for Non-Employees*

Options may also be granted under Part C of the 2017 CSOP on similar terms to Part A of the 2017 CSOP, the non-tax-advantaged part, for non-employees and services providers to the Group. The plan limits described at paragraph 8.5(e) of this Part XII (*Additional Information*) below shall not apply to Part C.

8.5 **Common Features to the Discretionary Plans**

(a) *Adoption and Operation*

The operation of the Discretionary Plans will be supervised by the Board or an authorised committee of the Board.

(b) *Eligibility*

Participation in the Discretionary Plans shall be at the absolute discretion of the Board.

Options granted under Part A of the 2017 CSOP and the LTIP may be granted to any of the employees or executive directors of the Company or its subsidiaries.

Options granted under Part B of the 2017 CSOP may be granted to any full time director or employee of the Company or its subsidiaries that has not, at the date of grant, had a material interest in a close company within the preceding 12 months. Options may not be granted under Part B of the 2017 CSOP to executive directors of the Company or other members of the executive committee of the Company.

The Board may also implement a sub-plan of the LTIP such that awards may also be made to non-employees (including non-executive directors or consultants) under a sub-plan to the LTIP for non-employees which will be structured in the same way as the LTIP.

(c) *Timing of Awards/Options*

Options under the 2017 CSOP may and Awards under the LTIP, save in exceptional circumstances or in connection with the recruitment or retention of an eligible employee, only be granted within a period of 42 days from the dealing day following the date of announcement by the Company of its interim or final results (or as soon as practicable thereafter if the Company is restricted from being able to grant options or awards, or make invitations, during such period). Options or awards may also be granted within 42 days of adoption of the Discretionary Plans.

Options under the 2017 CSOP may not be granted more than ten years after the date of approval by Shareholders and Awards under the LTIP not be granted more than ten years after the date of adoption by the Board.

(d) *Corporate Actions*

In the event of a takeover, or if another company acquires control of the Company by way of general offer to acquire the Company's shares, a compulsory acquisition, under a court-sanctioned scheme of arrangement, a cross-border merger or upon a voluntary winding-up of the Company (not being an internal corporate reorganisation or reconstruction) (a "**Specified Event**"), all unvested Awards under the LTIP held at the time shall vest to the extent determined by the Board and options under the 2017 CSOP shall normally become exercisable.

In exercising its discretion under the LTIP upon a Specified Event and determining the extent to which a Performance Share Award shall vest, the Board shall determine the number of vested shares of that Performance Share Award having regard to any performance condition and any other condition imposed on the vesting of the Award.

By default, Performance Share Awards and Retention Awards shall not be subject to a pro-rata reduction. However, the Remuneration Committee may, in its discretion, acting fairly and reasonably, decide to apply a time *pro rata* reduction based on the period from the date of grant to the date of the Specified Event.

Where, prior to the end of the vesting period, there is a Specified Event, the number of shares in respect of which a 2017 CSOP option is exercisable vests will, unless the Board determines otherwise, be pro-rated on the basis of the proportion of the vesting period which has elapsed to the Specified Event.

Deferred Share Bonus Awards shall vest early and in full upon the occurrence of a Specified Event and shall not be subject to a time pro-rata reduction.

Under the Discretionary Plans, in the event of the passing of a resolution for the voluntary winding-up of the Company, options or awards will become exercisable for a period of two months. In the event of a demerger of a substantial part of the Group's business, a special dividend or a similar event affecting the value of the shares to a material extent, options (other than Tax-Advantaged Options) or Awards under the Discretionary Plans may be adjusted as set out below or the Board may allow options or Awards to become exercisable for a period of two months, or such other period as the Board may permit. Where the corporate action forms part of an internal re-organisation, unless the Board determines otherwise, options or Awards shall not become exercisable but may be rolled-over into an option over shares in the new controlling company of equivalent value.

(e) *Plan Limits*

Shares may be newly issued, transferred from treasury or market purchased for the purposes of the Discretionary Plans.

In relation to all of the Discretionary Plans, the number of shares issuable subject to outstanding awards or options granted within the previous ten years and when added to the number of shares issued for the purpose of awards and options granted within the previous ten years cannot exceed 10% of the Company's ordinary share capital in issue immediately prior to the proposed date of grant under all employees' share schemes adopted by the Company. Market purchase shares shall not count towards this limit.

For information purposes only, under the terminated 2016 CSOP, the number of shares subject to outstanding awards or options granted within the previous ten years when added to the number of shares issued for the purpose of awards and options granted within the previous ten years could not exceed 5% of the Company's ordinary share capital. As mentioned above, the 2016 CSOP has been terminated. This 5% limit does not apply to the 2017 CSOP, which shall only be subject to the 10% limit expressed above, this is so as to ensure that the Company's new LTIP is aligned with dilution limits under its discretionary share option plan.

Any Tax-Advantaged Options granted under the 2017 CSOP shall be limited to take effect so that, after such a grant, the aggregate market value of all of a participant's shares under Part B of the 2017 CSOP or any other tax-advantaged CSOP shall not exceed the limit set out in Schedule 6 of the Income Tax (Earnings and Pensions) Act 2003, which is currently £30,000.

These limits do not include rights to shares which have been released, lapsed or otherwise become incapable of exercise.

Treasury shares will count as new issue shares for the purpose of these limits for so long as institutional investor bodies consider that they should be so counted.

8.5 **Serica Energy plc Share Incentive Plan**

(a) *Introduction*

The following is a summary of the principal terms of the Serica Energy plc Share Incentive Plan (the "**SIP**").

(b) *Structure and Operation*

The operation of the SIP is supervised by the Board or an authorised committee of the Board.

The SIP is an "all-employee" share incentive plan and is intended to be a tax-advantaged scheme under Schedule 2 of the Income Tax (Earnings and Pensions) Act 2003 ("**Schedule 2**").

The SIP operates over ordinary shares in the capital of Serica Energy plc ("**shares**").

(c) *Eligibility*

Each time that the Board decides to make an award under the SIP, all UK resident tax-paying employees of the Group participating in the SIP must be offered the opportunity to participate. Other employees of the Group may be permitted to participate at the Board's discretion.

This SIP provides that the Board may require employees to have completed a qualifying period of employment (as determined by the Board and in line with the requirements of Schedule 2 from time to time) before they may participate in the SIP.

(d) *Type of Awards*

Under the SIP, eligible employees may be:

(i) awarded free shares up to a value of £3,600 (‘‘**Free Shares**’’) each year;

(ii) offered the opportunity to buy shares up to a maximum value of the lesser of £1,800 and 10% of the employee's pre-tax salary each year (‘‘**Partnership Shares**’’);

(iii) given up to two free shares (‘‘**Matching Shares**’’) for each Partnership share bought; and/or

(iv) allowed or required to purchase shares using any dividends received on shares held in the SIP (‘‘**Dividend Shares**’’).

The Board may increase these limits in the future should the relevant legislation change the maximum levels of participation referred to above.

(e) *SIP Trust*

The SIP operates through a UK resident trust (the ‘‘**SIP Trust**’’). The trustee(s) of the SIP Trust purchases or subscribes for shares that are awarded to or purchased on behalf of participants in the SIP. A participant will be the beneficial owner of any shares held on their behalf by the trustee(s) of the SIP Trust (‘‘**SIP Trustees**’’).

(f) *Free Shares*

The Board may determine, at its discretion, whether or not to award Free Shares. The basis of an allocation of Free Shares will be at the Board's discretion but Free Shares must be awarded on the basis of an objective formula based on the employees' earnings, length of service, number of hours worked or a fixed number or value or on the basis of objective performance criteria measuring the objective success of the individual team, division or business. Any alteration of performance conditions must not cause the revised target to be more difficult to satisfy than the original target

The maximum value of Free Shares which an employee may receive in a tax year may not exceed £3,600 (or such other limit as may be permitted by Schedule 2 from time to time).

There will be a holding period of between three and five years (or such other period as may be permitted by Schedule 2 from time to time) during which the employee cannot withdraw the Free Shares from the SIP Trust unless the participant ceases to be employed by the Group. The duration of this holding period will be determined by the Board each time Free Shares are awarded.

The Board, in its discretion, may provide that the Free Shares will be forfeited if the participant ceases to be employed by the Group during a specified period other than because of death, injury, disability, redundancy, retirement or the sale of the individual's employing company or business out of the Group (each a ‘‘**SIP Good Leaver Reason**’’) or on death.

(g) *Partnership Shares*

The Board may allow employees to use their pre-tax salary to buy Partnership Shares. The maximum amount that an eligible employee may use to acquire Partnership Shares is the lower of £1,800 and 10% of the individual's pre-tax salary in any tax year (or such other limits as may be permitted by Schedule 2 from time to time). The minimum amount of any deduction cannot be greater than £10.

The salary allocated to acquire Partnership Shares can be accumulated for a period of up to 12 months or Partnership Shares may be purchased out of deductions from the employee's pre-tax salary as and when those deductions are made. In either case, Partnership Shares must be bought within 30 days of the end of the period of accumulation or the deduction from pay.

Once acquired, Partnership Shares are not capable of forfeiture and may be withdrawn from the SIP by the employee at any time.

(h) *Matching Shares*

The Board may, in its discretion, offer free Matching Shares to employees who have purchased Partnership Shares. The Board may award up to a maximum of two Matching Shares for every Partnership share purchased. The Board, in its discretion, may provide that the Matching Shares will be forfeited if the participant ceases to be employed by the Group during a specified period other than for a SIP Good Leaver Reason, on death or if he withdraws he related withdraws the related Partnership Shares.

There is a holding period of between three to five years (or such other period as may be permitted by Schedule 2 from time to time) during which the employee cannot withdraw the Matching Shares from the SIP Trust, unless the employee ceases to be employed by the Group. The duration of the holding period will be determined by the Board each time Matching Shares are awarded.

(i) *Dividend Shares*

The Board may allow or require a participant to reinvest the whole or part of any dividends paid on shares held in the SIP.

Dividend shares must be held in the SIP Trust for no less than three years, unless the employee ceases to be employed by the Group. If an employee ceases to be employed by the Group, all of their Dividend shares shall be transferred to them as soon as practicable following cessation of their employment.

(j) *Corporate Actions*

If any offer, compromise, arrangement or scheme is made which affects the Free Shares or Matching Shares the SIP Trustees must notify the participants. Each participant may direct how the Trustees shall act in relation to the participant's Plan Shares. In the absence of a direction, the SIP Trustee shall take no action.

(k) *Participant Rights*

Any shares allocated under the SIP and held in the SIP Trust will rank equally with shares then in issue (except for rights arising by reference to a record date prior to their allotment). In the event of a rights issue, employees will be able to direct the trustee(s) of the 2017 SIP Trust as to how to act in respect of the shares held in the SIP on their behalf.

(l) *Amendments*

The Board may, at any time, amend the provisions of the SIP in any respect with the SIP Trustee's prior written consent provided that no amendment may adversely prejudice the rights attaching to any Plan Shares awarded to or acquired by participants nor may any alteration be made giving the participating companies a beneficial interest in Plan Shares.

(m) *Overseas plans*

The board may at any time and without further formality establish further plans in overseas territories, any such plan to take account of local tax, exchange control or securities laws, regulation or practice. Shares made available under any such plan will count against the limit on the number of new shares that may be issued under the SIP.

(n) *Termination*

The SIP may be terminated by the Board at any time or by ordinary resolution of the Company's Shareholders in general meeting.

8.7 **The Serica Energy 2018 Sharesave Plan**

(a) *Introduction*

The Board intends on adopting the Serica Energy 2018 Sharesave Plan (the "**Sharesave Plan**") next year. Set out below is a short summary of the proposed principal terms of the Sharesave Plan which the Board intends to adopt. The terms of this plan are subject to approval of the Board and the Company's remuneration committee.

(b) *Structure and Operation*

The operation of the Sharesave Plan will be supervised by the Board or an authorised committee of the Board.

The Sharesave Plan is a UK tax advantaged share option scheme and is intended to comply with the requirements of Schedule 3 to the Income Tax (Earnings and Pensions) Act 2003 ("**Schedule 3**").

The Sharesave Plan will operate over ordinary shares in the capital of Serica Energy plc.

(c) *Eligibility*

The Sharesave Plan should provide that employees and full-time directors of the Company and any designated participating subsidiary who are UK resident taxpayers are eligible to participate. The Board may in its discretion extend participation under the Sharesave Plan to other employees or directors of participating members of the Company who do not meet these requirements.

The Sharesave Plan should provide that the Board may require employees to have completed a qualifying period of employment (a "**Qualifying Period**") before they may apply for the grant of an option. The Board may specify a Qualifying Period of up to five years.

(d) *Timing of Invitations*

Invitations to participate in the Sharesave Plan may be issued within 42 days after (i) the approval of the Sharesave Plan by the Board; (ii) the announcement of the Company's results for any period, (iii) the date on which any change to the legislation affecting UK Schedule 3 Sharesave schemes takes effect, (iv) the date on which a new UK savings contract prospectus is announced or takes effect, or (v) the end of a closed period. Invitations may also be issued at any other time at which the Board determines that the circumstances are sufficiently exceptional to justify the grant of options.

(e) *Grant of Options*

Under the Sharesave Plan, options will normally be granted within 30 days (or 42 days if applications are scaled back) of the first day by reference to which the option price is set.

The number of shares over which an option is granted will be such that the total option price payable for those shares will normally correspond to the proceeds on maturity of the related savings contract.

No invitation may be issued under the Sharesave Plan more than 10 years after the Sharesave Plan has been approved by the Board.

(f) *Individual Participation*

Participation in the Sharesave Plan requires employees to agree to make regular monthly contributions to an approved savings contract of three or five years (or such other period permitted by the legislation).

Subject to the limits set out below, the Board will determine the maximum amount that an employee may contribute under a savings contract linked to options granted under the Sharesave Plan.

Monthly savings by an employee under the Sharesave Plan and all savings contracts linked to options granted under any Schedule 3 tax-advantaged scheme may not exceed the statutory maximum (currently £500 per month in aggregate).

(g) *Option Price*

The option price per share under the Sharesave Plan will be the market value of a share when invitations to participate in the Sharesave Plan are issued less a discount of up to 20% (or, in the case of an option to subscribe, the nominal value of a share if higher), or such other maximum discount permitted under the governing legislation. Market value is determined in accordance with the provisions of the Taxation of Chargeable Gains Act 1992 and is agreed in advance of the date of a grant under the Sharesave Plan with HMRC.

(h) *Exercise and Lapse of Options*

Options granted under the Sharesave Plan will normally be exercisable for a six month period from the end of the relevant three or five year savings contract.

Any options not exercised within the relevant exercise period will lapse.

An option may be exercised before the end of the relevant savings period, for a limited period, on the death of a participant or on his or her ceasing to hold office or employment within the Company's group by reason of injury, disability, redundancy, retirement, the sale or transfer out of the group of his or her employing company or business, their employer ceasing to be an associated company or for any other reason (other than in the event of dismissal for misconduct) provided in such case the option was granted more than three years previously.

(i) *Corporate Actions*

Rights to exercise options early for a limited period also arise if another company acquires control of the Company as a result of a general offer or upon a scheme of arrangement or becomes bound or entitled to acquire shares under the compulsory acquisition provisions. In such circumstances, any subsisting offer must be exercised before the earliest of either the expiry of six months commencing on the date of the event described above or the expiry of any period during which any person is bound or enticed to acquire shares under the compulsory acquisition provisions. An option may be exchanged for an option over shares in the acquiring company if the participant so wishes and the acquiring company agrees.

If the Company passes a resolution for a voluntary winding-up, any subsisting option must be exercised within a period of up to six months of the passing of that resolution or it lapses.

(j) *Overall Plan Limits*

The Sharesave Plan may operate over new issue shares, treasury shares or shares purchased in the market.

In any 10 year period, the Company may not issue (or create the possibility of issuing) more than 10% of the issued ordinary share capital of the Company under the Sharesave Plan and any other employee share plan adopted by the Company.

Treasury shares will count as new issue shares for the purposes of these limits unless institutional investors decide that they need not count.

(k) *Amendments*

The Board may, at any time, amend the provisions of the Sharesave Plan in any respect.

(l) *Overseas plans*

The board may at any time and without further formality establish further plans in overseas territories, any such plan to take account of local tax, exchange control or securities laws, regulation or practice. Shares made available under any such plan will count against the limit on the number of new shares that may be issued under the Sharesave Plan.

8.8 **Common Features to the Discretionary Plans and the All Employee Plans**

(a) *Participants Rights*

Until options are exercised and awards vest, participants have no voting or other rights in respect of the shares subject to their options (save in respect of dividend equivalents under the LTIP – see above).

(b) *Variation of share capital*

The number of shares subject to options and awards may be adjusted, in such manner as the Board may determine, following any variation of share capital of the Company or, except for Tax-Advantaged Options under the 2017 CSOP, a demerger of a substantial part of the Group's business, a special dividend or a similar event affecting the value of shares to a material extent.

In relation to the SIP, on a rights issue, the participants may instruct the SIP Trustee to dispose of some of the rights arising from the Plan Shares to obtain enough funds to exercise remaining rights.

(c) *Non-transferable and non-pensionable*

Options are non-transferable, save to personal representatives following death, and do not form part of pensionable earnings.

(d) *Governing law*

The plans will be governed by English law.

9. Working capital

In the opinion of the Directors, having made due and careful enquiry, the working capital available to the Enlarged Group will be sufficient for its present requirements, that is, for at least the next 12 months from the date of Admission.

10. United Kingdom Taxation

The following is a general guide to certain limited aspects of the UK tax treatment of holding and disposing of the Ordinary Shares, and does not purport to be a complete analysis of all the potential

UK tax considerations thereof. The comments set out below do not constitute tax advice and are based on current United Kingdom tax law as applied in England and Wales and HM Revenue & Customs' published practice (which may not be binding on HM Revenue & Customs) as at the date of this document, both of which are subject to change, possibly with retrospective effect.

The information provided below applies only to shareholders (a) who are resident (and, in the case of individuals, domiciled) for UK tax purposes in the UK; (b) who hold their shares as investments (other than in an individual savings account); and (c) who are the absolute beneficial owners thereof.

The discussion does not address all possible tax consequences relating to an investment in any relevant shares. Certain categories of investors, including those carrying on certain financial activities, (including market makers, brokers, dealers, intermediaries and persons connected with depository arrangements or clearance services), those subject to specific tax regimes or benefiting from certain reliefs and exemptions and those for whom the shares are employment-related securities may be subject to special rules and this summary does not apply to such investors. Such investors should consult their professional advisors without delay.

Shareholders or prospective shareholders who are resident or otherwise subject to taxation in a jurisdiction outside the United Kingdom, or who are in any doubt about their tax position, are also advised to consult their own professional advisers immediately.

10.1 **Dividends on the Ordinary Shares**

(a) *UK tax resident individual shareholders*

All dividends received by a shareholder who is an individual in respect of the Ordinary Shares will form part of that shareholder's total income for income tax purposes and will constitute the top slice of that income. A nil rate of income tax will apply to the first £5,000 (reducing to £2,000 for the 2018/19 tax year) of taxable dividend income received by that shareholder in a tax year.

Where the dividend income is above the dividend allowance, an individual shareholder will not be subject to tax on dividend income above the allowance to the extent that, treating that income as the top slice of the shareholder's income, that income would be within that individual's personal allowance. Any amount in excess of the nil rate and the personal allowance (if applicable) will be taxed at the relevant rate. The rates are 7.5% to the extent that the excess amount falls within the basic rate tax band, 32.5% to the extent that the excess amount falls within the higher rate tax band and 38.1% to the extent that the excess amount falls within the additional rate tax band.

(b) *UK tax resident corporate shareholders*

Dividends paid to shareholders who are subject to UK corporation tax are likely to fall within one or more of the classes of dividend qualifying for exemption from corporation tax, although the exemptions are not comprehensive and are also subject to anti-avoidance rules. Such shareholders should consult their own professional advisers.

10.2 **Disposals of Ordinary Shares**

A disposal or deemed disposal of Ordinary Shares by a shareholder who is resident in the UK for tax purposes may give rise to a liability to UK tax on capital gains (in the case of shareholders who are individuals) or UK corporation tax on chargeable gains (in the case of shareholders within the charge to UK corporation tax) depending upon the shareholder's circumstances and subject to any available exemption or relief.

(a) *UK tax resident individual shareholder*

For an individual shareholder within the charge to UK capital gains tax, a disposal (or deemed disposal) of the Ordinary Shares may give rise to a chargeable gain or an allowable loss for the purposes of capital gains tax. The rate of capital gains tax on the disposal of shares is 10% (for the tax year 2017/2018) for basic rate taxpayers and 20% (for the tax year 2017/2018) for higher or additional rate taxpayers. An individual shareholder is entitled to realise an annual exempt amount of gains (currently £11,300 for the tax year 2017/2018, increasing to £11,700 for the 2018/19 tax year) without being liable to tax.

(b) *UK tax resident corporate shareholders*

For a corporate shareholder within the charge to UK corporation tax, a disposal (or deemed disposal) of the Ordinary Shares may give rise to a chargeable gain or allowable loss for the purposes of UK corporation tax, depending on the circumstances and subject to any available exemption or relief. Indexation allowance may reduce the amount of any chargeable gain for these purposes, but will not create or increase any allowable loss. The rate of UK corporation tax is 19% for the financial years commencing 1 April 2017, 1 April 2018 and 1 April 2019. Legislation has been enacted which reduces the rate of UK corporation tax to 17% for the financial year commencing 1 April 2020.

10.3 **Stamp Duty and Stamp Duty Reserve Tax**

The statements below are intended as a general guide to the current position. They do not apply to certain intermediaries who are not liable to stamp duty or stamp duty reserve tax or (except where stated otherwise) to persons connected with depositary arrangements or clearance services who may be liable at a higher rate.

No stamp duty or stamp duty reserve tax should generally be payable on the issue of Ordinary Shares. Nor should any UK stamp duty or stamp duty reserve tax arise on transfers of Ordinary Shares on AIM (including instruments transferring Shares and agreements to transfer Ordinary Shares) for so long as:

(a) the Ordinary Shares are admitted to trading on AIM, but are not listed on any market (with the term "listed" being construed in accordance with section 99A of the Finance Act 1986), and this has been certified to Euroclear; and

(b) AIM continues to be accepted as a "recognised growth market" as construed in accordance with section 99A of the Finance Act 1986.

In the event that either of the above assumptions does not apply, stamp duty or stamp duty reserve tax may apply to transfers of Ordinary Shares in certain circumstances.

11. Material contracts

The following contracts have been entered into by members of the Group (a) in the two years immediately preceding the date of this document and are, or may be material, or (b) were entered into outside the two years immediately preceding the publication of this document and contain provisions under which a member of the Group has an obligation or entitlement which is material to the Group as at the date of this document.

11.1 **Serica**

(a) *Introduction Agreement*

Pursuant to an agreement dated 30 November 2017 between Peel Hunt, the Company and the Executive Directors of the Company, Peel Hunt has agreed with the Company to act as nominated adviser in connection with Admission. The Agreement is conditional *inter alia* upon:

- the Resolution being passed at the General Meeting;
- the Acquisition Agreement having been completed in accordance with its terms subject to Admission; and
- Admission.

Under the Introduction Agreement, the Company and the Executive Directors have agreed to give certain warranties to the Company in connection with the Enlarged Group and this document. In addition, the Company has agreed to give Peel Hunt an indemnity which is customary for a transaction of this nature as well as granting Peel Hunt the right to terminate the Introduction Agreement at any time up to Admission in certain circumstances which are customary for a transaction of this nature. The Company has agreed to pay Peel Hunt a fee for its services pursuant to the Introduction Agreement and to pay its out of pocket expenses.

(b) *Acquisition Agreement*

Pursuant to the Acquisition Agreement made between BP and Serica UK, dated 21 November 2017, Serica UK will acquire 36% in the Bruce field (BP is retaining 1%), BP's entire 34.83% interest in the Keith field and BP's entire 50% interest in the Rhum field. In addition to the BKR Assets, BP is also transferring to Serica UK its interests in certain blocks in neighbouring non-producing areas adjacent to the Bruce, Keith and Rhum fields, but which do not themselves form part of the fields.

The effective date of the Acquisition is 1 January 2018, so Serica UK will be entitled to a share of the net cash flows from the BKR Assets during the interim period from the effective date of the Acquisition to the date of Completion. Subject to the conditions to the Acquisition Agreement being satisfied, completion of the assignments for all the licence interests in the BKR Assets will occur at the same time, which is expected to be in mid-2018.

The consideration payable by Serica UK to BP is as follows:

- initial consideration of £12.8 million in cash payable on Completion. This amount will be adjusted for net cash flow from the BKR Assets between the effective date and the date of Completion. The Directors anticipate that the net cash flow to which Serica UK is entitled between the effective date and the date of Completion will be more than the amount of the Initial Consideration resulting in a net payment to Serica UK from BP on Completion.
- up to £16 million payable in January 2019 or thereafter provided that the Rhum R3 Well has achieved a specified minimum production threshold for 90 days during the first year following completion of the workover of the well anticipated to take place in 2018. If the production threshold is not met, this element of the consideration will not be paid. In addition, even if the well production does meet the production targets, 50% of this consideration will be deferred if gas production from the Rhum field still requires the payment of blending fees by 1 January 2019 or if an alternative solution has been found which delivers an equivalent economic benefit as the removal of the requirement for blending. If on 1 January 2020, the requirement for blending fees remains or if there has been not been an alternative solution, then such remaining 50% of the consideration will not be payable.
- up to a further £23.1 million in aggregate payable in three annual instalments (of up to approximately £7.7 million each) in respect of 2019, 2020 and 2021 if Rhum field production volumes and sales prices meet or exceed certain agreed levels. The amounts payable will be reduced if Rhum field production and the price achieved for sales of Rhum gas do not meet the agreed levels.
- BP will also receive a share of net pre-tax cash flows from the BKR Assets of 60% in 2018 (including during the interim period between the effective date (1 January 2018) and Completion), 50% in 2019 and 40% in each of 2020 and 2021. The net cash flow shares are calculated on a monthly basis. No amounts are payable by Serica UK unless this cash flow is positive and amounts are repayable to Serica UK in the event of negative cash flow, up to the amount Serica UK has already paid in the same year. Net negative cash flow during the year can be carried forward to be offset against positive cash flow in subsequent years. The arrangements in relation to Serica UK and BP sharing net cash flows from the BKR Assets are set out in the Net Cash Flow Sharing Deed.
- Serica UK will pay additional consideration equal to 30% of BP's retained share of decommissioning costs when due, reduced by the tax relief that BP receives on those costs. This element of consideration is capped by the amount of net cash flow received by Serica UK as a result of the Acquisition.
- Serica UK will also pay deferred consideration equal to 90% of its share of the realised value of oil in the Bruce pipeline at the end of field life.

Completion of the Acquisition Agreement is conditional upon *inter alia* the following conditions being satisfied prior to Completion:

- the OGA's consent to the assignment of the BKR Assets to Serica UK and the transfer of operatorship of the BKR Assets to Serica UK;
- a waiver or expiry of pre-emption rights of Iranian Oil Company (UK) Limited, BP's partner on the Rhum field;
- the approval of BP's partners in the BKR Assets to the assignment of the BKR Assets and the transfer of operatorship to Serica UK (the requirement for such approval is customary for transactions of this type);
- clearance being sought by Serica UK and received from HMRC that the tax treatment of the sharing of the net cash flows from the BKR Assets pursuant to the Net Cash Flow Sharing Deed will be applied as intended;
- receipt by Serica UK of an OFAC licence and arrangement of satisfactory banking facilities to conduct Rhum operations;
- receipt by BP of renewals of licences P.209 and P.198 in relation to the BKR Assets;

- the amendment of certain decommissioning security agreements and operating agreements in relation to the BKR Assets to give effect to the retention by BP of its liability for decommissioning and voting rights on decommissioning matters pursuant to the Acquisition; and
- the passing of the Resolution at the General Meeting.

In addition, Completion will not take place unless Admission also takes place. In addition to the conditions under the Acquisition Agreement, Serica UK has the right to terminate the Acquisition Agreement prior to Completion in the event of catastrophic damage to the whole or a material element of facilities relating to the Bruce field, the Keith field and/or the Rhum field. Each of Serica UK or BP can also terminate the Acquisition Agreement if there is a cessation of production from the Rhum field due to sanctions.

BP will retain liability for all the costs of decommissioning facilities and wells existing at Completion relating to the BKR Assets. Serica UK will pay for the costs of decommissioning new facilities.

Further, the parties have agreed that BP shall control the voting rights of Serica UK in relation to decommissioning matters that concern existing facilities.

Each of BP and Serica UK has given warranties and indemnities each to the other under the Acquisition Agreement which are customary for a transaction of this nature.

The Acquisition Agreement places obligations on BP to consult with Serica UK on all material matters arising in relation to the BKR Assets and to get the approval of Serica UK for decisions on material issues relating to the Rhum 3 Well workover project during the period between the date of the Acquisition Agreement and Completion. Serica UK's approval is required for BP to vote in favour of new budgets and work programmes and for unbudgeted expenditures above a certain level during this interim period. Under the Acquisition Agreement, Serica UK requires the approval of BP to sell interests in the BKR Assets.

In the event that BP were to sell Bruce to one of its co-venturers pursuant to certain clauses of the Bruce Unitisation and Unit Operating Agreement, BP have granted certain rights to Serica which allow Serica to seek to acquire the Rhum field on its own. However, Serica would not do so without seeking further Shareholder approval for such a transaction.

(c) *Product Sales Agreements*

Serica UK's share of natural gas production from the Bruce, Keith and Rhum fields will be delivered at St Fergus via the Frigg UK pipeline and sold under a life of field gas sales agreement between BP Gas and BP which will be novated to Serica UK on Completion. The gas will be sold at daily spot prices determined as the Heren Day Ahead Mid-Point Price for natural gas at the National Balancing Point ("**NBP**"). This is subject to normal deductions comprising marketing fees, transportation charges to the NBP, entry capacity charges and imbalance charges. There may also be price adjustments related to potential over and under deliveries.

Serica UK's share of oil production from the Bruce, Keith and Rhum fields is exported via Forties Pipeline System will be sold to BP Oil under an oil sales agreement between BP Oil and BP which will be novated to Serica UK on Completion. The oil will be sold at daily spot prices for Forties Blend Crude Oil published in the Platts Crude Oil Market Wire subject to adjustment for sulphur content and deductions for demurrage costs.

Serica UK's uncontracted share of NGL production from the Bruce, Keith and Rhum fields will be sold to BP Oil under NGL sales agreements between BP and BP Oil which will be novated to Serica UK on Completion. The NGLs will be sold at the following prices:

- for Butane, at the fixed price for metric tonne(s) FOB Grangemouth as shall be posted under the heading ANSI (Argus North Sea Index) as published in Argus International LPG Report and effective for the month of bill of lading minus a typical market discount;
- for Naphtha, at the fixed price per metric tonne(s) in tank in situ Grangemouth as shall be the arithmetic average of the mean quotes for Naphtha under the heading CARGOES CIF NORTH WEST EUROPE as published in Platts European Marketscan minus a typical market discount; and
- for Propane, at the fixed price per metric tonne(s) FOB Grangemouth as shall be the posted quote for Propane under the heading ANSI (Argus North Sea Index) as published in Argus International LPG Report and effective for the month of bill of lading minus a typical market discount.

Small quantities of other hydrocarbon products arise from processing at the delivery terminals for the Frigg UK and Forties Pipeline System. Existing agreements for the sales of these products are expected to be transferred from BP to Serica UK on Completion.

(d) *Prepayment Facility*

Under the Prepayment Facility made between Serica UK and BP Gas and dated 21 November 2017, BP Gas has agreed to provide for drawings to cover the Initial Consideration and the cost of premiums payable for gas price puts (hedging instruments which set a floor price for certain volumes of gas production from the BKR Assets) which have been purchased by Serica UK in conjunction with signing the Acquisition Agreement. The Prepayment Facility of up to £16 million carries interest at one month LIBOR plus 4.5% per annum compounded monthly and added to the outstanding amount and has a maximum duration of three years from initial drawings. Repayments will commence six months after Completion and be based on 35% of Serica UK's retained share of gas sales revenues from the BKR Assets including any related price hedging gains and after deduction of those proportions due to BP under the Net Cash Flow Sharing Deed.

In the event that Serica raises additional finance through equity issue or asset sale, BP Gas has the right to require repayment of any amounts outstanding under the Prepayment Facility.

(e) *Net Cash Flow Sharing Deed*

The Net Cash Flow Sharing Deed, which will be entered into on Completion between BP and Serica UK (and which is an agreed form document pursuant to the Acquisition Agreement), sets out the methodology for calculating BP's share of future net cash flows from the BKR Assets according to the percentages described in the description of the Acquisition Agreement at paragraph 11.1(b) of this Part XII (*Additional Information*).

Net cash flow is defined as all field revenues less operating and transportation costs less capital expenditure on Bruce field facilities the parties agree is necessary to achieve a specified level of Bruce production less the cost of the Rhum 3 Well workover project anticipated to take place in 2018.

Serica UK proposes to seek confirmation from HMRC that the cash flow payments payable to BP under the Net Cash Flow Sharing Deed will qualify for ring fence tax deductions for Serica. As stated above, such confirmation from HMRC is a condition to Completion.

(f) *Security Agreements*

The Security Agreements, which (other than the deed of guarantee dated 21 November 2017 between Serica, BP and BP Gas) will be entered into on Completion between, among others, BP and Serica UK and are agreed form documents pursuant to the Acquisition Agreement, provide that Serica UK will provide certain financial guarantees to BP in respect of its obligations under the Acquisition Agreement, Net Cash Flow Sharing Deed and the gas sales arrangements as described below:

- Serica UK will grant to BP a fixed and floating charge over Serica UK's interests in the BKR Assets solely in relation to Serica UK's financial obligations to BP under the Net Cash Flow Sharing Deed;
- Serica will provide a parent company guarantee in relation to, among other matters, Serica UK's obligations under the Gas Sales Agreement and the Prepayment Facility up to a maximum amount of £20 million, and other certain obligations under the Acquisition Agreement but not including the consideration equal to 30% of BP's post-tax decommissioning costs.
- following release of the fixed and floating charge over the BKR Assets following the last payments under the Net Cash Flow Sharing Deed, Serica UK will make advance payment for a portion of the estimated consideration equal to 30% of BP's post-tax share of decommissioning costs. Such portion shall be based on the estimated future amount of such consideration divided by the estimated number of years of remaining production of the BKR Assets.

(g) *Transfer of Operatorship Agreement*

Under the Transfer of Operatorship Agreement made between BP and Serica UK and dated 21 November 2017 the parties have agreed to jointly develop and implement a transition plan and budget for transitioning operations in relation to the BKR Assets to Serica UK during the period between the date of the Acquisition Agreement and Completion. The Transfer of Operatorship Agreement sets out the obligations of each party in relation to the transition and certain obligations on Serica UK in relation to the staff engaged on the BKR Assets being transferred from BP.

The obligations of the parties in relation to the process of transitioning operatorship include:

- provision by BP of access to information and personnel for Serica UK;
- cooperation between the parties to secure the necessary regulatory approvals;
- transfer of inventory to Serica UK as soon as practicable following the transfer date and access for Serica UK prior to this date, as necessary;
- cooperation between the parties to effect the transfer of contracts, as appropriate. Federal Contracts (being those which are not exclusive to the BKR Assets) will not be transferred to Serica UK;
- identification of IT software and hardware to be transferred; and
- consent of BP to Serica UK operating in its name in relation to any environmental consents not transferred by the date of Completion provided that Serica UK indemnifies BP from all liability arising from operations after the date of Completion.

The Transfer of Operatorship Agreement sets out mutual hold harmless indemnities for damage and harm to each party's property and staff, including consequential losses. These follow the UKCS oil industry standard form.

The transfer is subject to the Transfer of Undertakings (Protection of Employment) Regulations and requires that Serica UK preserves the employment terms and conditions for transferred staff for a minimum period of 1 year. Serica UK has no obligations in respect of pension benefits accruing to transferred staff up to the Completion Date.

(h) *Those material contracts described in Part XI (Summary of Key Licences and Agreements)*

The contracts described in Part XI (*Summary of Key Licences and Agreements*) have been entered into by members of the BP Group in relation to the BKR Assets (a) in the two years immediately preceding the date of this document and are, or may be, material, or (b) were entered into outside the two years immediately preceding the publication of this document and contain provisions under which a member of the BP Group has an obligation or entitlement which is material to the BP Group in relation to the BKR Assets as at the date of this document and which are expected to be assigned or novated to a member of the Serica Group at Completion.

11.2 **BKR Assets**

Those material contracts and licences described in Part XI (*Summary of Key Licences and Agreements*).

12. Litigation

12.1 **Serica**

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) covering at least the 12 months preceding the date of this document which may have, or have had, a significant effect on the financial position or profitability of the Company and/or the Group.

12.2 **BKR Assets**

There are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which the Company is aware) covering at least the 12 months preceding the date of this document which may have, or have had, a significant effect on the financial position or profitability of the BKR Assets for which the Company may be liable after Completion, however please see Part IV (*Risk Factors*) and the risk factor entitled *"There is a dispute between BP's partner to the Rhum field and the Bruce field partners relating to Bruce field costs*".

13. No significant change

13.1 **Serica**

There has been no significant change in the financial or trading position of the Group since 30 June 2017, the date to which the last unaudited interim financial statements were prepared.

13.2 **BKR Assets**

There has been no significant change in the financial or trading position of the BKR Assets since 30 June 2017, the date to which the financial information on the BKR Assets set out in Part VII (*Unaudited Historical Financial Information on the BKR Assets*) was prepared.

14. Related party transactions

14.1 Serica

Save as described in the Group's audited consolidated historical financial information for the three financial years ended 31 December 2014, 31 December 2015 and 31 December 2016, as set out in Note 28, 31 and 30 respectively thereof, incorporated by reference in Part VIII (*Historical Financial Information on Serica*), there are no related party transactions entered into by the Company during the financial years ended 31 December 2014, 31 December 2015 and 31 December 2016, the six months ended 30 June 2017 or during the period from and including 30 June 2017 to and including the Latest Practicable Date.

14.2 BKR Assets

BP, the seller of the BKR Assets, is interested in 13,500,000 Ordinary Shares representing 5.12% of the Company's issued share capital. BP is entitled to vote on the Resolution.

15. Public takeover bids

15.1 City Code

The City Code applies to the Company and will, *inter alia*, regulate all transactions howsoever effected which have as their objective or potential effect (directly or indirectly) obtaining or consolidating control of the Company. Control for such purposes is defined as an interest or interests in shares carrying 30% or more of the voting rights of a company, irrespective of whether such interests give de facto control.

15.2 Mandatory Bids

Under the City Code, where:

(a) any person acquires, whether by a series of transactions over a period of time or not, an interest in shares which (taken together with shares in which he is already interested, and in which persons acting in concert with him (as such expression is defined in the City Code) are interested) carry 30% or more of the voting rights of a company; or

(b) any person, who together with persons acting in concert with him, is interested in shares which in the aggregate carry not less than 30% of the voting rights of a company, but does not hold more than 50% of such voting rights and such person, or any person acting in concert with him, acquires an interest in any other shares which increases the percentage of shares carrying voting rights in which he is interested, such person shall, except in limited circumstances, be obliged to extend offers, on the basis set out in Rules 9.3, 9.4 and 9.5 of the City Code, to the holders of any class of equity share capital whether voting or non-voting, and also to the holders of any other class of transferable securities carrying voting rights. Offers for different classes of equity share capital must be comparable.

15.3 Squeeze-out

Under sections 979 to 982 of the Act, if an offeror were to acquire 90% of the issued share capital of a company it could compulsorily acquire the remaining 10% The offeror is required to serve notice on the outstanding shareholders informing them of its intention to compulsorily acquire the shares. No such notice may be served after the end of: (a) the period of three months beginning with the day after the last day on which the offer can be accepted; and (b) if earlier, and the offer is not one to which section 943(1) of the Act applies, the period of six months beginning with the date of the offer.

Six weeks following service of such notice, the offeror must send a copy of it to the Company together with the consideration for the issued share capital to which the notice relates, and an instrument of transfer executed on behalf of the outstanding shareholder(s) by a person authorised by the offeror. The Company will hold the consideration on trust for the outstanding shareholders.

15.4 Sell-out

Sections 983 to 985 of the Act also give minority shareholders in the Company a right to be bought out in circumstances by an offeror which has made a takeover offer. If the takeover offer related to all the issued ordinary shares and at any time before the end of the period within which the offer could be accepted the offeror held or had agreed to acquire not less than 90% of the issued ordinary shares, any holder of issued ordinary shares to which the offer related, who had not accepted the offer, could by written communication to the offeror require it to acquire those shares. The offeror is required to give any shareholder notice of his right to be bought out within one month of that right arising. The offeror may impose a time limit on the rights of minority shareholders to be bought out, but that period cannot end less than three months after the end of the acceptance period or; if longer, a period of three months from the date of the notice. If a shareholder exercises his/her rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

15.5 **Existing or impending takeover bids**

The Company and the Directors are not aware of the existence of any takeover bid pursuant to the rules of the City Code, or any circumstances which may give rise to any takeover bid, and the Company and the Directors are not aware of any public takeover bid by third parties for the Ordinary Shares.

16. Premises

16.1 Serica

The Serica Group occupies the following property:

Property location	Current use	Owned/Leased	Lease End
52 George Street, London W1U 7EA	Head Office	Leased	24 March 2019
21 Gloucester Place, London W1U 8HR	Office Accommodation	Leased	Initial period of 12 months from 11 December 2017

16.2 **BKR Assets**

There are no properties relating to the BKR Assets which will be acquired by the Group pursuant to the Acquisition. However, it is anticipated that prior to Admission, the Group will acquire the right to occupy premises in Aberdeen in Scotland.

17. Employees

17.1 **Serica**

As at the Latest Practicable Date, the Serica Group had 8 employees. The table below sets out the average number of people employed by the Serica Group in the periods indicated:

	Year ended 31 December		
	2016	**2015**	**2014**
Management	3	2	3
Technical	1	2	3
Finance and administration	1	2	4
Total	5	6	10

17.2 **BKR Assets**

As at the Latest Practicable Date, the BKR Assets employed approximately 110 employees who are expected to transfer across to the Group as part of the Acquisition.

18. CREST

The Articles permit the Company to issue shares in uncertificated form in accordance with the CREST Regulations. CREST is a paperless settlement system enabling title to securities to be evidenced otherwise than by certificates and transferred otherwise than by written instrument. Settlement of transactions in Ordinary Shares following Admission may take place within the CREST system if Shareholders so wish. CREST is a voluntary system and Shareholders who wish to receive and retain share certificates will be able to do so upon request from the Registrar.

19. Consents

19.1 Peel Hunt LLP has given and has not withdrawn its written consent to the issue of this document with the inclusion herein of references to its name in the form and context in which it appears.

19.2 Ryder Scott Company, L.P. has given and has not withdrawn its written consent to the inclusion of its report set out in Part V (*Competent Person's Report on the BKR Assets*), and the references thereto and to its name, in the form and context in which they appear and has authorised the contents of those parts of this document. This report was prepared at the request of BP. Ryder Scott Company, L.P. has no interest in the share capital of the Serica Group.

19.3 Netherland, Sewell & Associates, Inc. has given and has not withdrawn its written consent to the inclusion of its report set out in Part VI (*Competent Person's Report on Serica*), and the references thereto and to its name, in the form and context in which they appear and has authorised the contents of those parts of this document. This report was prepared at the request of the Company. Netherland, Sewell & Associates, Inc. has no interest in the share capital of the Serica Group.

20. Miscellaneous

20.1 The total costs and expenses payable by the Company in connection with or incidental to the Proposals, including London Stock Exchange fees, professional fees, consulting and investor relation services and the costs of printing and distribution, are estimated to amount to approximately £1.25 million (excluding VAT).

20.2 The financial information contained in this document does not constitute statutory accounts within the meaning of section 434 of the Act.

20.3 The Ordinary Shares as at the date of this document are in registered form and the Ordinary Shares will, on Admission, be capable of being held in uncertificated form. The Ordinary Shares will be admitted with the ISIN GB00B0CY5V57.

20.4 No public takeover bids have been made by third parties in respect of the Company's issued share capital in the current financial year nor in the last financial year.

20.5 Save as disclosed in this document, the Directors are not aware of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Group's prospects or the BKR Assets for the current financial year.

20.6 Save as disclosed in this document, the Company had no principal investments for each financial year covered by the historical financial information and there are no principal investments in progress and there are no principal future investments on which the Board has made a firm commitment.

20.7 Information sourced from third parties has been accurately reproduced and so far as the Company is aware, and able to ascertain from information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading.

20.8 Save as disclosed in this document, the Directors are not aware of any exceptional factors which have influenced the activities of the Serica Group or the BKR Assets.

20.9 Save as disclosed in this document, there are no patents or other intellectual property rights, licences or particular industrial, commercial or financial contracts or new manufacturing processes which are of fundamental importance to the Enlarged Group's business or profitability.

20.10 Save as disclosed in Part IV (*Risk Factors*), the Directors are not aware of any material environmental issues or risks affecting the utilisation of the Enlarged Group's tangible fixed assets or its operations.

20.11 Save as disclosed in this document, there are no outstanding convertible securities, exchangeable securities or securities with warrants issued by the Company.

21. Documents available for inspection

Copies of the following documents will be available for inspection during normal business hours on any weekday (Saturday, Sundays and public holidays excepted) at the offices of Serica Energy PLC, 52 George Street, London W1U 7EA from the date of this document until at least 30 days after the date of Admission and will be available for viewing on the Company's website at www.serica-energy.com (up to Admission):

(a) the Articles;

(b) the BKR CPR;

(c) the Serica CPR;

(d) the audited consolidated accounts for the Serica Group for the financial years ended 31 December 2016, 31 December 2015 and 31 December 2014;

(e) the unaudited consolidated interim financial statements for the Serica Group for the six months ended 30 June 2017;

(f) the consent letters referred to in paragraph 19 of this Part XII (*Additional Information*);

(g) the service contracts and letters of appointment referred to in paragraph 7 of this Part XII (*Additional Information*);

(h) this document.

22. Documents incorporated by reference

The information incorporated by reference and set out in Part VIII (*Historical Financial Information on Serica*), of this document is available free of charge in electronic format on the Company's website at www.serica-energy.com (up to Admission).

Hard copies of the documents noted in this paragraph 22 of this Part XII (*Additional Information*) as incorporated into this document by reference will not be sent to Shareholders unless requested by them. However, should Shareholders wish to receive hard copies of such documents they should request copies from the Company at 52 George Street, London W1U 7ES or by telephone on +44 (0)20 7487 7300.

Any statement contained in a document which is deemed to be incorporated by reference herein shall be deemed to be modified or superseded for the purpose of this document to the extent that a statement contained herein (or in a later document which is incorporated by reference herein) modifies or supersedes such earlier statement (whether expressly, by implication or otherwise). Any statement so modified or superseded for the purpose of this document shall be deemed, except as so modified or superseded, to constitute a part of this document.

Dated: 30 November 2017

PART XIII – DEFINITIONS

The following definitions apply throughout this document unless the context requires otherwise:

"2005 Plan"	the Serica Energy plc Share Option Plan, adopted by the Board on 14 November 2005;
"2016 CSOP"	the Serica Energy Plc Company Share Option Plan, which was approved by Shareholders on 23 June 2016;
"2017 AGM"	the annual general meeting of the Company held on 29 June 2017;
"2017 CSOP"	the Serica Energy plc 2017 Company Share Option Plan;
"A Share"	the "A" Share of £50,000 in the capital of the Company;
"Acquisition"	the proposed acquisition by Serica UK of the BKR Assets on the terms of the Sale and Purchase Agreement;
"Admission"	the re-admission of the Ordinary Shares to trading on AIM becoming effective in accordance with the AIM Rules following Completion;
"AIM"	AIM, a market of the London Stock Exchange;
"AIM Rules"	the AIM Rules for Companies and the AIM Rules for Nominated Advisers, as applicable;
"AIM Rules for Companies"	the rules for AIM companies published by the London Stock Exchange, as amended or re-issued from time to time;
"AIM Rules for Nominated Advisers"	the rules for nominated advisers to AIM companies published by the London Stock Exchange, as amended or re-issued from time to time;
"Articles"	the articles of association of the Company as at the date of this document, a summary of certain provisions of which is set out in paragraph 5 of Part XII (*Additional Information*);
"BEIS"	the Department for Business, Energy and Industrial Strategy;
"BKR Assets"	BP's interests in the Bruce, Keith and Rhum fields in the North Sea (save for a 1% interest in the Bruce field which is being retained by BP) and as more specifically set out in the Sale and Purchase Agreement and described in this document;
"BKR CPR" or "BKR Competent Person's Report"	the independent technical report of Ryder Scott Company L.P. dated 17 November 2017 which is reproduced in its entirety in Part V (*Competent Person's Report on the BKR Assets*);
"Board"	the board of directors of the Company as constituted from time to time;
"BP"	BP Exploration Operating Company Limited;
"BP Gas"	BP Gas Marketing Limited;
"BP Group"	BP's ultimate parent company, BP p.l.c., and any subsidiary of such parent company;
"BP Oil"	BP Oil International Limited;
"Business Day"	a day (other than Saturday or Sunday) on which banks are generally open for business in London ;
"CAD$" or "Canadian dollar"	the Canadian dollar, the lawful currency from time to time of Canada;
"CATS"	Central Area Transmission System;
"certificated" or "in certificated form"	the description of a share or other security which is not in uncertificated form (that is, not in CREST);
"City Code"	the City Code on Takeovers and Mergers in the United Kingdom;
"Companies Act" or "Act"	the Companies Act 2006, as amended;
"Company" or "Serica"	Serica Energy Plc, a company incorporated in England and Wales with registration number 5450950;

"Completion"	completion of the Acquisition in accordance with the terms of the Acquisition Agreement;
"Corporate Governance Code"	the UK Corporate Governance Code, published by the Financial Reporting Council;
"CREST"	the computerised settlement system, facilitating the paperless settlement of trades and the holding of uncertificated shares administered by Euroclear UK & Ireland Limited, the operator of CREST;
"CREST Regulations"	the Uncertificated Securities Regulations 2001 of the UK (SI 2001/3755) (as amended) ;
"DECC"	the Department of Energy and Climate Change;
"Directors"	the current directors of the Company, whose names are set out on page 4 of this document;
"DTR" or "Disclosure and Transparency Rules"	the disclosure guidance and transparency rules of the UK Listing Authority made pursuant to Part VI of FSMA;
"EIA"	the US Energy Information Administration;
"Enlarged Group"	Serica and its subsidiaries following Completion;
"EY"	Ernst & Young LLP;
"EU"	the European Union;
"Form of Proxy"	the form of proxy accompanying this document for use in respect of the General Meeting;
"FCA"	the United Kingdom Financial Conduct Authority;
"FSMA"	the UK Financial Services and Markets Act 2000 (as amended) including any regulations made pursuant thereto;
"General Meeting"	the general meeting of the Company to be held on 18 December 2017 (and any adjournment thereof) for the purposes of considering the Resolution, notice of which is set out at the end of this document;
"HMRC"	Her Majesty's Revenue and Customs;
"HSE"	the Health and Safety Executive;
"IFRS"	International Financial Reporting Standards as adopted by the European Union;
"Initial Consideration"	the initial cash consideration of £12.8 million payable for the BKR Assets pursuant to the Sale and Purchase Agreement;
"IOC"	Iranian Oil Company (UK) Limited, BP's partner on the Rhum field;
"Introduction Agreement"	the conditional agreement between Peel Hunt, the executive Directors and the Company dated 30 November 2017 described at paragraph 11.1(a) of Part XII (*Additional Information*);
"Latest Practicable Date"	29 November 2017, being the latest practicable date prior to publication of this document;
"Link Asset Services"	a trading name of Link Asset Services Limited;
"London Stock Exchange"	London Stock Exchange plc;
"MAR"	the EU Market Abuse Regulation (No 596/2014);
"Maximising Economic Recovery"	an OGA programme to maximise the recovery of oil and gas on the UKCS;
"Net Cash Flow Sharing Deed"	a deed between BP and Serica UK to be entered into on Completion which sets out the methodology for calculating BP's share of future net cash flows from the BKR Assets as described at paragraph 11.1(e) of Part XII (*Additional Information*);

"NIOC"	National Iranian Oil Company, the parent of IOC, which is BP's partner on the Rhum field;
"Notice"	the notice convening the General Meeting set out at the end of this document;
"OFAC"	US Office of Foreign Asset Control;
"Official List"	the Official List of the UK Listing Authority;
"OGA"	the Oil and Gas Authority;
"Open Permission"	a form of automatic consent from the OGA under the Open Permission (Creation of Security Rights of Licences);
"OPEP Regulations"	the environmental regime applying to oil and gas activities in the UKCS, comprising a large number of statutory instruments. including, but not limited to, the Merchant Shipping (Oil Pollution Preparedness, Response & Cooperation Convention) Regulations 2015, and the Offshore Installations (Emergency Pollution Control) Regulations 2002 (together the OPEP Regulations);
"Ordinary Shares"	the ordinary shares in the capital of Serica of US$0.10 each;
"OSD"	the Offshore Safety Directive;
"OSD Regulations"	the regulations transposing the OSD into UK law by the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) (Amendment) Regulations 2015, and the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015;
"OSDR"	the Offshore Safety Directive Regulator;
"PDA"	Petroleum Development Associates (Oil and Gas) Limited;
"Peel Hunt"	Peel Hunt LLP, nominated adviser and broker to the Company;
"Petroleum Act"	the Petroleum Act 1998 (as amended);
"Prepayment Facility"	the prepayment facility between BP Gas and Serica UK dated 21 November 2017 described at paragraph 11.1(d) of Part XII (*Additional Information*);
"Product Sales Agreements"	those agreements in relation to the sale of gas, oil and NGLs referred to at paragraph 11.1(c) of Part XII (*Additional Information*);
"Proposals"	the proposals set out in this document, including the Acquisition and Admission;
"Prospectus Directive"	Directive 2003/71/EC (and amendments thereto including 2010 PD Amending Directive), including any relevant amending implementing measures in each member state of the European Economic Area that has implemented Directive 2003/71/EC;
"Prospectus Rules"	the rules published by the FCA under FSMA governing the publication of a prospectus, as derived from the Prospectus Directive;
"Resolution"	the resolution set out in the Notice;
"Restricted Jurisdiction"	any non-EEA jurisdiction where local laws or regulations may result in a significant risk of civil, regulatory or criminal sanction if information concerning the Proposals is sent or made available to Shareholders in that jurisdiction;
"Rhum R3 Well"	the third well drilled on the Rhum field which is proposed to be re-entered in 2018;
"Ryder Scott"	Ryder Scott Company L.P., the technical consultants on the BKR Assets;

"Sale and Purchase Agreement" or **"Acquisition Agreement"**	the conditional agreement between Serica UK and BP dated 21 November 2017 in relation to the acquisition of the BKR Assets, described at paragraph 11.1(b) of Part XII (*Additional Information*);
"SDRT"	Stamp Duty Reserve Tax;
"Section 29 Notice"	a notice served under section 29 of the Petroleum Act;
"Security Agreements"	the security agreements to be entered into on Completion between, among others, Serica UK and BP and the deed of guarantee dated 21 November 2017 between Serica, BP and BP Gas, pursuant to which security will be granted to BP on Completion, to secure, *inter alia*, its rights to the net cash flow from future operations of the BKR Assets as described at paragraph 11.1(f) of Part XII (*Additional Information*);
"Serica CPR" or "Serica Competent Person's Report"	the independent technical report of Netherland, Sewell & Associates, Inc., dated 20 November 2017, which is reproduced in its entirety in Part VI (*Competent Person's Report on Serica*);
"Serica Group" or **"Group"**	the Company and its subsidiaries as at the date of this document;
"Serica Namibia"	Serica Energy Namibia B.V., a wholly owned subsidiary of the Company;
"Serica Rockall"	Serica Energy Rockall B.V., a wholly owned subsidiary of the Company;
"Serica Slyne"	Serica Energy Slyne B.V., a wholly owned subsidiary of the Company;
"Serica UK"	Serica Energy (UK) Limited, a wholly owned subsidiary of the Company;
"Share Dealing Code"	the Company's Code for dealing by Directors and employees in the Company's Ordinary Shares;
"Shareholders" or "Serica Shareholders"	holders of Ordinary Shares from time to time;
"Transfer of Operatorship Agreement"	the agreement between BP and Serica UK dated 21 November 2017 relating to the transfer of operatorship of the BKR Assets to Serica described at paragraph 11.1(g) of Part XII (*Additional Information*);
"TUPE"	the Transfer of Undertakings (Protection of Employment) Regulations 2006;
"TSX"	Toronto Stock Exchange;
"UKCS"	the UK Continental Shelf;
"UK Listing Authority"	the FCA acting in its capacity as the competent authority for the purposes of Part VI of FSMA;
"uncertificated" or "uncertificated form"	recorded on the relevant register of the share or security concerned as being held in uncertificated form in CREST and title to which may be transferred by means of CREST
"United Kingdom" or "UK"	the United Kingdom of Great Britain and Northern Ireland
"United States", "United States of America" or "US"	the United States of America, its territories and possessions, any state of the United States of America and the District of Columbia and all other areas subject to its jurisdiction;
"US Securities Act"	the United States Securities Acts of 1933, as amended, and the rules and regulations promulgated thereunder;
"US$" or "US dollar"	the US dollar, the lawful currency from time to time of the United States;
"Wood Review"	the review requested in June 2013 by the Secretary of State for Energy and Climate Change and undertaken by Sir Ian Wood concerning the challenges faced by the offshore upstream industry; and
"£" or "Sterling"	pounds sterling, the lawful currency from time to time of the United Kingdom.

PART XIV – GLOSSARY OF TECHNICAL TERMS

The following glossary of technical terms applies throughout this document unless the context requires otherwise:

Term	Meaning
"1P"	proved reserves;
"2C"	the best estimate of contingent resources;
"2P"	proved plus probable reserves;
"3P"	proved plus probable plus possible reserves;
"bbl"	barrel of 42 US gallons;
"bcf"	billion standard cubic feet;
"boe"	barrel of oil equivalent;
"boepd"	barrels of oil equivalent per day;
"contingent resources"	contingent resources are those quantities of petroleum which are estimated to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies;
"LNG"	liquefied natural gas;
"MBtu"	million British thermal units;
"mbbl"	thousand barrels of oil;
"mboe"	thousand barrels of oil equivalent;
"mmbbl"	million barrels of oil;
"mmboe"	million barrels of oil equivalent;
"mmcf"	million of cubic feet;
"mmscf"	million standard cubic feet;
"mmscfd"	million standard cubic feet per day;
"NGLs"	natural gas liquids extracted from gas streams;
"P10" or **"High Estimate"**	the high estimate of prospective resources;
"P50" or **"Best Estimate"**	the best estimate of prospective resources;
"P90" or **"Low Estimate"**	the low estimate of prospective resources;
"possible reserves"	possible reserves are those additional Reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved + probable + possible reserves;
"PRMS"	the Society of Petroleum Engineers/World Petroleum Council/ American Association of Petroleum Geologists/Society of Petroleum Evaluation Engineers Petroleum Resources Management System;
"probable reserves"	probable reserves are those additional Reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved + probable reserves;
"prospective resources"	prospective resources are those quantities of petroleum which are estimated to be potentially recoverable from undiscovered accumulations by application of future projects. Prospective resources have both an associated chance of discovery and a chance of development;
"proved reserves"	proved reserves are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves;
"p/th"	pence/therm;

"Reserves"	estimates of discovered recoverable commercial hydrocarbon reserves;
"tcf"	trillion standard cubic feet; and
"WTI"	West Texas intermediate crude oil.

NOTICE OF GENERAL MEETING

Serica Energy plc

(“Company”)

(Incorporated and registered in England and Wales under the Companies Act 1985 with registered number 05450950)

NOTICE IS HEREBY GIVEN that a general meeting of the Company will be held on 18 December 2017 (the “**Meeting**”) at 11.00 a.m. at the offices of Ashurst LLP, Broadwalk House, 5 Appold Street, London EC2A 2HA for the purpose of considering and, if thought fit, passing the following resolution, which will be proposed as an ordinary resolution:

ORDINARY RESOLUTION

1. **THAT** the proposed acquisition of the BKR Assets (as that term is defined in the Admission Document of the Company dated 30 November 2017 (“**Admission Document**”)) on the terms and conditions set out in the sale and purchase agreement as summarised in the Admission Document of which this notice forms part (“**Acquisition**”) be and is hereby approved for the purposes of Rule 14 of the AIM Rules for Companies published by London Stock Exchange plc and the board of directors of the Company (or a duly constituted committee of the board), be and is hereby authorised to waive, amend, vary or extend any of the conditions and terms of the Acquisition and to do all such things as it may consider necessary or desirable to complete the Acquisition.

By order of the Board

Amanda Bateman
Secretary

30 November 2017

Registered Office

Serica Energy plc
52 George Street
London
WlU 7EA

NOTES

1. Pursuant to regulation 41 of the Uncertificated Securities Regulations 2001, the Company specifies that in order to have the right to attend and vote at the General Meeting (and also for the purpose of determining how many votes a person entitled to attend and vote may cast), a person must be entered on the register of members of the Company no later than close of business on the day that is two days before the time for holding the meeting or any adjournment of it. Changes to entries on the register of members after this time shall be disregarded in determining the rights of any person to attend or vote at the meeting.
2. Only holders of Ordinary Shares are entitled to attend and vote at this meeting.
3. A member is entitled to appoint another person as his proxy to exercise all or any of his rights to attend, to speak and to vote at the General Meeting. A member may appoint more than one proxy in relation to the meeting, provide that each proxy is appointed to exercise the rights attached to a different share or shares held by him. A proxy need not be a member of the Company. A form of proxy for the meeting is enclosed.
4. To be valid any proxy form or other instrument appointing a proxy must be received by post or by hand (during normal business hours only) by our registrar, Link Asset Services, PXS 1, The Registry, 34 Beckenham Road, Kent BR3 4ZF, or electronically using the Share Portal Service at www.signalshares.com no later than 48 hours before the time for the holding of the meeting or any adjournment of it. If you are a CREST member, see note 5 below.

   Completion of a form of proxy, or other instrument appointing a proxy or any CREST Proxy Instruction will not preclude a member attending and voting in person at the meeting if he/she wishes to do so.
5. Alternatively, if you are a member of CREST, you may register the appointment of a proxy by using the CREST electronic proxy appointment service. Further details are contained below.

   CREST members who wish to appoint a proxy or proxies through the CREST electronic proxy appointment service may do so for the General Meeting and any adjournment(s) thereof by using the procedures, and to the address, described in the CREST Manual (available via www.euroclear.com/CREST) subject to the provisions of the Company's articles of association. CREST personal members or other CREST sponsored members, and those CREST members who have appointed a voting service provider(s), should refer to their CREST sponsor or voting service provider(s), who will be able to take the appropriate action on their behalf.

   In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST message (a "**CREST Proxy Instruction**") must be properly authenticated in accordance with Euroclear UK and Ireland Limited's ("**Euroclear**") specifications and must contain the information required for such instructions, as described in the CREST Manual. The message, regardless of whether it constitutes the appointment of a proxy or an amendment to the instruction given to a previously appointed proxy, must, in order to be valid, be transmitted so as to be received by the issuer's agent (ID: RA10) by the latest time(s) for receipt of proxy appointments specified in the notice of the General Meeting. For this purpose, the time of receipt will be taken to be the time (as determined by the time stamp applied to the message by the CREST Applications Host) from which the issuer's agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

   CREST members and, where applicable, their CREST sponsors or voting service provider(s) should note that Euroclear does not make available special procedures in CREST for any particular messages. Normal system timings and limitations will therefore apply in relation to the input of CREST Proxy Instructions. It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member or sponsored member or has appointed a voting service provider(s), to procure that his CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting service provider(s) are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

   The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Uncertificated Securities Regulations 2001.
6. Any corporation which is a member can appoint one or more corporate representatives who may exercise on its behalf all of its powers as a member provided that they do not do so in relation to the same shares.
7. Any member attend the General Meeting has the right to ask questions. The Company must cause to be answered any such question relating to the business being dealt with at the meeting but no such answer need be given if (a) to do so would interfere unduly with the preparation of the meeting or involve the disclosure of confidential information, (b) the answer has already been given on a website in the form of an answer to a question, or (c) it is undesirable in the interests of the Company or the good order of the meeting that the question be answered.
8. You may not use any electronic address (within the meaning of section 333(4) of the Companies Act 2006 provided in this Notice of Meeting (or in any related documents including the proxy form) to communicate with the Company for any purposes other than those expressly stated.