SAVANNAH PETROLEUM



SAVANNAH PETROLEUM PLC

ADMISSION DOCUMENT

DECEMBER 2017

THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. If you are in any doubt about the contents of this document or as to what action you should take, you should seek your own personal advice immediately from your stockbroker, bank manager, solicitor, accountant or other independent financial adviser who specialises in advising on the acquisition of shares and other securities and is authorised under the Financial Services and Markets Act 2000 (as amended) ("FSMA") if you are resident in the UK, or, if you are not resident in the UK, from another authorised independent adviser.

This document does not comprise a prospectus within the meaning of section 85 of FSMA and does not constitute an offer of transferable securities to the public in the United Kingdom, within the meaning of section 102B of FSMA, and has not been approved or examined by and will not be filed with the United Kingdom Financial Conduct Authority, London Stock Exchange plc (the "**London Stock Exchange**") or the United Kingdom Listing Authority ("**UKLA**"), but comprises an admission document in relation to AIM, a market operated by the London Stock Exchange ("**AIM**"). It has been drawn up in accordance with the AIM Rules (as defined below) and has been issued in connection with the proposed re-admission to trading of the Further Enlarged Share Capital (as defined below) on AIM ("**Re-Admission**").

Savannah Petroleum PLC (the "**Company**") and its directors (together, the "**Directors**"), whose names appear on page 8 of this document, accept responsibility, collectively and individually, for the information contained in this document and for compliance with the AIM Rules for Companies (the "**AIM Rules**"). To the best of the knowledge and belief of the Company and the Directors, who have taken all reasonable care to ensure that such is the case, the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information. To the extent that information has been sourced from a third party, this information has been accurately reproduced and, as far as the Directors are aware, no facts have been omitted which may render the reproduced information inaccurate or misleading. In connection with this document, no person is authorised to give any information or make any representation other than as set out in this document.

In accordance with the AIM Rules, application will be made in time for Re-Admission of the whole of the Company's issued ordinary shares (the "**Existing Ordinary Shares**"), the Company's new ordinary shares being placed (the "**Placing Shares**") and the Company's new ordinary shares being issued in consideration for part of the Acquisition (the "**Consideration Shares**") (together the "**Further Enlarged Share Capital**"). It is expected that Re-Admission will become effective and dealings in the Further Enlarged Share Capital will commence on AIM by the end of March 2018. The Further Enlarged Share Capital is not dealt in on any market other than, from Re-Admission, AIM and, apart from the application for Re-Admission, no application has been or is intended to be made for the Further Enlarged Share Capital to be admitted to trading on any such other market. No application has been or is intended to be made for the Warrants to be admitted to trading on AIM or any other market.

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 UKLA (the "Official List") and the AIM Rules are less demanding than those regulations applicable to companies on the Official List. It is emphasised that no application is being made for admission of the Further Enlarged Share Capital to trading on the Official List. A prospective investor should be aware of the risks of investing in AIM companies and should make the decision to invest only after careful consideration and, if appropriate, consultation with an independent financial adviser.

Each AIM company is required pursuant to the AIM Rules to have a nominated adviser. The nominated adviser is required to make a declaration to the London Stock Exchange on Re-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.

THE WHOLE OF THE TEXT OF THIS DOCUMENT SHOULD BE READ AND IN PARTICULAR YOUR ATTENTION IS DRAWN TO THE SECTION ENTITLED "RISK FACTORS" SET OUT IN PART 3 OF THIS DOCUMENT THAT DESCRIBES CERTAIN RISKS ASSOCIATED WITH AN INVESTMENT IN THE COMPANY.

SAVANNAH PETROLEUM PLC

(incorporated in England & Wales under the Company's Act 2006 with registered number 09115262)

PROPOSED ACQUISITION OF CERTAIN OF SEVEN ENERGY'S NIGERIAN ASSETS, FIRM AND CONDITIONAL PLACING OF 266,462,000 NEW ORDINARY SHARES AT 35 PENCE PER SHARE, ISSUE OF ONE WARRANT FOR EVERY TWO PLACING SHARES, NOTICE OF GENERAL MEETING, PROPOSED ISSUANCE OF 312,013,810 NEW ORDINARY SHARES AT 35 PENCE PER SHARE TO CERTAIN OF SEVEN ENERGY'S CREDITORS, AND RE-ADMISSION OF THE FURTHER ENLARGED SHARE CAPITAL TO TRADING ON AIM FOLLOWING SATISFACTION OF CONDITIONS PRECEDENT

Financial & Nominated Adviser
Strand Hanson Limited

Global Co-ordinator & Joint Bookrunner
Barclays Bank PLC

Joint Bookrunner & Joint Broker
Mirabaud Securities Limited

Lead Manager
Shore Capital Stockbrokers Limited

Financial Adviser and Joint Broker
Hannam & Partners (Advisory) LLP

The Placing of the First Tranche Placing Shares and the Placing of the Second Tranche Placing Shares and the grant of the Warrants are conditional on, *inter alia*, admission of the First Tranche Placing Shares taking place on or before 28 December 2017 and admission of the Second Tranche Placing Shares taking place shortly after completion of either the Exchange Offer or the receipt of the Scheme

Approvals, respectively, (or such later dates as the Company, Strand Hanson Limited ("**Strand Hanson**") and Barclays Bank PLC (acting through its investment bank) ("**Barclays**") may agree), but in any event not later than 30 April 2018. The Placing of the First Tranche Placing Shares is not conditional on the Placing of the Second Tranche Placing Shares. The Placing Shares will, when admitted, rank in full for all dividends or other distributions hereafter declared, made or paid and will rank *pari passu* in all other respects with the Existing Ordinary Shares.

Strand Hanson, which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as financial and nominated adviser to the Company in connection with the Placing and the proposed First Admission, Second Admission and Re-Admission. Its responsibility as the Company's nominated adviser under the AIM Rules for Nominated Advisers is owed solely to the London Stock Exchange and is not owed to the Company or to any Director or to any other person in respect of their decision to acquire shares in the Company in reliance on any part of this document. Strand Hanson is acting exclusively for the Company and for no one else and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice in relation to the contents of this document or the Placing or the proposed First Admission, Second Admission and Re-Admission.

Barclays, which is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority in the United Kingdom, is acting exclusively for the Company and no one else in connection with the Placing and the proposed First Admission, Second Admission and Re-Admission and will not regard any other person (whether or not a recipient of this document) as a client in relation to the Placing, First Admission and Second Admission and will not be responsible to anyone other than the Company for providing the protections afforded to its clients nor for giving advice in relation to the Placing or First Admission, Second Admission and Re-Admission or any transaction, arrangement or matter referred to in this document.

Mirabaud Securities Limited ("**Mirabaud**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Joint Bookrunner and Joint Broker to the Company in connection with the Placing and the proposed First Admission, Second Admission and Re-Admission. Mirabaud is acting exclusively for the Company and for no one else and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice in relation to the contents of this document or the Placing or the proposed First Admission, Second Admission and Re-Admission.

Shore Capital Stockbrokers Limited ("**Shore Capital**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Lead Manager to the Company in connection with the Placing and the proposed First Admission, Second Admission and Re-Admission. Shore Capital is acting exclusively for the Company and for no one else and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice in relation to the contents of this document or the Placing or the proposed First Admission, Second Admission and Re-Admission.

Hannam & Partners (Advisory) LLP ("**Hannam & Partners**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Financial Adviser and Joint Broker to the Company in connection with the Placing and the proposed First Admission, Second Admission and Re-Admission. Hannam & Partners is acting exclusively for the Company and for no one else and will not be responsible to anyone other than the Company for providing the protections afforded to its clients or for providing advice in relation to the contents of this document or the Placing or the proposed First Admission, Second Admission and Re-Admission.

None of Strand Hanson, Barclays, Mirabaud, Shore Capital or Hannam & Partners have authorised the contents of this document and no representation or warranty, express or implied, is made by any of Strand Hanson, Mirabaud, Barclays, Shore Capital or Hannam & Partners as to the accuracy or contents of this document or the opinions contained herein, without limiting the statutory rights of any person to whom this document is issued. The information contained in this document is not intended to inform or be relied upon by any subsequent purchasers of any ordinary shares in the capital of the Company ("**Ordinary Shares**") (whether on or off exchange) and accordingly no duty of care is accepted by Strand Hanson, Barclays, Mirabaud, Shore Capital or Hannam & Partners in relation to them. 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 so authorised. The delivery of this document will not, under any circumstances, be deemed to 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 at any time subsequent to its date.

No legal, business, tax or other advice is provided in this document. Prospective investors should consult their professional advisers as needed on the potential consequences of subscribing for, purchasing, holding or selling Ordinary Shares and Warrants under the laws of their country and/or state of citizenship, domicile or residence.

This document does not constitute an offer to sell, or a solicitation to buy, Ordinary Shares or Warrants in any jurisdiction in which such offer or solicitation is unlawful. 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 such restrictions. Any such distribution could result in a violation of the laws of such jurisdictions. In particular, subject to certain exceptions, this document is not for distribution into the United States of America ("**United States**"), Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan, or any other jurisdiction where to do so would be in breach of any applicable laws and/or regulations. The Ordinary Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants have not been, nor will they be, registered under the securities legislation of the United States, any province or territory of Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan. Accordingly, the Ordinary Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants may not, subject to certain exemptions, be offered, sold, re-sold, renounced, taken up or delivered, directly or indirectly, into the United States, Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan, or to any national, citizen or resident of Canada, Australia, the Republic of South Africa, the Republic of Ireland or Japan. No action has been taken by the Company, the holders of Ordinary Shares, or by Strand Hanson, Barclays or Mirabaud that would permit a public offer of Ordinary Shares or possession or distribution of this document where action for that purpose is required.

Investors should only rely on the information in this document and any supplementary Admission Document produced to supplement the information contained in this document. No person has been authorised to give any information or to make any representations other than as contained in this document in connection with the Placing and, if given or made, such information and representations must not be relied upon as having been authorised by or on behalf of the Company, Barclays or Mirabaud. The contents of the websites of the Group (and/or any of its affiliates) or any website directly or indirectly linked to such websites do not form part of this document and investors should not rely on them.

Copies of this document and any supplementary Admission Document will be available free of charge during normal business hours on weekdays (excluding Saturdays, Sundays and public holidays) from the date hereof until one month after Re-Admission from the offices of Strand Hanson Limited at 26 Mount Row, London W1K 3SQ and from the Company's website: http://www.savannah-petroleum.com.

Notice to prospective overseas investors

European Economic Area

This document and the offer when made is only addressed to and directed at persons in member states of the European Economic Area who are "qualified investors" within the meaning of Article 2(1)(e) of the Prospectus Directive (Directive 2003/71/EC) ("**Qualified Investors**"). In addition, in the United Kingdom, this document is being distributed only to, and is directed only at, Qualified Investors: (i) who have professional experience in matters relating to investments falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the "**Order'**'), and Qualified Investors falling within Article 49(2)(a) to (d) of the Order; and (ii) to whom it may otherwise lawfully be communicated (all such persons together being referred to as "**relevant persons**"). This document must not be acted on or relied on: (i) in the United Kingdom, by persons who are not relevant persons; and (ii) in any member state of the European Economic Area other than the United Kingdom, by persons who are not Qualified Investors. Any investment or investment activity to which this document relates is available only to: (i) in the United Kingdom, relevant persons; and (ii) in any member state of the European Economic Area other than the United Kingdom, Qualified Investors.

United States

The Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants contemplated in this Admission Document have not been, and will not be, registered under the US Securities Act of 1933, as amended (the "US Securities Act"), or with any securities regulatory authority of any state or other jurisdiction of the United States and, subject to certain exceptions, may be offered only outside the United States in offshore transactions in reliance upon Regulation S under the US Securities Act. There will be no public offer of the Placing Shares or Warrants or shares underlying the Warrants in the United States.

THE ORDINARY SHARES AND WARRANTS HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE US SECURITIES AND EXCHANGE COMMISSION, ANY OTHER FEDERAL OR STATE SECURITIES COMMISSION IN THE UNITED STATES OR ANY OTHER REGULATORY AUTHORITY IN THE UNITED STATES, AND NO SUCH AUTHORITIES HAVE PASSED UPON OR ENDORSED THE MERITS OF THE PLACING OR CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENCE IN THE UNITED STATES.

Australia

This document is not a prospectus, product disclosure document or other type of disclosure document required to be lodged with the Australian Securities and Investments Commission ("ASIC") under Chapter 6D or Chapter 7 of the Australian Corporations Act 2001 (Cth) ("Corporations Act") and it has not been, and will not be, lodged with ASIC. Accordingly, this document does not contain the information which would be contained in a prospectus, product disclosure document or other type of disclosure document prepared under the Corporations Act, and does not purport to contain all of the information that may be necessary or desirable to enable a potential investor to properly evaluate and consider an investment in the securities proposed to be offered under the Placing.

The offer of securities under the Placing to investors in Australia will only be made to the extent that such offers of securities for issue do not need disclosure to investors under Part 6D.2 or Chapter 7 of the Corporations Act. In particular, any person who receives an offer of securities under the Placing in Australia represents and warrants to the Company that they are a person who falls within an exemption from disclosure to investors in Australia under the Corporations Act, including a "sophisticated investor" within the meaning of section 708(8) of the Corporations Act or a "professional investor" within the meaning of section 708(11) of the Corporations Act, or a "wholesale client" within the meaning of section 761G of the Corporations Act. Any offer of securities received in Australia is void to the extent that it needs disclosure to investors under the Corporations Act.

South Africa

The offer of securities and Warrants under the Placing is not an offer to the public for purposes of the South African Companies Act, 2008, and this document is not a prospectus required to be filed with the South African Companies and Intellectual Property Commission in terms of the Companies Act. Any person who receives an offer of securities under the Placing in South Africa represents and warrants to the Company that they are a person falling within a category of person listed in section 96 of the Companies Act as not being members of the public.

For the avoidance of doubt, Barclays is not procuring Placees in South Africa or otherwise participating in the marketing or distribution of the Placing Shares or Warrants in South Africa.

Switzerland

This document is being distributed in Switzerland to a small number of selected investors only. Each copy of this document so distributed is addressed to a specifically named recipient and must not be passed on to third parties. The Placing Shares and Warrants are not to be offered to the public in Switzerland, and neither this document nor any other offering materials relating to the Placing Shares or Warrants may be distributed in connection with such offer.

Forward-looking statements

This document contains forward looking statements relating to the Company's future prospects, developments and strategies, which have been made after due and careful enquiry and are based on the Directors' current expectations and assumptions and involve known and unknown risks and uncertainties that could cause actual results, performance or events to differ materially from those expressed or implied in such statements. Forward-looking statements are or may be, without limitation, identified by the use of terms and phrases such as "believe", "could", "envisage", "estimate", "intend", "may", "plan", "will" or the negative of those, variations or comparable expressions, including references to assumptions. These forward-looking statements are subject to, *inter alia*, the risk factors described in Part 3 of this document. The Directors believe that the expectations reflected in these statements are reasonable, but may be affected by a number of variables which could cause actual results or trends to differ materially. Each forward-looking statement speaks only as of the date of the particular statement.

CONTENTS

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Publication of this document	22 December 2017
Restoration to trading on AIM of the Existing Ordinary Shares	22 December 2017
First Tranche Placing Shares admitted to trading on AIM	8.00 a.m. on 28 December 2017
CREST accounts expected to be credited in respect of First Tranche Placing Shares	28 December 2017
Definitive share certificates expected to be despatched in respect of the First Tranche Placing Shares (where applicable)	By 5 January2018
Latest time and date for receipt of Forms of Proxy	3.00 p.m. on 6 January 2018
Expected General Meeting date	3.00 p.m. on 8 January 2018
Second Tranche Placing Shares and Consideration Shares admitted to trading on AIM and Warrants issued(3)	Early February 2018
CREST accounts expected to be credited in respect of Second Tranche Placing Shares and Consideration Shares (where applicable)(3)	Early February 2018
Definitive certificates expected to be despatched in respect of the Second Tranche Placing Shares and Consideration Shares (where applicable) and the Warrants(3)	Mid February 2018
Ministerial Consent and NSEC Consent received(1)	By mid March 2018
Completion of the Transaction(1)(2)(3)	By end of March 2018
Publication of supplemental Admission Document and Re-Admission becomes effective and dealings in the Further Enlarged Share Capital expected to commence on AIM(1)(2)(3)	By end of March 2018

(1) Indicative dates based on the Directors best estimate of when these events will occur, and therefore there is no certainty these dates will not change.

(2) Completion involves, *inter alia*, entering into the Implementation Agreement which sets out the sequence of events pursuant to which the Transaction will complete, such sequence being commenced upon satisfaction of any conditions precedent to the Implementation Agreement.

(3) On assumption that acquisition of SSNs effected through an Exchange Offer. In the event the Company relies on a Scheme of Arrangement to obtain the Scheme Approvals, this will be a later date. The Exchange Offer is currently expected to commence in early January and will remain open for a period of not less than 20 business days. The Scheme of Arrangement (if required) would currently be expected to complete in April 2018.

Each of the times and dates in the above timetable is subject to change without further notice. All references are to London time unless otherwise stated. Temporary documents of title will not be issued.

PLACING STATISTICS

Number of Existing Ordinary Shares in issue at the date of this document	274,621,447
Placing Price and Conversion Price	35 pence
Number of First Tranche Placing Shares	27,462,000
Gross proceeds from the issue of the First Tranche Placing Shares	US$12.9 million
Initial Enlarged Share Capital	302,083,447
Market capitalisation on First Admission at the Placing Price	US$141.7 million
Number of Second Tranche Placing Shares	239,000,000
Aggregate number of Warrants in issue immediately following the issue of the Second Tranche Placing Shares	133,231,000
Gross proceeds from the issue of the Second Tranche Placing Shares	US$112.1 million
Aggregate number of Placing Shares issued	266,462,000
Aggregate gross proceeds from the issue of the Placing Shares	US$125.0 million
Maximum number of Ordinary Shares issuable by exercise of Warrants as a percentage of the Further Enlarged Share Capital	14.9 per cent.
Number of Consideration Shares to be issued	312,013,810
Ordinary Shares subscribed for by the EBT	42,624,837
Further Enlarged Share Capital	895,722,095
Market capitalisation on Second Admission (and Re-Admission assuming no further new Ordinary Shares are issued) at the Placing Price	US$420.3 million
Percentage of the Further Enlarged Share Capital represented by the Placing Shares	29.7 per cent.
Percentage of the Further Enlarged Share Capital represented by the Consideration Shares (assuming no further new Ordinary Shares are issued)	34.8 per cent.
Percentage of the Further Enlarged Share Capital held by the Directors at Second Admission (and Re-Admission assuming no further new Ordinary Shares are issued)	3.4 per cent.
Shares in public hands at Second Admission (and Re-Admission assuming no further new Ordinary Shares are issued)	46.2 per cent.
Share Options currently outstanding pursuant to the Supplementary Plan	10,654,914
Share options over shares in SP1L issued pursuant to the LTIP	15,737,896

EXCHANGE RATES

For reference purposes only, the following exchange rates have been prevailing over the last five years up to 7 December 2017:

GBP/USD	**L5Y**	**L6M**	**L1M**
Average	1.48	1.31	1.33
High	1.72	1.36	1.35
Low	1.20	1.26	1.31
End (07.12.2017)	1.35	1.35	1.35

NGN/USD	**L5Y**	**L6M**	**L1M**
Average	219.80	347.90	359.08
High	367.50	367.50	360.49
Low	156.10	310.50	354.69
End (07.12.2017)	359.99	359.99	359.99

XOF/USD	**L5Y**	**L6M**	**L1M**
Average	553.77	570.14	569.99
High	634.57	591.97	580.37
Low	471.17	547.82	558.29
End (07.12.2017)	580.37	580.37	580.37

Source: Bloomberg using tickers ‘GBP Curncy’, ‘NGN Curncy’ and ‘XOF Curncy’

All amounts expressed throughout this document in the above currencies have, unless otherwise stated, been calculated using the above exchange rates from 7 December 2017.

DIRECTORS, SECRETARY AND ADVISERS

Directors	Steve Jenkins – *Non-Executive Chairman* Sir Stephen O'Brien – *Non-Executive Vice Chairman* Andrew Knott – *Chief Executive Officer* Isatou Semega-Janneh – *Chief Financial Officer* Mark Iannotti – *Non-Executive Director* David Jamison – *Non-Executive Director* David Clarkson – *Non-Executive Director* Michael Watchel – *Non-Executive Director*
Company secretary	Link Company Matters Limited 6th Floor 65 Gresham Street London EC2V 7NQ
Company's registered office	40 Bank Street London E14 5NR
Company's registered number	09115262
Financial & Nominated Adviser	Strand Hanson Limited 26 Mount Row London W1K 3SQ
Financial Adviser and Joint Broker	Hannam & Partners (Advisory) LLP 2 Park Street London W1K 2HX
Global Co-ordinator and Joint Bookrunner	Barclays Bank PLC 5 The North Colonnade Canary Wharf London E14 4BB
Joint Bookrunner and Joint Broker	Mirabaud Securities Limited 10 Bressenden Place London SW1E 5DH
Lead Manager	Shore Capital Stockbrokers Limited Bond Street House 14 Clifford Street London W1S 4JU
Solicitors to the Company as to UK and US law	Burness Paull LLP 50 Lothian Road Festival Square Edinburgh EH3 9WJ Latham & Watkins LLP 99 Bishopsgate London EC2M 3XF Clyde & Co LLP The St Botolph Building 138 Houndsditch London EC3A 7AR

Solicitors to the Company as to Nigerien law	EY Cameroon 1602 Bd de La Liberté Akwa Douala Cameroon
Solicitors to the Company as to Nigerian law	The Law Crest LLP 4B Lalupon Close, Off Keffi Street, Off Awolowo Road, South-West Ikoyi, Lagos. P. O. Box 53514, Ikoyi Lagos State, Nigeria Templars (Barristers and Solicitors) The Octagon (5th Floor) 13A, A.J. Marihno Drive Victoria Island Annexe P.O. Box 72252 Victoria Island Lagos, Nigeria
Solicitors to Barclays	Ashurst LLP Broadwalk House 5 Appold Street London EC2A 2HA
Solicitors to Strand Hanson, Mirabaud and Shore Capital	FieldFisher LLP Riverbank House 2 Swan Lane London EC4R 3TT
Reporting Accountants to the Company	KPMG LLP 15 Canada Square London E14 5GL
Financial PR	Celicourt Communications Limited 7 – 10 Adam Street London WC1N 6AA
Registrar	Computershare Investor Services plc The Pavilions Bridgwater Road Bristol BS13 8AE
Auditors	Grant Thornton (UK) LLP 110 Queen Street Glasgow G1 3BX
Company's website	http://www.savannah-petroleum.com

PART 1

LETTER FROM THE NON-EXECUTIVE CHAIRMAN OF SAVANNAH

SAVANNAH PETROLEUM PLC

(Incorporated and registered in England and Wales under the Companies Act 2006 with registered number 09115262)

Directors:

Steve Jenkins *(Non-Executive Chairman)*
Sir Stephen O'Brien *(Non-Executive Vice Chairman)*
Andrew Knott *(Chief Executive Officer)*
Isatou Semega-Janneh *(Chief Financial Officer)*
Mark Iannotti *(Non-Executive Director)*
David Jamison *(Non-Executive Director)*
David Clarkson *(Non-Executive Director)*
Michael Wachtel *(Non-Executive Director)*

Registered address:

40 Bank Street
London E14 5NR

22 December 2017

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

Dear Shareholder,

PROPOSED ACQUISITION OF CERTAIN OF SEVEN ENERGY'S NIGERIAN ASSETS, CONDITIONAL PLACING OF 266,462,000 NEW ORDINARY SHARES AT 35 PENCE PER SHARE, ISSUE OF ONE WARRANT FOR EVERY TWO PLACING SHARES, NOTICE OF GENERAL MEETING, PROPOSED ISSUANCE OF 312,013,810 NEW ORDINARY SHARES AT 35 PENCE PER SHARE TO CERTAIN OF SEVEN ENERGY'S CREDITORS, AND RE-ADMISSION OF THE FURTHER ENLARGED SHARE CAPITAL TO TRADING ON AIM FOLLOWING SATISFACTION OF CONDITIONS PRECEDENT

1. Introduction

The Company has announced, conditional on, *inter alia*, Shareholder approval at the General Meeting, the Implementation Agreement being entered into, the Accugas Transaction becoming effective, the Frontier Agreements being entered into and becoming effective, the earlier of acceptance of the Exchange Offer by the SSNs or approval of the Seven Energy Court Resolutions at the Seven Energy Court Meetings, Scheme Approvals (if required), Ministerial Consent and NSEC Consent, the acquisition of the Seven Assets from Seven and the Seven Energy Creditor Group for a total consideration of approximately US$280 million, of which approximately US$50 million is to be settled in cash and approximately US$145 million to be settled through the issue of the Consideration Shares. The Enlarged Group is also assuming US$85 million in debt, which is associated with the assets being acquired, as part of the Acquisition.

Certain holders of the outstanding SSNs, the holder of the 10.50 per cent. Notes, the lenders under the First Bilateral Facility and the lenders under the Second Bilateral Facility have entered into the Lock-up Agreement and are expected to enter into the Implementation Agreement (other than SSN holders holding less than four per cent. of the principal amount of the SSNs). Those parties who have entered into the Lock-Up Agreement have agreed to use reasonable endeavours to support, facilitate and implement the Transaction as set out therein, including exercising any voting powers or rights available to such holders in favour of the Transaction. This includes, where applicable, support for the Exchange Offer which will require at least 90 per cent. of the outstanding principal amount of the SSNs to accept the offer and/or support for the schemes of arrangement which require, amongst other things, a majority in number representing at least 75 per cent. in value of the creditors present and voting either in person or by proxy at the creditors' meeting in order to become effective (see paragraph 6 of Part 2 for further details regarding the scheme of arrangement process).

In addition to the conditions mentioned above, the implementation of the Transaction also requires the cooperation of certain other creditors of the Seven Group. With regards to the Accugas IV Facility Agreement, the WCF Agreement, the DSA Facility Agreement and the Promissory Note, Savannah and the respective creditors are at an advanced stage of negotiations to agree non-binding term sheets; however, formal approvals are still outstanding.

The Transaction remains subject to the parties agreeing and entering into definitive documentation.

Savannah is acquiring the following assets from Seven Energy:

- a 40 per cent. participating interest (economic interest detailed below) in the Uquo Field, through the acquisition of SUGL;
- a 62.5 per cent. equity interest in Universal, which holds a 51 per cent. participating interest in the Stubb Creek Field; and
- a 20 per cent. carried interest in Accugas, which owns a 200 MMscfpd gas processing facility as well as a circa 260 km gas pipeline network and associated gas processing infrastructure, in conjunction with a private equity investor, AIIM, which, together with potentially one or more co-investors, will acquire the remaining 80 per cent., concurrently with the completion of the Acquisition.

Due to its size and nature, the Acquisition constitutes a reverse takeover of the Company pursuant to the AIM Rules for Companies. In conjunction with the Acquisition, the Company has announced today that it has: (i) conditionally only on First Admission raised from new and existing investors approximately US$12.9 million (before expenses) via the issue of the First Tranche Placing Shares; and (ii) raised from new and existing investors, conditional on the passing of the Resolutions 2 and 3 and acceptance of the Exchange Offer by the SSNs or receipt of the Scheme Approvals, approximately US$112.1 million (before expenses) via the issue of the Second Tranche Placing Shares, in both cases at the Placing Price of 35 pence per Ordinary Share.

The Company will grant to each participant in the Placing One Warrant to subscribe for Ordinary Shares for every two Placing Shares subscribed, exercisable within 12 months at the Placing Price. The Warrants that are attributable to the First Tranche Placing Shares will not be granted until after the issue of the Second Tranche Placing Shares, and as such are conditional upon, amongst other things, the passing of the Resolutions.

The issue of the Second Tranche Placing Shares and the Acquisition are both subject to, *inter alia*, Shareholder approval at the General Meeting, notice of which is set out at the end of this document on page 481. The General Meeting will be held at 3.00 p.m. on 8 January 2018 at the Hilton London Canary Wharf, Marsh Wall, London E14 9SH.

Trading in the Existing Ordinary Shares is expected to recommence at 8.00 a.m. today. The First Tranche Placing Shares are expected to be admitted to trading on AIM at 8.00 a.m. on 28 December 2017. Assuming the passing of Resolutions 2 and 3 at the General Meeting, the Second Tranche Placing Shares and the Consideration Shares are expected to be admitted to trading on AIM on the earlier of acceptance of the Exchange Offer by the SSNs and receipt of Scheme Approval.

As announced by the Company on 18 December 2017, the Company has formed a strategic partnership with an investment group including ASMA Capital Partners B.S.C.(c) ("**ASMA Capital**"), as the fund manager of IDB Infrastructure II B.S.C.(c) ("**IDB Fund**"), with a view to that investment group making a potential investment of up to US$90 million in the Company for new Ordinary Shares at the Placing Price, including: (i) an initial US$30 million to be invested shortly after the admission to trading on AIM of the First Tranche Placing Shares; and (ii) for a period of 24 months following the completion of the Placing, a right for the investment group to subscribe for an additional US$60 million of new Ordinary Shares at the Placing Price (the "**Additional Potential Investment**").

Savannah and the members of the investment group have agreed to work in good faith to progress and execute the legal documentation necessary to effect the Additional Potential Investment within 30 days of the General Meeting taking place. The Additional Potential Investment is subject to completion of final due diligence, the signature of definitive legal documentation in a form and substance satisfactory to the Company, ASMA Capital and the other investors participating in the proposed investment and each investor's relevant approval processes.

Assuming the Implementation Agreement is agreed, entered into and becomes effective, the Accugas Transaction becomes effective, the Frontier Agreements are agreed, entered into and become effective, the SSNs accept the Exchange Offer or the Seven Energy Court Resolutions are passed at the Seven Energy Court Meetings (if necessary), Scheme Approvals (if necessary) are obtained, Ministerial Consent is received, NSEC Consent is received, creditors under the Accugas IV Facility Agreement, the WCF Agreement, the DSA Facility Agreement and the Promissory Note cooperate with the Transaction, the Accugas Waiver is received and the English High Court administration order in respect of SEIL is granted, the cancellation of the Company's existing quotation on AIM becomes effective and Re-Admission of the Further Enlarged

Share Capital will occur. The Company expects that Ministerial Consent and NSEC Consent will be received by mid-March 2018 and therefore Re-Admission of the Further Enlarged Share Capital is expected to occur by the end of March 2018.

The net proceeds of the Placing will be used to satisfy the cash element of the Acquisition consideration, to advance the Company's Niger assets, to provide general working capital and for general corporate purposes for the Enlarged Group for at least the next 12 months. In the event that the Acquisition does not complete, the Company intends to use the monies raised pursuant to the First Tranche Placing Shares to fund its working capital requirements.

Further details on the Acquisition and the Placing are set out in paragraphs 5, 7, 8 and 18, Part 1 of this document, respectively. The purpose of this document is to set out the details of, and reasons for, the Transaction and explain why the Directors consider the Transaction to be in the best interests of the Company and its Shareholders, and recommend that Shareholders vote in favour of the Resolutions to be proposed at the General Meeting.

You should read the whole of this document and not just rely on the information contained in this letter. In particular, you should consider carefully the "Risk Factors" set out in Part 3 of this document.

2. Key investment proposition

The objective of the Enlarged Group is to deliver material value for its stakeholders through:

- the exploitation and monetisation of the Seven Assets;
- its participation in the Accugas Midstream Business; and
- the exploration and future monetisation of the Company's Nigerien assets; and
- the pursuit of additional expansion opportunities in West Africa.

The Directors believe that an investment in the Company should be attractive to prospective investors for the following reasons:

The Enlarged Group will have a substantial producing asset base, acquired at low cost

As a result of the Transaction, the Enlarged Group will hold working interests in two large, producing onshore oil and gas fields in Nigeria as well as a 20 per cent. interest in the Accugas Midstream Business. The Seven Assets have been certified by LR as having net 2P reserves of circa 92 mmboe, 2C resources of circa 44 mmboe, and expected 2018 net production of greater than circa 20 kboepd.

Accugas Limited currently supplies gas to power station customers that comprise around 10 per cent. of Nigeria's available power generation capacity. The Accugas Midstream Business provides the route to market for the gas from the Enlarged Group's interests in the Uquo Field and Stubb Creek Field.

The Accugas Limited gas network has additional material spare capacity to account for any increased future demand. The Directors believe that Accugas Limited is well placed to benefit from any increased future demand for gas, given a number of barriers to entry, such as the costs of putting in place new infrastructure, which would restrict new entrants to the market.

The enterprise value of the Acquisition is expected to be approximately US$280 million, which comprises approximately US$50 million in cash, US$145 million of equity and US$85 million of assumed debt. This represents an upstream acquisition cost of US$3.1/boe and EV/Capital Invested of approximately 36 per cent. The Board believes that the acquisition metrics are reflective of the distressed nature of the Acquisition.

The Enlarged Group is expected to generate significant, high quality cash flows with material upside

Both the upstream and midstream assets acquired have been operational for a number of years and are expected to be cash flow generative going forward. The Nigeria CPR confirms an indicative average 2018-2022E net free cash flow attributable to the Enlarged Group from the two upstream fields of approximately US$88 million per annum (please refer to paragraph 5 of this Part 1 and Part 11 for further details and the assumptions on which this is based). The Board is also of the view that there is significant medium-term upside potential associated with the conversion of contingent resources into reserves.

The expected forward cash flows are seen by the Board as being stable and high quality, with approximately 90 per cent. of expected 2018-2022E revenues (assumed in the Nigeria CPR) being derived from investment grade end customers (Uquo Field and Stubb Creek Field oil production is covered by a crude offtake agreement with MPN a subsidiary of ExxonMobil, and the Unicem GSA is supported by a Standard Chartered bank guarantee) or being supported by a World Bank Partial Risk Guarantee. In addition, over 90 per cent. of expected production over the 2018-2022E period assumed in the Nigeria CPR is gas, which is contracted at fixed prices and is subject to price indexation clauses which see an expected gas price increase of over five per cent. per annum over the next six years. This implies a limited sensitivity of the Enlarged Group's producing asset portfolio to commodity price movements, and the Nigeria CPR has assessed that a decrease in the base case oil price from US$60/bbl to US$40/bbl (ie. an approximately 30 per cent. fall) leads to only an 11.7 per cent. decrease on a 2P basis in the NPV10 of the Uquo Field and Stubb Creek Field.

The Acquisition complements Savannah's existing portfolio in Niger

The Acquisition balances Savannah's existing high potential exploration asset base in Niger with a material reserves and production base. The Board continues to believe that drilling in Niger offers substantial upside potential and therefore still intends to pursue its previously announced three well drilling campaign. This campaign is expected to target significant prospective oil resources within the Eocene Sokor Alternances primary target.

The Enlarged Group's combined business should provide a strong platform for further Nigerian growth

The Board believes that the Enlarged Group will provide a strong platform to take advantage of what it views as a unique opportunity to acquire further assets in Nigeria at a low point in the cycle. These opportunities are expected to come from a variety of sources, including major oil companies continuing their divestment programmes, a further marginal field bid round which is expected in early 2018, potential partnership opportunities with NNPC and direct negotiations with local/indigenous players, many of whom are seeking partnerships with technically capable companies who have access to capital, to assist them in the exploitation of their asset bases.

The Enlarged Group will have a significantly enhanced corporate profile

The Company has enhanced its governance and operational capabilities through the appointment of a CFO on an interim basis and three highly experienced new Non-Executive Directors to the Board and, following completion of the Transaction, approximately 100 Seven staff to the business, the majority of whom are based in Nigeria.

3. Company history and background

The Company is a public limited company and was incorporated in the UK on 3 July 2014. The Company was admitted to trading on AIM on 1 August 2014 at the same time as raising approximately US$50 million.

The Company is the holding company of the Existing Group and currently operates from offices in London, UK, and Niamey, Niger, with its current principal business being the exploration and expected monetisation of oil located in the R1/R2 PSC Area and the R3/R4 PSC Area in Niger. Since being admitted to trading on AIM, the Company has raised a further US$75 million, which funded the acquisition of the R3/R4 PSC as well as the further development of those Nigerien assets.

Both the R1/R2 PSC Area and the R3/R4 PSC Area are situated in the highly prospective Agadem Rift Basin, part of the Central African Rift System located in South East Niger, and cover an area of approximately 13,655km^2. The R1/R2 PSC Area and R3/R4 PSC Area were formerly part of the original Agadem permit operated by CNPC, 50 per cent. of which CNPC mandatorily relinquished in June 2013 in accordance with the terms of the CNPC PSC.

The Company has proven its ability to operate in Niger, having acquired a 36,948km FTG Survey over the Agadem Rift Basin as well as 806km^2 3D seismic over part of the R3 portion of the R3/R4 PSC Area, and has completed over 3,200 man days of technical work on its assets since inception of the project. As a result of this work, the Company is now in a position to commence a drilling campaign on its assets, and has contracted a drilling rig ("**Rig GW 215**") with Great Wall Drilling Company Niger SARL.

In addition to Savannah's assets in Niger, in November 2016 the Company announced the signature of a Memorandum of Understanding ("**MOU**") with NNPC and NNDC in relation to collaboration between the three parties in the Nigerian section of the Central African Rift System. As part of the announcement of this MOU, Savannah highlighted its intent to pursue other potential strategic opportunities in Nigeria.

Further information on the Company's current portfolio is set out in Part 8 of this document.

4. Information on Seven Energy and background to and reasons for the Transaction

Seven is a private, Nigerian focused integrated oil and gas company, founded in 2007. Between 2007 and 2016, Seven raised US$1.1bn in equity from an investor base which included both institutional and developmental finance investment groups. As at 30 June 2017, Seven had a net debt position of US$887 million.

This capital, and associated, investment enabled Seven to create a business which supplies gas to power station customers that comprise around 10 per cent. of Nigeria's available power generation capacity, as well as to facilitate a 6.8x increase in gross production at OMLs 4, 38 and 41 under its SAA with NPDC.

In the period from 2016, Seven was severely impacted by a number of external challenges, including:

- a substantial backlog of unpaid invoices relating to the supply of gas to Nigerian state-owned power stations, as a result of the liquidity collapse of the Nigerian power sector in 2016 (and prior to the intervention of the Federal Government of Nigeria in September 2017); and
- a loss of material cash flows from the SAA (which Savannah is not acquiring as part of the Acquisition), as the shut-down of the Forcados oil export terminal prevented any "lifts" of oil production from the Seven Group's indirect interest in OMLs 4, 38 and 41, which was followed by the receipt of a Notice of Termination from NPDC in February 2017.

These external challenges occurred at near peak cumulative negative cash outflow and gearing for Seven, meaning that, despite a number of mitigating measures taken (including cost reduction programmes and the suspension of discretionary capital expenditure), Seven has been in default on all of its debt instruments (amounting to approximately US$900 million in aggregate) since May 2017 and has not been servicing this debt. Only US$51 million EBITDAX was realised in the period FY 2016 – H1 2017, vs. Seven's 2016 business plan forecast which estimated EBITDAX generation at US$526 million over the same period.

In the meantime, Seven has been tightly managing its cash flow and working capital in order to continue operations and to preserve the value of its underlying assets while seeking to implement the Transaction.

5. Uquo Field and Stubb Creek Field

Both the Uquo Field and Stubb Creek Field are located onshore in southern Nigeria, in the south east of the prolific petroleum system of the Niger Delta. As further detailed in the Nigeria CPR, a summary of the gross and net 2P and 2C resources and the expected asset free cash flows of the Uquo Field and the Stubb Creek Field are set out below:

Figure 1, Summary of Gross and Net 2P Reserves and 2C Resources

	2P Reserves		*2C Resources*	
	Gross	*Net*	*Gross*	*Net*
Oil & Liquids (mmbbls)				
Uquo	7.8	6.7	2.5	2.1
Stubb Creek	17.1	2.5	1.0	0.2
Gas (bscf)				
Uquo	565.0	495.5	72.5	63.6
Stubb Creek	–	–	515.3	184.3
Total (mmboe)	119.1	91.8	101.5	43.6

Figure 2, Summary of Expected Net Asset Free Cash Flows from Uquo Field and Stubb Creek Field

	CPR Forecast Asset Free Cash Flow (Net), US$m
2018	58.9
2019	78.5
2020	97.7
2021	102.7
2022	102.7

Key assumptions used by LR in its analysis include an oil price of US$60/bbl, inflated at 2 per cent. per annum from 2018, contracted gas prices and DCQ volumes. For full details of the assumptions used by LR in its analysis, please see the Nigeria CPR, as set out in full in Part 11 of this document.

The Uquo Field

SUGL holds a 40 per cent. participating interest in the Uquo Field, with its joint venture partner Frontier holding the remaining 60 per cent. operated interest. Under the terms of its joint operating agreement and technical services agreement with Frontier, SUGL acts as technical and funding partner to Frontier and as project manager for the development of the Uquo Field. SUGL holds an effective 87.7 per cent. gas and 85 per cent. oil revenue interest in the Uquo Field.

Discovered by Shell in 1958, the Uquo Field was awarded to Frontier in the 2003 marginal field round, with Seven acquiring its interest in 2009. Nine wells have been drilled to date on the field and these have proven three separate structures with 19 hydrocarbon bearing reservoirs (14 gas, 4 oil and 1 potential oil) all of which lie within the Early Miocene Agbada Formation. Commercial production from the Uquo Field commenced in 2014.

The Uquo CPF, owned by Accugas Limited and utilised by the Uquo Field, has production capacity of 200 MMscfd, and were designed and built by respected industry contractor Petrofac. The Uquo CPF is modular in nature, with the flexibility to add additional gas processing capacity. Gas is sold to Accugas Limited, as Seven's sole customer, at a current weighted average price of US$1.7/Mcf, which is expected to increase by a weighted average (based on DCQ volumes) of over five per cent. per annum over the next six years and up to 1.5 per cent. per annum thereafter due to price indexation clauses which are included in the downstream GSAs. Current liquids facility capacity at the field is 2 kbopd, with liquids evacuated via pipeline to the QIT, which is located circa10km from the Uquo Field, under a crude offtake agreement.

The Uquo Field is low-cost, with LR having assessed life of field gross capital and operating costs to be US$1.7/boe and US$1.3/boe respectively on a forward basis, in the Nigeria CPR. Near-term operational plans at the field include the completion of the Uquo-9 oil well and an 11km pipeline tie-in to the Uquo CPF in 2018, which is expected to deliver oil production of c.1,800 bopd, and the drilling of one new gas well to maintain GSA DCQs. The Nigeria CPR estimates 2018 gross capital expenditures on the Uquo Field at US$33.5 million.

The Stubb Creek Field

Seven holds an interest in the Stubb Creek Field through its 62.5 per cent. subsidiary Universal. Universal holds a 51 per cent. operated interest in the Stubb Creek Field, with Sinopec holding the remaining 49 per cent. interest.

Discovered by Shell in 1971, the Stubb Creek Field was awarded to Universal as a marginal field in 2003. Seven acquired its interest in 2009 and 2010 through a two stage acquisition of a 62.5 per cent. shareholding in Universal, and brought the field into commercial production in January 2015 using the Stubb Creek EPF, which is capable of processing oil at a gross rate of circa 3 kbopd.

The Stubb Creek Field is an oil asset, with a considerable (86 mmboe gross 2C) undeveloped, non-associated gas resource. Nine wells have been drilled to date on the Stubb Creek Field, of which four were drilled by Shell between 1971 and 1983 and five development wells were drilled, tested and completed between 2007 – 2009 by Universal.

Stubb Creek Field crude is exported from the Stubb Creek Field to the QIT via the FUN Manifold and sold on the same basis and under the terms of the Uquo crude offtake agreement, as detailed above.

It is anticipated in 2018 the existing Stubb Creek EPF will be debottlenecked, to increase oil production capacity to circa 5 kbopd. The contingent gas resources are currently expected to be developed in 2025, as the Uquo Field comes off plateau, and to be tied back to the Uquo CPF via a new 31 km pipeline. The Nigeria CPR estimates 2018 gross capital expenditures on Stubb Creek at US$25.8 million.

Further information on the Uquo Field and the Stubb Creek Field is set out in Part 7 of this document.

6. Map of Seven Assets

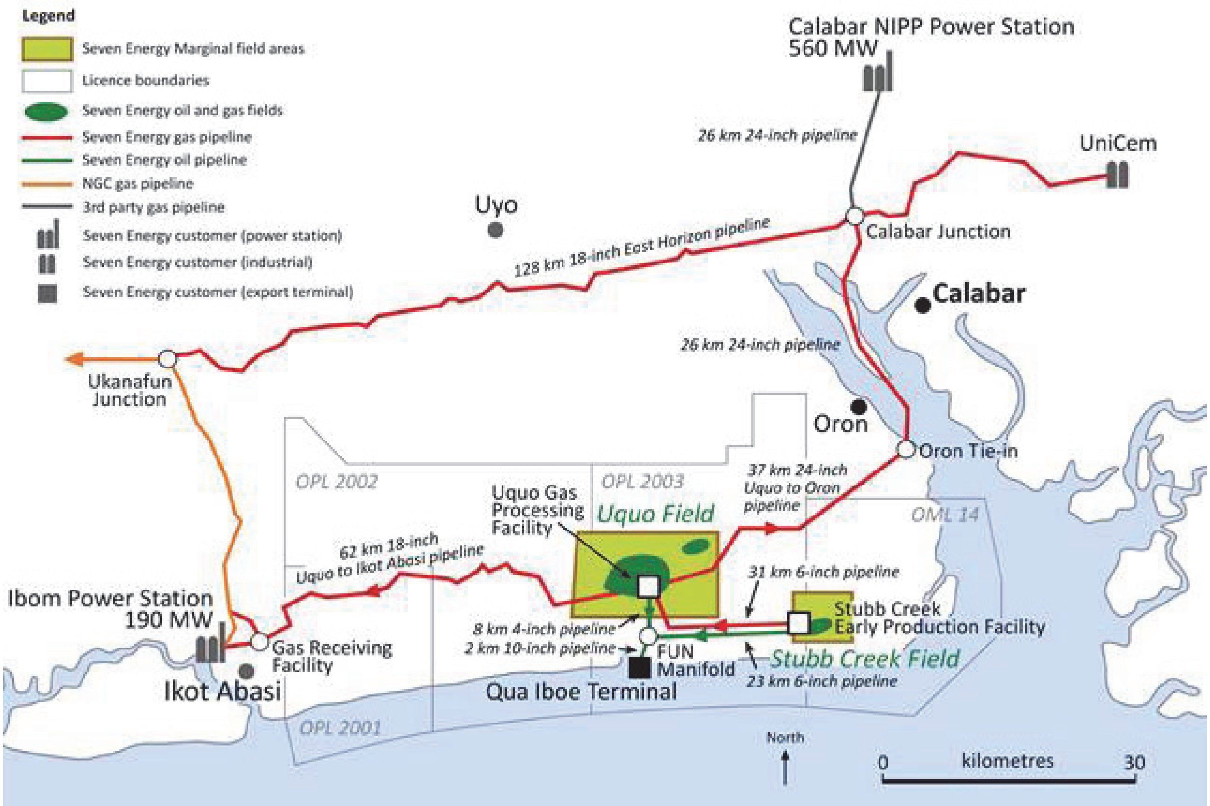


Figure 3, Map of Seven Assets

7. Accugas Midstream Business

The Accugas Midstream Business focuses on the marketing, processing, distribution and sale of gas to the Nigerian market. The business comprises the 200 MMscfd Uquo CPF, a circa 260km pipeline network and long-term GSAs with downstream customers. Accugas Limited buys raw gas from its sole current supplier, the Uquo JV, at a price of US$1.7/Mcf, and sells this gas to three separate customers at a weighted average price of US$3.4/Mcf. This price is expected to increase by an average of over five per cent. per annum over the next six years due to price indexation clauses which are included in the gas sales agreements, the key terms of which are summarised below.

Figure 4, Accugas Summary of Key Gas Sales Agreements

	Calabar NIPP	*Unicem*	*Ibom Power*
Description	Nigerian State Power Plant	Lafarge Cement Plant	Nigerian State Power Plant
Term (Remaining)	20 Years (20)	20 years (14)	10 years (6)
Start Date	September 2017	January 2012	January 2014
Daily Contract Quantity ("DCQ")	131 MMscfd	38.7 MMscfd	19.7MMscfd
Take-or-Pay	80 per cent.	80 per cent.	80 per cent.
Gas Price	US$3.29/Mscf for the first year (price escalation applies)	US$5.00/Mscf	US$2.15/Mscf (price escalation applies)

Savannah has conducted a review of the value of Accugas Limited, which has been assessed as reasonable by LR and incorporated in the Nigeria CPR. The base case NPV10 for Savannah's 20 per cent. interest in the Accugas Midstream Business has been assessed at US$209 million, which, when adjusted for Savannah's *pro rata* share of approximately US$470 million debt which sits at Accugas Limited, represents a base case value of US$115 million.

Accugas Limited's historical focus has primarily been on high volume, but lower price power station customers, which sell their electricity into the regulated Nigerian distribution network. These customers underpinned the contracted forward gas sales which were required to justify the initial capital investment into Accugas Limited's business infrastructure. Going forward, Accugas Limited intends to focus on opportunities to increase gas supplies to new "low volume, high value" industrial customers whose typical alternative source of power is from higher cost diesel-fuelled generation, with Accugas Limited's facilities tying into three principal industrial activity hubs (the areas surrounding Calabar, Port Harcourt and Aba).

The Uquo CPF consists of two identical gas processing trains, each designed to process up to 100 MMscfd. One train has been tested at levels up to 120 MMscfd, and the Directors believe that the Uquo CPF, with limited optimisation, could operate at up to 240 MMscfd on a continuous basis. As such, spare capacity of up to circa 50 MMscfd is intended to be used by Savannah and the Investors as part of the development of the Accugas Midstream Business going forward. There also exists at least 300 MMscfd spare capacity in Accugas Limited's pipeline network. Three non-binding heads of terms have been signed by Accugas Limited with potential new industrial customers in the Calabar area for gas sales of circa 5 MMscfd at an average price of US$7.5/Mcf.

8. Acquisition of Accugas Limited in conjunction with a private equity investor

The Company has entered into a conditional investment agreement pursuant to which a private equity investor, African Infrastructure Investment Fund 3 ("AIIM"), which, together with potentially one or more co-investors, will acquire an 80 per cent. interest in Accugas (to be effected concurrently with the completion of the Acquisition). The Company will acquire a 20 per cent. carried interest in the business. The proposed investment by the Company and the Investors remains subject to the satisfaction of certain conditions including the completion of the Acquisition (further details of which are set out in paragraph 5.1.4 of Part 14 of this document).

Pursuant to the conditional investment agreement referred to above, AIIM will invest in Accugas, in aggregate, at least US$45 million in return for 80 per cent. ownership and will carry Savannah's 20 per cent. interest with an assumed non-recourse funding cost of 10 per cent. compounded annually against Savannah's 20 per cent. carried interest. AIIM is in discussion with one or more co-investors, including IDB Infrastructure Fund II, to increase this amount to US$60 million. Savannah will have the right to acquire a further 10 per cent. of the Accugas Midstream Business for a price equal to 10 per cent. of the total capital invested by the shareholders in Accugas at the time the option is exercised, uplifted at an annualised rate of 10 per cent. Savannah will have the right to appoint one out of the four directors on the board of Accugas Limited and two out of the five directors on the board of Accugas Holdco and the shareholders' agreement will contain typical reserved matters. The agreed intention is to distribute 100 per cent. of profits arising from the Accugas Midstream Business (through which the associated cost of the carried finance would be repaid), subject to the Accugas Midstream Business retaining a minimum cash balance after servicing third party debt.

Savannah and the Investors have also agreed outline terms of a relationship agreement to be entered into between Savannah and Accugas Limited and the terms of a new gas sales agreement expected to be entered into between Accugas Limited and the Uquo JV. Pursuant to the proposed relationship agreement, Accugas Limited will be responsible for the construction of certain infrastructure including a pipeline to link the Stubb Creek Field to the Uquo CPF. Savannah will not be obliged to proceed with gas development at the Stubb Creek Field, but, if such gas is developed, Savannah will use reasonable endeavours to sell such gas to Accugas Limited for the same price as gas from the Uquo Field. The price under the proposed new GSA is expected to be $1.7/Mcf and this will be increased annually to reflect the price indexation in Accugas Limited's downstream GSAs. In the event of any new GSA, it is intended that SUGL will receive 50 per cent. of any price agreed for sales of such gas by Accugas Limited in excess of US$3.4/Mcf pro-rata to its economic interest.

AIIM, a subsidiary of Old Mutual Investment Group, is one of the longest running and largest infrastructure fund managers in Africa, with US$2bn assets under management over seven funds which have made 45 investments and 13 exits over 17 years. AIIM also has extensive Nigerian experience, with total committed and earmarked capital of greater than US$300 million in country, the majority of which is in the power, energy and telecommunications sectors.

9. The Nigerian opportunity

The Board believes that the expansion of the Company into Nigeria through the Acquisition represents a compelling opportunity to expand and diversify its operations into a country with highly attractive oil and gas characteristics.

A strong cash return jurisdiction with a well-established oil and gas industry

Oil and gas industry contractors have been operating in Nigeria since the 1960s, and a well-established oil service sector exists in country. Close to US$100bn in net free cash flow has been generated by oil & gas companies operating in Nigeria since 1965, and these contractors have seen a net cash flow/capex ratio of 1.4x on a 10 year historical rolling average basis.[1]

Nigeria has also generated, and continues to generate, a material portion of the upstream cash flows of the major global oil and gas companies. For instance, over the past ten years, Nigeria has driven an average of 16 per cent. of the upstream cash flows of Chevron, ENI, ExxonMobil, Shell and Total.[2]

To support the generation of these cash flows, an active and long-standing oil service sector operates in country, with most major service companies present in Nigeria through a partnership with a local company. Over US$365bn has been invested in Nigeria since 1965, which includes the drilling of over 3,700 exploration & appraisal wells and represents average oil and gas investment of circa US$7bn per annum.[3]

World class geology

At the end of 2016, Nigeria's proved oil reserves were estimated at approximately 37.1 bn bbls of oil, the second largest in Africa and eleventh largest globally. Nigeria's proved gas reserves were estimated to stand at approximately 187 tcf, the largest in Africa and tenth largest globally.

The majority of Nigeria's oil and gas reserves are located in the Niger Delta, one of the world's largest and most prolific hydrocarbon deltas, covering an area of circa 300,000km^2. Hydrocarbon reservoirs in the Niger Delta lie mainly within the Agbada Formation, which extends from onshore to shallow water, and the Uquo Field and the Stubb Creek Field both lie within structural targets in the Agbada Formation. This formation includes interbedded sandstones and claystones, forming sequences of reservoirs and seals where oil and gas are then trapped by faulting and associated folding. The Akata Formation is a deeper water claystone unit which, together with claystones in the Agbada formation, form prolific source rocks for the delta.

[1] Source: Wood Mackenzie, Upstream Data Tool 2017-Q3 for underlying historical net cash flows and capex data
[2] Source: Wood Mackenzie, Upstream Data Tool 2017-Q3
[3] Source: Wood Mackenzie, Upstream Data Tool 2017-Q3

Although the Niger Delta is mature in terms of drilling and seismic density, it remains extremely prospective and continues to offer significant upside, with the USGS estimating YTF resources in the province at 25 billion boe (P50).

Prime market for further consolidation with limited competition for deals

The Board believes that a current favourable set of conditions in country presents a unique opportunity for Savannah to acquire further assets in Nigeria, and to use the Acquisition as a platform for further growth at a low point in the cycle.

These opportunities are expected to come from a variety of sources, including major oil companies continuing their divestment programmes, a further marginal field bid round which is expected in early 2018, potential partnership opportunities with NNPC and direct negotiations with local/indigenous players, many of whom are seeking partnerships with technically capable companies who have access to capital, such as Savannah, to assist them in the exploitation of their asset bases.

There has been a material decrease in oil and gas M&A in Nigeria since its 2014 peak, and a significant reduction in equity and debt capital available to Nigerian focused oil and gas companies has been observed following the oil price downturn of 2015. The Board therefore believes that Nigeria offers a competitive environment for additional further growth and potential acquisition opportunities.

The Enlarged Group has existing strong and growing relationships in Nigeria

The Company entered Nigeria in November 2016 with the signature of an MOU with NNPC and NNDC, and, at this time, indicated its strategic intent to pursue other potential opportunities in country. The Company has continued to build and enhance relationships with key stakeholders in country, and it is expected that these relationships will facilitate a strong ability to operate and expand in country.

10. Niger Operational Campaign

Following completion of the Placing, the Company intends to pursue its previously announced three well drilling campaign in Niger. Drilling is expected to commence following the issue of the Second Tranche Placing Shares using the GWDC 215 rig as previously announced, and is intended to target three prospects on the R3 part of the R3/R4 PSC Area (all defined on 3D seismic). Wells are expected to cost US$6 – 8 million per well for this campaign.

Each well is expected to assess potential oil pay in the Eocene Sokor Alternances as a primary target, and in the Eocene-Oligocene Upper Sokor as a secondary target. As part of the Transaction, and in addition to the Nigeria CPR produced by LR, CGG has prepared the Niger CPR covering the Savannah PSCs. As part of the Niger CPR, CGG has conducted a review of nine exploration leads and prospects ("**Targets**") across the Savannah PSCs, of which three of these have been indicatively selected for drilling in Savannah's upcoming operational campaign. CGG has assessed these Targets to carry a low risk profile (i.e. similar to those drilled elsewhere in the basin to date). Proposed well targets and order of drilling remain subject to change.[4]

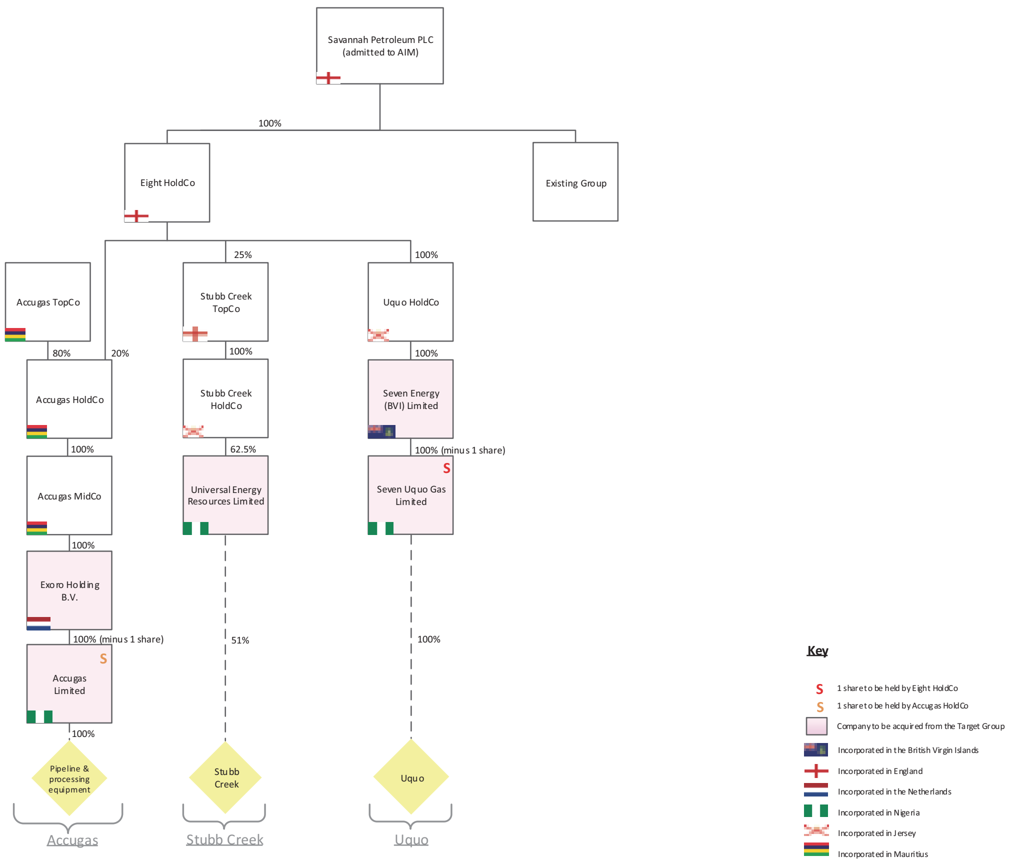
[4] Volumes are CGG estimates of mean unrisked recoverable resources and assume a recovery factor of 30 per cent.

Figure 5, Table of Targets

	PSC Area	*Alternances Unrisked Mean Recoverable Resources, mmbbls*	*Upper Sokor Unrisked Mean Recoverable Resources, mmbbls*	*Total Unrisked Mean Recoverable Resources, mmbbls*
Bushiya	R3	28	38	36
Amdigh	R3	33	25	39
Kunama	R3	24	78	35
Total		85	141	110

11. Anticipated corporate structure of the Enlarged Group

Figure 6, Anticipated Corporate Structure of the Enlarged Group



12. Summary financial information and current trading of the Existing Group

The summary financial information presented below has been extracted without material adjustment from the audited consolidated financial statements for the Company for the 12 month period ended 31 December 2016 and the unaudited interim financial information for the six month period ended 30 June 2017.

The Directors expect the historical financial statements of the Existing Group and the Seven Group not to accurately reflect the Enlarged Group's future performance. Issues surrounding the Enlarged Group's potential future cash flow generation capacity are outlined in the Nigeria CPR and Niger CPR.

Figure 7, Summary Financial Information of the Existing Group

	FY 2016 ($'000)	*H1 2017 ($'000)*
Income Statement Selected Line Items		
Revenue	0	0
Operating Profit/(Loss)	(8,412)	(5,944)
Profit/(Loss) Before Tax	(8,331)	(5,805)
Profit/(Loss) After Tax	(9,833)	(5,812)
Balance Sheet Selected Line Items		
Total Assets	127,002	119,871
Total Liabilities	(8,563)	(6,455)
Net Assets	118,439	113,416
Net Debt /(Cash)	(23,061)	(8,409)
Cash Flow Statement Selected Line Items		
Cash Flow from Operating Activities	(8,457)	(4,253)
Cash and Cash Equivalents	23,061	8,409

13. Summary financial information and current trading of Seven Energy

The summary financial information presented below has been extracted without material adjustment from the historical financial information of the Seven Group as set out in Part 9A of this document. This summary financial information has been derived from the unaudited consolidated financial statements of the Seven Group for the 12 month period ended 31 December 2016 and the unaudited consolidated financial statements of the Seven Group for the six month period ended 30 June 2017, as adjusted by Savannah for the purposes of presenting such information in accordance with Savannah's own accounting policies and to reflect the latest certified reserves information set out in Part 11 of this document.

The summary consolidated financial information of the Seven Group below includes interests not being acquired as part of the Acquisition, notably those relating to the SAA with NPDC and the Anambra basin, an exploration asset; the information also reflects Seven's 100 per cent. interest in Accugas Limited (via its shareholding in Accugas Limited's parent company, Exoro). During the 2016 period through to June 2017, there were no revenues or material costs relating to the SAA due to damage to the Trans Forcados pipeline leading to a shutdown of the pipeline and terminal. As at 30 June 2017, following an impairment of Seven's interest in the SAA, the remaining balance sheet position was a net US$38 million due to NPDC, which is the subject of ongoing settlement discussions. It should be noted that the Directors believe that the historical financial information presented below is therefore not representative of the forward cash flow generation potential of the Seven Assets.

An unaudited pro forma statement of net assets of Enlarged Group is set out in Part 10 of this document.

Figure 8, Selected line items from the Seven Group's income statement, balance sheet and cash flow statement

	FY 2016 ($'000)	*H1 2017 ($'000)*
Income Statement Selected Line Items		
Revenue	101,920	61,750
Gross Profit/(Loss)	91,557	(65,902)
Operating Profit/(Loss)	(238,489)	(295,668)
EBITDAX*	107,962	(57,241)
Profit/(Loss) Before Tax	(302,701)	(354,350)
Profit/(Loss) After Tax	(207,173)	(325,996)
Balance Sheet Selected Line Items		
Total Assets	1,648,117	1,343,411
Total Liabilities	(1,479,282)	(1,499,705)
– Includes borrowings of	(835,981)	(838,850)
Net Assets	168,835	(156,294)
Net Debt	(823,177)	(824,700)
Cash Flow Statement Selected Line Items		
Cash Flow from Operating Activities	57,239	23,203
Cash and Cash Equivalents	12,804	14,150

* EBITDAX is calculated as operating profit/(loss) before depletion and impairments. Seven reports a segmental analysis in the notes to its accounts. The EBITDAX for Seven's South East business (which includes Uquo, Stubb Creek and Accugas Limited) in 2016 and H1 2017 was US$46.9 million and US$49.4 million respectively.

14. Future prospects of the Enlarged Group

The Directors believe that the Enlarged Group will have a valuable and stable asset base which will provide a platform to accelerate growth plans and realise future potential. In the near-term, significant benefits are expected to be realised through the cash flows which are expected to be generated by the Uquo Field and Stubb Creek Field, as well as through exposure to the upside potential inherent in the Company's upcoming three well drilling campaign in Niger which is expected to target significant prospective oil resources. The Board also expects the Enlarged Group's governance, management and operational expertise to be enhanced through the new appointments to Savannah's Board and through the integration of the Savannah and Seven businesses. The introduction of a dividend policy for the Enlarged Group is intended to demonstrate the Board's continued intention to exercise financial discipline going forward.

Longer term, the Board expects the Enlarged Group to benefit from the monetisation of potential discoveries in Niger, as well as from the commercialisation of circa 31 mmboe net 2C gas resources at the Stubb Creek Field. The Directors are of the view that there is material growth potential in the Accugas Midstream Business, which is expected to be achieved in partnership with the Investors and to come from the addition of new, potentially higher value customers and an associated infrastructure build-out. As discussed in paragraph 2 above, the Board believes that the Enlarged Group's combined business will provide a strong platform for further inorganic growth in Nigeria and the region, and intends to take advantage of what it views as a unique opportunity to acquire further assets at a low point in the cycle.

15. Directors, Senior Managers and employees

Directors

Stephen ("Steve") Ian Jenkins, aged 59 – *Non-Executive Chairman*
Steve joined Savannah as Non-Executive Chairman in July 2014. He is widely recognised as one of the most capable oil and gas executives in the UK, having delivered for his investors as CEO of Nautical Petroleum a £414 million sale to Cairn Energy in Q3 2012. Prior to Nautical Petroleum, Steve held a variety of senior roles at Nimir Petroleum, an emerging markets focused private Saudi Arabian company with extensive global exploration and production interests. Steve is a geologist by profession and is currently Chairman of the Oil and Gas Independents Association, one of the principal oil and gas trade bodies in the UK.

Rt. Hon. Sir Stephen O'Brien, aged 60 – *Non-Executive Vice Chairman*
Stephen is a former UN Under Secretary General for Humanitarian Affairs and Emergency Relief Coordinator. Prior to this role he was a British MP, during which time he served as Parliamentary Under-Secretary of State

for International Development and as the Prime Minister's Envoy & UK Special Representative for the Sahel as well as a series of shadow ministerial roles. Before entering politics, Stephen was International Director and Group Secretary of the FTSE 100 listed global building materials company, Redland plc. Stephen began his career as a corporate lawyer with Freshfields Bruckhaus Deringer LLP. He is a serving member of the Privy Council and was knighted in 2017 for his achievements and commitments to international development.

Andrew Allister Knott, aged 37 – *Chief Executive Officer*
Andrew was the principal founder of Savannah, becoming a Director of the Company in July 2014. He has held leading roles in the European oil and gas sector. Andrew has led all of the Company's key growth initiatives, including the acquisition of the Savannah PSCs and the Company's expansion into Nigeria. Prior to establishing Savannah, Andrew was previously Head of Global Energy Investments for GLG Partners/MAN Group which, at December 2012, was the largest listed hedge fund in the world by assets. Andrew has also held various roles at Merrill Lynch and Dresdner Kleinwort Wasserstein.

Isatou Semega-Janneh, aged 41 – *Chief Financial Officer (on an interim basis)*
An accountant with over 17 years' experience, Isatou has led Savannah's finance function since joining the Company in January 2015. Prior to joining Savannah, she spent nine years with BP plc in a variety of roles, most recently as Financial Controller for BP's operations in North Africa (Algeria, Libya and Morocco). Isatou has extensive experience of implementing and managing financial and regulatory compliance systems in emerging market oil and gas environments and of managing large, multi-country finance teams. Since joining Savannah, she has implemented effective internal controls, processes and procedures for the Company, as well as putting in place an appropriate financial reporting process for the business and managing the Company's existing debt facility arrangements.

Marco ("Mark") Iannotti, aged 49 – *Non-Executive Director*
Mark was appointed to the Board of Savannah in July 2014. He is an experienced capital markets professional with over 20 years' experience in EMEA equities, which has been largely focused around the oil and gas sector, and currently acts as Managing Director and Head of Securities, UK & Europe of Canaccord Genuity Group Inc. Previously, he was a member of Bank of America Merrill Lynch's EMEA Executive Committee and Head of its EMEA Equity Research Division. Mark began his career at Wood Mackenzie Consultants, focusing on the Asian and Indian sub-Continent energy markets. He subsequently held senior equity research positions at Cazenove & Co, Credit Suisse and Citigroup.

David Lawrence Jamison, aged 73 – *Non-Executive Director*
David was appointed to the Board of Savannah in July 2014. He was one of the founders of the modern-day Vitol, having executed a management buyout of the company alongside three partners in 1976. He left Vitol in 1986 to operate as an independent venture capitalist in the upstream oil and gas industry. David's principal investment vehicle today is DLJ Associates Limited which seeks to act as agent and advisor on upstream oil and gas transactions. Previous companies David has held integral roles at include Russian focused oil and gas company Sibir Energy plc (founder director) and independent gasoline company Blue Ocean Associates Limited (founder director).

David Clarkson, aged 65 – *Non-Executive Director*
David was formerly a member of BP's Group Leadership Team and Senior Vice President for Projects and Engineering (Upstream) at BP. In this role, he had responsibility for a functional business unit that managed a circa US$20 billion annualised capex budget and employed circa 1,500 project and engineering professionals. Throughout a 38 year career with BP, David held a variety of other senior project management and delivery roles in countries including Iraq, Indonesia, the USA and the UK. David is a Chartered Engineer and Fellow of the Institute of Mechanical Engineers.

Michael Jon Wachtel, aged 51 – *Non-Executive Director*
Michael serves as Head of Corporate and Head of Energy and Natural Resources at Clyde & Co LLP, a leading international law firm. Michael's practice has a strong emerging market focus and provides companies with a full range of legal services including corporate, M&A, financing, governance and regulatory compliance. His client list includes major oil and gas companies and oil services companies, as well as many of the leading independent oil companies. As a member of Clyde & Co LLP's management Board, he is responsible, alongside the other members, for the running of a business with over 45 international offices and a global turnover in excess of £500m. Prior to entering law, Michael worked as an oil and gas field engineer in various West African countries for Schlumberger and Geoservices.

Senior Managers

In addition to the Directors, the following Senior Managers are considered relevant in establishing that the Enlarged Group has appropriate expertise and experience for the management of its business.

(a) *Existing Group*

Jessica Hostage, aged 32 – *VP Strategy and Implementation*

With a background in oil and gas equities and investment banking, Jessica has over 10 years' experience in the sector. She joined Savannah immediately following the IPO in 2014 from Canaccord, where she was the No. 1 ranked specialist sales person in the Small/Mid-Cap Oil & Gas Extel rankings (2013 and 2014). Previously she worked on a range of M&A and equity capital market transactions in the Energy & Power investment banking team at Bank of America Merrill Lynch. Since joining Savannah, Jessica has had oversight of a range of commercial and business development projects, investor relations and communications.

Yacine Wafy, aged 34 – *Country Manager, Niger*

Yacine is a Nigerien national. He joined Savannah from leading Niamey-based construction company Primo et Geb where he served as Chief Executive Officer. As such, he has significant experience managing large scale projects in Niger. He studied at George Washington University in Washington, D.C. Yacine is responsible for the day to day management of the Company's operations in Niger, as well as management of key stakeholder relationships in country.

Antoine Richard, aged 50 – *VP Operations*

Antoine has over 20 years' experience in the oil and gas industry, including over 10 years' experience in West Africa, and joined Savannah as VP Operations in August 2016. Prior to joining Savannah, Antoine spent 10 years with Perenco in a variety of roles, including Global HSE Manager, Country Manager roles for DR Congo, Egypt and Venezuela and Area Manager for Egypt & North Africa. He has a strong operational background, with experience of onshore facilities design and operation, production optimisation, management of drilling campaigns and desert environment seismic acquisition.

Phil Magor, aged 62 – *Chief Geologist*

Phil has enjoyed a 34 year career in the global oil and gas industry. He is a highly African-experienced geologist who has successfully managed onshore desert environment exploration programs throughout his career. Phil joined Savannah from Maersk Oil, where he was a senior member of the exploration and development team for the multi-billion barrel Dunga project in Kazakhstan. Other countries in which Phil has lived and worked include Angola, Sudan, Malaysia, Ethiopia, Papua New Guinea, Pakistan, the United Arab Emirates and Libya.

(b) *Seven Group*

Manish Maheshwari, aged 50 – *MD Nigeria*

Manish joined Seven Energy as CEO in April 2017. Previously Manish was the CEO of Essar Oil Ltd. E&P Business, where he successfully led a turnaround of the business which culminated in the sale of the Indian assets to a consortium comprising of Rosneft, Trafigura and UCP for US$12.9 billion. His earlier assignments in the oil and gas sector were as Managing Director of Hindustan Oil Exploration Company Limited, a subsidiary of ENI S.p.A. and with Tata Group. Manish has led initiatives to induct strategic and financial investors in various oil and gas ventures and ensured smooth transition over time involving majors like Eni and Unocal. He has been instrumental in strategising and repositioning the companies as credible operators delivering multi-fold growth from onshore and offshore assets in a safe, timely and cost-efficient manner. Manish has been involved in negotiating Production Sharing Contracts with the Government, Joint Operating Agreements with National Oil Companies, Crude Oil Sales Agreement with Government nominated refineries and GSAs with aggregators and end users. Manish has a Bachelor (Hons.) in Chemical Engineering and Masters in Business Administration with specialisation in finance.

Chris Thomas, aged 56 – *Interim CFO Nigeria*

Chris joined Seven Energy in 2009, and has over 30 years' experience in corporate finance generally and over 20 years in the energy sector. Chris was a founding director of Melrose Resources plc, the former London Stock Exchange FTSE 250 international E&P company with interests in EMEA and the US. Chris is a member of the Institute of Chartered Accountants in England and Wales and has a BA from the University of Exeter.

Ian Brown-Peterside, aged 46 – *General Counsel Nigeria*
Ian joined Seven Energy in August 2014 and has over 15 years' experience in the industry. Before joining Seven Energy, Ian worked for BG Group, holding various positions including Principal Counsel, Vice President Legal for BG Kazakhstan, Legal Director of Karachaganak Petroleum Operating BV and Commercial Manager, Operated Assets (Nigeria). Ian was admitted as a solicitor in England & Wales in 1999 and holds a BSc Honours degree from King's College, University of London.

16. Health, safety and environment

Savannah considers that a high standard of health and safety performance and environmental protection are critical to the ongoing success of the Company and the Enlarged Group, as well as the commitment to act in a responsible manner towards the its stakeholders. The Group has Health and Safety, Environmental and Corporate Social Responsibility policies in place, which are supported by a robust health, safety, security and environmental ("**HSSE**") management system which aligns with international management system standards and takes a proactive approach to the identification and management of HSSE risks.

The system aims to ensure adherence to applicable international and local legislation, regulatory requirements as well as the consideration of "best practices" within the international oil and gas industry. Savannah expects its suppliers, contractors and partners to share and enforce similarly high HSSE standards.

17. Competition

Savannah's operations are currently focused around West Africa, specifically, Niger and Nigeria.

While Savannah faces a competitive environment for acquiring assets and securing trained personnel and services, the level of competition across Nigeria and Niger is believed by the Board to have reduced significantly over the course the past twenty four months as a result of the steep oil price decline that has been experienced since 2015.

The Board believes that this reduced level of competition potentially creates an opportunity for Savannah to acquire additional oil and gas assets over time, at attractive valuations. However, the Board also recognises that were oil prices to rapidly appreciate and/or substantial M&A activity to occur in Niger and Nigeria, then the competitive environment for assets in each country would almost certainly intensify, as would industrial cost pressures.

18. Details of the Placing

Each of Barclays, Mirabaud and Shore Capital has conditionally agreed, pursuant to the Placing Agreement, to act as agent for the Company and use its reasonable endeavours to procure subscribers for the Placing Shares at the Placing Price. The Placing is not being underwritten. The Placing will raise approximately US$125 million for the Company (before commissions and expenses). The Placing Shares are being placed with certain existing and new institutional and other sophisticated investors.

The Company has placed the First Tranche Placing Shares at the Placing Price conditional on their admission, which is expected to occur at 8.00 a.m. on 28 December 2017. The First Tranche Placing Shares will be issued pursuant to the existing pre-emption disapplication authority granted to the Directors by Shareholders at the annual general meeting of the Company held on 22 June 2017. The placing of the First Tranche Placing Shares will raise, in aggregate, gross proceeds of approximately US$12.9 million. Following their admission, the First Tranche Placing Shares will represent approximately 9.1 per cent. of the Company's then enlarged issued ordinary share capital and the holders of the First Tranche Placing Shares will be eligible to vote on the Resolutions.

In addition, the Company has conditionally placed the Second Tranche Placing Shares. As the Company will have utilised all of the Directors' existing authority to allot shares for cash on a non pre-emptive basis following admission of the First Tranche Placing Shares, the proposed placing of the Second Tranche Placing Shares to raise, in aggregate, approximately a further approximately US$112.1 million gross, is conditional upon, *inter alia*, the passing of Resolutions 2 and 3 at the General Meeting, which is expected to be held on 8 January 2018, and admission of the Second Tranche Placing Shares and the Consideration Shares occurring on the earlier of the acceptance of the Exchange Offer by the SSNs or receipt of the Scheme Approvals. Following their admission, the Second Tranche Placing Shares will represent approximately 26.7

per cent. of the Company's then enlarged issued ordinary share capital (the "**Further Enlarged Share Capital**").

Additionally, the Company will grant to each participant in the Placing one Warrant to subscribe for Ordinary Shares for every two Placing Shares subscribed, exercisable at the Placing Price. Full particulars of the Warrants appear in paragraph 9.2.13 of Part 13 of this document. The Warrants that are attributable to the First Tranche Placing Shares will not be granted until after the issue of the Second Tranche Placing Shares, and as such are conditional upon, amongst other things, the passing of the Resolutions.

The Placing Shares will rank *pari passu* in all respects with the Existing Ordinary Shares, including the right to receive all dividends and other distributions declared, paid or made after the date of issue, and will be placed free of any expenses and stamp duty.

Under the terms of the Placing Agreement, Barclays, Mirabaud and Shore Capital will receive commission from the Company conditional on the relevant admission and the Company will give customary warranties and undertakings to Strand Hanson, Barclays, Mirabaud and Shore Capital in relation, *inter alia*, to its business and the performance of its duties. In addition, the Company has also appointed EAS Advisors, LLC, through Odeon Capital Group LLC, to act as its non-exclusive placement agent. There is no other investment banker, broker, finder or other intermediary that has been retained by or is authorised to act on behalf of the Company who might be entitled to any fee or commission in connection with the Placing. In addition, the Company has agreed to indemnify Strand Hanson, Barclays, Mirabaud and Shore Capital in relation to certain liabilities that they may incur in undertaking the Placing. Strand Hanson and Barclays each has the right to terminate the Placing Agreement in certain circumstances prior to the relevant admission, in particular, in the event that there has been, *inter alia*, a material breach of any of the warranties given by the Company and/or the Directors to Strand Hanson, Barclays, Mirabaud and Shore Capital.

In the case of investors receiving Placing Shares in uncertificated form, it is expected that the appropriate CREST accounts will be credited for the First Tranche Placing Shares with effect from 28 December 2017 and the Second Tranche Placing Shares and the Consideration Shares on the day of their issue. In the case of investors receiving Ordinary Shares in certificated form, it is expected that certificates will be dispatched by post, within 14 days of the date of the relevant admission.

Further details of the Placing Agreement are set out in paragraph 9.2.1 of Part 13 of this document.

19. Use of proceeds

The gross proceeds of the Placing to the Company are expected to be approximately US$125 million (approximately £93.3 million) and are currently intended to be applied as follows:

Figure 9, Use of Proceeds

Use	*US$ million*
Cash consideration payable to the holders of the SSNs	50.8
Other Transaction costs	20.0
Niger drilling programme	37.4
Working capital and corporate purposes	16.8
Total	125.0

In the event that the issue of the Second Tranche Placing Shares does not complete, the Company intends to use the monies raised pursuant to the issue of the First Tranche Placing Shares to fund its working capital requirements.

In addition, in the event all of the Warrants are exercised, the Directors expect to receive gross proceeds of approximately US$62.5 million of additional funds that, with the monies referred to above, will be used to further advance the Company's Niger assets and for general corporate purposes.

20. Corporate governance

The Board recognises its responsibility for the proper management of the Company and the importance of sound corporate governance commensurate with the size and nature of the Company and the interests of its shareholders. The Board is therefore committed to maintaining high standards of corporate governance. As an AIM quoted company, Savannah is not required to comply with a particular corporate governance regime. Nevertheless, the Directors recognise the value of the QCA Code and the Corporate Governance Code and the Company complies with their principles and provisions where relevant and appropriate, having regard to the size, current stage of development and resources of the Group and the direct cost of delivering effective corporate governance.

Please refer to paragraph 20 of this Part 1 and Part 16 of this document for a detailed description of the Company's current and proposed corporate governance structure and practices.

21. The Takeover Code

The Takeover Code is issued and administered by the Panel. The Panel has been designated as the supervisory authority to carry out certain regulatory functions in relation to takeovers pursuant to the Directive. Following the implementation of the Directive by the Takeovers Directive (Interim Implementation) Regulations 2006, the rules set out in the Takeover Code now have a statutory basis.

The Company is a public limited company incorporated in England & Wales and is admitted to trading on AIM. Accordingly, the Takeover Code applies to the Company.

Under Rule 9 of the Takeover Code, where 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 persons acting in concert with him are interested) carry 30 per cent. or more of the voting rights of a company which is subject to the Takeover Code, that person is normally required to make a general offer to all the shareholders of that company to acquire their shares. Similarly, when any person, together with persons acting concert with him, is interested in shares which, in aggregate, carry not less than 30 per cent. of the voting rights of a company and does not hold shares carrying more than 50 per cent. 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, a general offer will normally be required in accordance with Rule 9.

An offer under Rule 9 must be made in cash (or be accompanied by a cash alternative) and at not less than the highest price paid by the person required to make the offer, or any person acting in concert with him, for any interest in shares of the company during the 12 months prior to the announcement of the offer.

Under the Takeover Code a concert party arises when persons acting together pursuant to an agreement or understanding (whether formal or informal) cooperate to obtain or consolidate control of, or frustrate the successful outcome of an offer for, a company subject to the Takeover Code. Control means an interest or interests in shares carrying an aggregate of 30 per cent. or more of the voting rights of the company, irrespective of whether the holding or holdings give *de facto* control.

The Panel has previously deemed that a concert party is in existence between Andrew Knott and his family members, Aralia Capital SA (which also includes the holding of Peleng Holding Corporation, wholly owned by the same investor as Aralia Capital SA) and Luzon Investments S.A. (the "**Existing Concert Party**"). The Existing Concert Party is currently interested, in aggregate, in 36,856,453 Ordinary Shares, representing 13.4 per cent. of the Existing Ordinary Shares.

Following First Admission, the Existing Concert Party will be interested, in aggregate, in 36,856,453 Ordinary Shares, representing 12.2 per cent. of the Initial Enlarged Share Capital. Following Second Admission and Re-Admission, the Existing Concert Party will be interested, in aggregate, in 38,987,453 Ordinary Shares, representing 4.4 per cent. of the Further Enlarged Share Capital.

Further details on the members of the Existing Concert Party are disclosed in the Company's circular to shareholders dated 11 March 2015.

Further information on the provisions of the Takeover Code can be found in paragraph 18 of Part 13 of this document.

22. Lock-ins and orderly market arrangements

The new Ordinary Shares to be issued to the holders of the SSNs and the Second Bilateral Facility pursuant to the Capital Restructuring (please refer to the Transaction Overview in Part 2 of this document for further details) will be subject to lock-in provisions that will restrict transfers of such shares for a period of six months from their date of issuance without Savannah's prior consent in order to ensure an orderly market in the Ordinary Shares. These lock-in arrangements will be subject to customary exceptions, including a transfer pursuant to the acceptance of a takeover.

Pursuant to the Placing Agreement, the Company has agreed that it will not, without the prior written consent of Barclays and Strand Hanson (not to be unreasonably withheld or delayed), for a period ending 12 months after the admission of the Second Tranche Placing Shares, issue, offer, lend, mortgage, assign, charge, pledge, sell, contract to sell or issue, sell any option or contract to purchase, purchase any option or contract to sell or issue, grant any option, right or warrant to purchase, lend or otherwise transfer or dispose of, directly or indirectly, any Ordinary Shares in the Company or any securities convertible into or exercisable or exchangeable for Ordinary Shares or enter into any swap or other agreement or transaction that transfers, in whole or in part, any of the economic consequences of ownership of the Ordinary Shares, subject to certain exceptions. The exceptions to these lock-in arrangements include:

- the issue by the Company of the Placing Shares;
- the issue by the Company of the Consideration Shares;
- the issue of Ordinary Shares by the Company pursuant to any employee share option scheme;
- following the period ending 90 days after the admission of the Second Tranche Placing Shares, the issue of Ordinary Shares by the Company for the purposes of funding, or providing consideration for, an acquisition of assets in connection with its oil and gas business; and
- following the period ending 180 days after the Re-Admission, the issue of Ordinary Shares by the Company for the purposes of funding its drilling campaign in Niger.

Further pursuant to the Placing Agreement, Andrew Knott has agreed that he will not, without the prior written consent of Strand Hanson (not to be unreasonably withheld or delayed), following consultation with Barclays, for a period ending 90 days after the admission of the Second Tranche Placing Shares, engage in any offer, sale, contract to sell, grant or sale of options over, purchase of any option or contract to sell, transfer, charge, pledge, grant of any right or warrant to purchase or otherwise transfer, lend, or dispose of, directly or indirectly, any Ordinary Shares or any securities convertible into or exercisable or exchangeable for Ordinary Shares or the entry into of any swap or other agreement that transfers, in whole or in part, any of the economic consequences of ownership of Ordinary Shares, subject to certain customary exceptions.

23. Dividend policy

Based on the currently expected cash flow generation of the Enlarged Group following Completion, the Directors intend to commence payment of an annual dividend. This is initially expected to be US$12.5 million, assuming appropriate business performance, from FY 2018 onwards (i.e. payable in 2019). The Directors may revise the Enlarged Group's dividend policy from time to time in line with the actual results and financial position of the Enlarged Group.

24. Taxation

Information regarding taxation is set out in paragraph 17 of Part 13 of this document. These details are intended as a general guide only to the current tax position in the United Kingdom regarding withholding taxes and is not intended to constitute personal tax advice for any person. Prospective investors are strongly advised to consult their own independent professional tax advisers regarding the tax consequences of purchasing and owning Ordinary Shares.

25. Share Options

The Company considers it essential that its Directors, Senior Managers and employees are appropriately incentivised to create future value for the Shareholders. This is relevant in the context of the Enlarged Group, whereby it will be important that key employees of the Seven Group who become part of the Enlarged Group are appropriately incentivised.

The Company currently has in place the Long-Term Incentive Plan and the Supplementary Plan (together the "**Existing Plans**"), further details on which are disclosed in paragraphs 4.2 and 4.3 of Part 13 of this document.

The Remuneration Committee have decided to grant no further awards under the Existing Plans given the material change in the Company's business. The vesting and hurdle conditions of the Existing Plans (details of which are disclosed in paragraphs 4.2 and 4.3 of Part 13 of this document) are in the Remuneration Committee's view too stretching to serve as a realistic incentive. Accordingly, it is proposed that, following completion of the Placing, these conditions be amended as follows:

- In the case of the awards granted under the Long-Term Incentive Plan:
  - the Hurdle Price (as is defined in paragraph 4.2.2 of Part 13 of this document be reduced from £1.68 to 42 pence per Ordinary Share (being a 20 per cent. premium to the Placing Price); and
  - the vesting date be amended to a period determined by the Remuneration and Nominations Committee; and
- In the case of the Supplementary Plan, the vesting condition of the Company's share price on any day equalling or exceeding £1.14 per Ordinary Share be amended to refer to a target share price of 42 pence per Ordinary Share (being a 20 per cent. premium to the Placing Price).

In addition to the proposed amendments to the Existing Plans referred to above, the Remuneration Committee intends to adopt one or more additional management and employee incentive schemes at some point following Re-Admission (the "**Additional Schemes**").

In order to facilitate the Additional Schemes, the Company has established the employee benefit trust (the "**EBT**"). The EBT shall subscribe for 42,624,837 New Ordinary Shares (the "**EBT Shares**") simultaneously with the allotment and issue of the Second Tranche Placing Shares at a subscription price per share equal to the nominal value of such shares (£0.001 per share). Savannah Petroleum 1 Limited, a wholly owned subsidiary of the Company, will provide a loan facility for this amount to the Trustee of the EBT. It has been agreed with the Trustee of the EBT that, with regard to any EBT Shares owned by the EBT: (i) subject to the Trustee's compliance with its obligations as a trustee and relevant legislation, the voting rights attaching to such shares shall be exercised in accordance with the instructions of the Board, and (ii) the Trustee will waive all rights to dividends on such shares.

At present, the Existing Plans permit the grant of awards over issued or unissued Ordinary Shares equal to, in aggregate, up to 15 per cent. of the Company's fully diluted share capital. This aggregate limit (applicable collectively to the Existing Plans and the Additional Schemes) will be reduced to 10 per cent. of the fully diluted share capital from time to time. As with the Existing Plans, it is intended that up to one half of the equity available under any Additional Schemes would be made available to the Chief Executive Officer.

The Remuneration and Nomination Committee intends to attach conditions to any awards granted under the Additional Schemes, which may include long-dated vesting criteria, key business metric KPIs and future share price performance conditions with reference to the Placing Price. Such conditions will be determined by the Remuneration and Nominations Committee in consultation with Savannah's Nominated Adviser. The Board acknowledges the possible requirement, in certain circumstances, to obtain a fair and reasonable opinion from the independent directors of the Company, in consultation with the Company's nominated adviser, with regard to any particular award to be granted under the Additional Schemes.

Further details of the Additional Schemes and any awards granted pursuant thereto will be announced in due course following completion of the Placing.

26. General Meeting

Set out at the end of this document is a notice convening a General Meeting to be held at the Hilton London Canary Wharf, Marsh Wall, London E14 9SH, at 3.00 p.m. on 8 January 2018 at which the following Resolutions will be proposed:

- Resolution 1 (a Transaction Resolution): subject to the passing of Resolutions 2 and 3, an ordinary resolution to approve the Transaction for the purposes of Rule 14 of the AIM Rules for Companies;
- Resolution 2 (a Transaction Resolution): subject to the passing of Resolution 3, an ordinary resolution to:
  - o authorise the Directors to allot the Second Tranche Placing Shares;
  - o authorise the Directors to allot the Consideration Shares;
  - o authorise the Directors to allot Ordinary Shares pursuant to the exercise of any or all of the Warrants;
  - o authorise the Directors to allot further Ordinary Shares representing up to 33 per cent. of the Further Enlarged Share Capital; and
  - o authorise the Directors to allot the EBT Shares.
- Resolution 3 (a Transaction Resolution): subject to the passing of Resolution 2, a special resolution to dis-apply statutory pre-emption rights in relation to the allotment of:
  - o the Second Tranche Placing Shares;
  - o the Consideration Shares;
  - o Ordinary Shares pursuant to the exercise of any or all of the Warrants;
  - o the EBT Shares; and
  - o further Ordinary Shares representing up to 20 per cent. of the Further Enlarged Share Capital.
- Resolution 4: an ordinary resolution to re-elect Andrew Knott as a director of the Company.
- Resolution 5: an ordinary resolution to re-elect Mark Iannotti as a director of the Company.
- Resolution 6: an ordinary resolution to re-elect Stephen Jenkins as a director of the Company.
- Resolution 7: an ordinary resolution to re-elect David Jamison as a director of the Company.
- Resolution 8: an ordinary resolution to re-elect Isatou Semega-Janneh as a director of the Company.
- Resolution 9: an ordinary resolution to re-elect David Clarkson as a director of the Company.
- Resolution 10: an ordinary resolution to re-elect Sir Stephen O'Brien as a director of the Company.
- Resolution 11: an ordinary resolution to re-elect Michael Wachtel as a director of the Company.
- Resolution 12: a special resolution to approve the purchase of the Company's own shares.

If Resolution 1 is not passed, the Acquisition will not proceed. If Resolutions 2 and 3 are not passed, the Transaction will not proceed, the Enlarged Group will not be formed and the Warrants attributable to the First Tranche Placing Shares will not be issued.

To be passed:

- Resolution 1 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 2 requires a simple majority of Shareholders voting in person or proxy to vote in favour;
- Resolution 3 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour;
- Each of Resolutions 4, 5, 6, 7, 8, 9, 10 and 11 requires a simple majority of Shareholders voting in person or proxy to vote in favour; and
- Resolution 12 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour.

27. Admission, settlement and dealings

Trading in the Existing Ordinary Shares is expected to recommence at 8.00 a.m. today. The First Tranche Placing Shares are expected to be admitted to trading on AIM at 8.00 a.m. 28 December 2017. Assuming the passing of the Resolutions 2 and 3 at the General Meeting and on the earlier of the SSNs accepting the Exchange Offer and receipt of the Scheme Approvals, the Second Tranche Placing Shares and the Consideration Shares are expected to be admitted to trading on AIM shortly thereafter.

Assuming the Implementation Agreement is agreed, entered into and becomes effective, the Accugas Transaction becomes effective, the Frontier Agreements are agreed, entered into and become effective, the earlier of acceptance of the Exchange Offer by the SSNs or the Seven Energy Court Resolutions are passed at the Seven Energy Court Meetings (if necessary), Scheme Approvals are obtained (if necessary), Ministerial Consent is received, NSEC Consent is received, creditors under the Accugas IV Facility Agreement, the WCF Agreement, the DSA Facility Agreement and the Promissory Note cooperate with the Transaction, the Accugas Waiver is received and the English High Court administration order in respect of SEIL is granted, the cancellation of the Company's existing quotation on AIM will become effective and Re-Admission will occur. The Company expects that Ministerial Consent and NSEC Consent will be received by mid-March 2018 and therefore Re-Admission of the Further Enlarged Share Capital is expected to occur by the end of March 2018.

In the event that the issue of the Second Tranche Placing Shares does not complete, the Company intends to use the monies raised pursuant to the issue of the First Tranche Placing Shares to fund its working capital requirements.

28. CREST

CREST is a paperless settlement system enabling securities to be evidenced otherwise than by a certificate and transferred otherwise than by written instrument in accordance with the CREST Regulations.

The Ordinary Shares are eligible for CREST settlement. Accordingly, following admission, settlement of transactions in the Ordinary Shares may take place within the CREST system if a Shareholder so wishes.

CREST is a voluntary system and Shareholders who wish to receive and retain share certificates are able to do so.

For more information concerning CREST, Shareholders should contact their stockbroker.

29. Risk factors and Additional Information

Your attention is drawn to the additional information set out in Parts 3 to 16 (inclusive) of this document. You are recommended to read all the information contained in this document and not just rely on the key or summarised information. In particular Shareholders should read in full the Risk Factors set out in Part 3 of this document.

The technical information contained in this document, which has been extracted from the Competent Person's Reports in Parts 11 and 12 of this document, has been reviewed and approved by LR and CGG, respectively. Both parties have consented to the inclusion of the technical information extracted from the Competent Person's Reports in this document in the form and context in which it appears.

30. Action to be taken

A Form of Proxy is enclosed with this document for use by Shareholders in connection with the General Meeting. Whether or not you intend to be present at the General Meeting, Shareholders are asked to complete, sign and return the Form of Proxy in accordance with the instructions printed thereon.

To be valid, completed Forms of Proxy must be received by the Company's Registrars, Computershare Investor Services PLC, The Pavilions, Bridgewater Road as soon as possible and in any event so as to arrive not later than 3.00 p.m. on 6 January 2018, being 48 hours before the time appointed for the holding of the General Meeting.

The completion and return of the Form of Proxy will not preclude Shareholders from attending the General Meeting and voting in person should they wish to do so. Accordingly, whether or not Shareholders intend to attend the General Meeting they are urged to complete and return the Form of Proxy as soon as possible.

31. Directors' recommendation and voting intention

The Directors consider that the Transaction is in the best interests of the Shareholders and the Company as a whole, and, accordingly, the Directors recommend that Shareholders vote in favour of the Resolutions to be proposed at the General Meeting, as they have irrevocably undertaken to do so in respect of their own beneficial holdings of 28,082,840 Ordinary Shares, representing approximately 10.2 per cent. of the Existing Ordinary Shares.

Shareholders should note that in the event the Resolutions are not approved, amongst other things, the Acquisition will not proceed and the Second Tranche Placing Shares will not be issued. If the Second Tranche Placing Shares are not issued, the Company will not receive the net proceeds from the issue of the Second Tranche Placing Shares.

In this scenario, the Company will only receive the net proceeds of the First Tranche Placing Shares, which, for the avoidance of doubt, are not conditional on the passing of the Resolutions. The Company would therefore require alternative sources of funds, to be able to both advance its Nigerien assets in the manner contemplated in this document and fund its ongoing working capital requirements. For this reason, the Company strongly encourages Shareholders to vote in favour of the Resolutions.

Yours faithfully,

Steve Jenkins
Non-Executive Chairman

PART 2

TRANSACTION OVERVIEW

1. Transaction Summary

1.1 The Company has been in discussions with Seven Energy and certain of its key creditors since the beginning of 2017 regarding the acquisition by the Company of:

1.1.1 a 40 per cent. participating interest (economic interest detailed in Part 7) in the Uquo Field, through the acquisition of SUGL;

1.1.2 a 62.5 per cent. equity interest in Universal, which holds a 51 per cent. participating interest in the Stubb Creek Field; and

1.1.3 in conjunction with private equity investors, Seven Energy's Accugas Midstream Business, a circa 260 km gas pipeline network and associated gas processing infrastructure in Nigeria, of which the Company will ultimately hold a 20 per cent. carried interest, via its shareholding in Accugas Holdco.

1.2 On 14 November 2017, the Company, the Seven Energy Group and certain of its key creditors entered into the Lock-up Agreement pursuant to which it was agreed to support and facilitate, subject to certain conditions, the Capital Restructuring and the Acquisition. The Lock-Up Agreement has since been amended by the Lock-Up Amendment Agreement – please refer to paragraph 4.3 of this Part 2.

1.3 The Company is currently undertaking discussions with Seven creditors to agree the Lock-Up Agreement which reflects the following terms. The total consideration payable by the Company for Seven Energy's interests in the Uquo Field and the Stubb Creek Field is approximately US$280 million and consists of:

1.3.1 approximately US$50 million in cash;

1.3.2 US$85 million in assumed debt; and

1.3.3 new Ordinary Shares with a value up to US$146.4 million based on the Placing Price (being 312,013,810 new Ordinary Shares).

1.4 The Transaction remains subject to a number of conditions and other requirements, principally the following:

1.4.1 shareholder approval at the General Meeting;

1.4.2 at least 75 per cent. of the Principal Amount of the SSNs (or such lesser proportion) as agreed by the parties to the Lock-Up Agreement continuing to be bound by the Lock-Up Agreement notwithstanding the withdrawal right contained in the Lock-Up Amendment Agreement (which may be exercised by holders of approximately 48 per cent of the SSNs – please refer to paragraph 4.3 of this Part 2);

1.4.3 the Implementation Agreement being agreed, entered into and becoming effective. Certain holders of the outstanding SSNs, the holder of the 10.50% Notes, the lenders under the First Bilateral Facility and the lenders under the Second Bilateral Facility have entered into the Lock-up Agreement and are expected to enter into the Implementation Agreement (other than SSN holders holding less than 4 per cent. of the principal amount of the SSNs). Those parties who have entered into the Lock-Up Agreement have agreed to use reasonable endeavours to support, facilitate and implement the Transaction as set out therein;

1.4.4 the Accugas Transaction becoming effective. It should be noted that the Company and the Investors have entered into a conditional investment agreement and agreed the terms of a shareholders' agreement to be put in place in connection with the Accugas Transaction. Please refer to paragraph 5.1 of Part 14 for further details;

1.4.5 the Exchange Offer being approved by 90 per cent. of the Principal Amount of the SSN holders or approval of the Seven Energy Court Resolutions at the Seven Energy Court Meetings. As mentioned above, certain holders of the outstanding SSNs have entered into the Lock-up Agreement. Those parties who have entered into the Lock-Up Agreement have agreed to use reasonable endeavours to support, facilitate and implement the Transaction as set out therein, including exercising any voting powers or rights available to such holders in favour of the

Transaction. This includes, where applicable, support for the schemes of arrangement which require, amongst other things, a majority in number representing at least 75 per cent. in value of the creditors present and voting either in person or by proxy at the creditors' meeting in order to become effective (see paragraph 6 of this Part 2 for further details regarding the scheme of arrangement process);

1.4.6 Scheme Approvals (i.e. only if the Exchange Offer does not proceed);

1.4.7 the Frontier Agreements being agreed, entered into and becoming effective. The Company is currently in discussions with Frontier is relation to the execution of certain new agreements in order to formalise the arrangements between: (i) Frontier and SUGL in relation to the Uquo JOA; (ii) Frontier and Accugas Limited in relation to the Uquo CPF; and (iii) the Uquo JV and Accguas in relation to the sale of gas to Accugas Limited. Frontier has sent notices of default to SUGL (pursuant to the Uquo JOA) and to Accugas Limited (pursuant to GSAs with the Uquo JV) in respect of various alleged breaches and is seeking approximately US$ 9.5 million of cash payment in relation to unpaid cash calls. It is intended that the Enlarged Group will settle at Completion any of such unpaid cash calls due to Frontier to the extent they remain unpaid at Completion as part of reaching an agreed remedy in respect of this default notice. (See paragraph 5 (Ongoing Negotiations) of this Part 2.);

1.4.8 co-operation of other creditors of the Seven Group. With regards to the Accugas IV Facility Agreement, the WCF Agreement, the DSA Facility Agreement and the Promissory Note, Savannah and the relevant creditors are at an advanced stage of negotiations to agree non-binding term sheets; however, formal approvals are still outstanding;

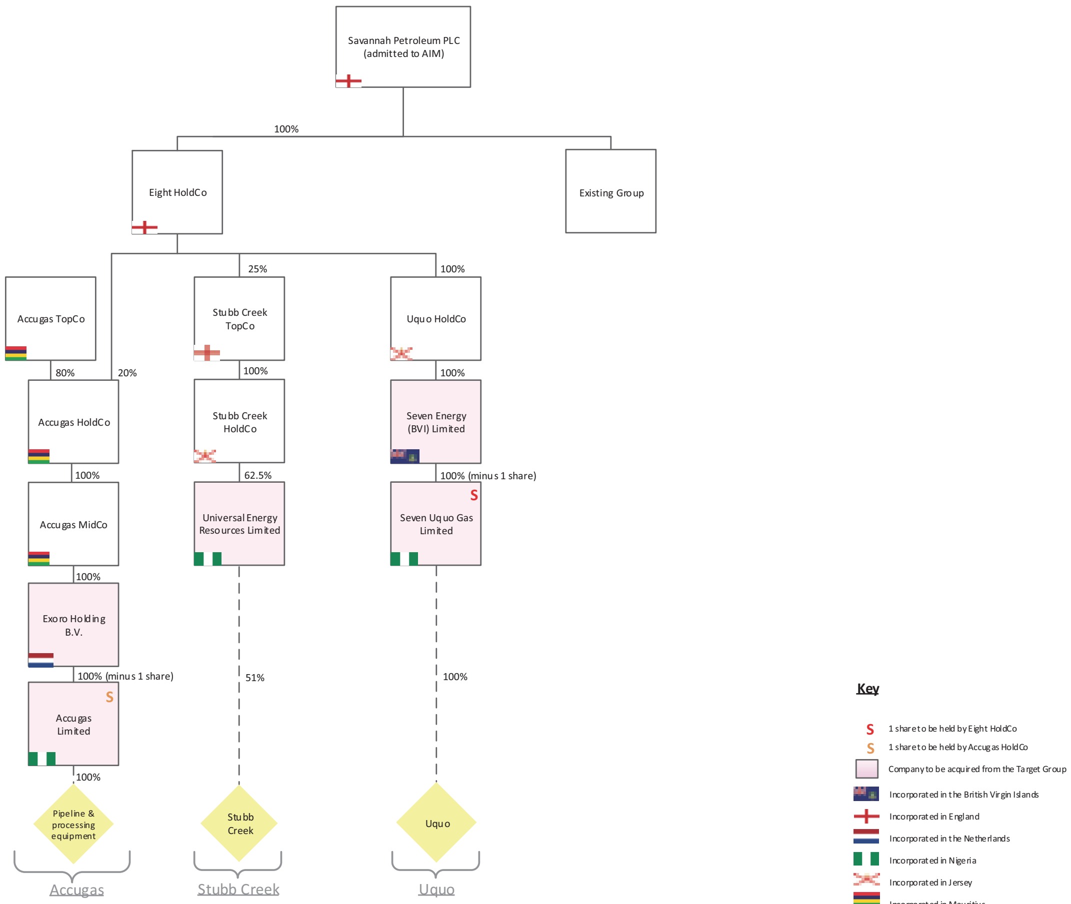
1.4.9 Ministerial Consent; and

1.4.10 NSEC Consent.

The Transaction remains subject to the parties agreeing and entering into definitive documentation.

1.5 A simplified structure chart of the Enlarged Group following Completion is shown below:

Figure 10 – Simplified Enlarged Group Structure Chart



2. The Capital Restructuring

2.1 The Seven Energy Group's existing indebtedness is US$887 million at 30 June 2017 and this is spread across eight separate facilities. The Capital Restructuring will involve a US$334 million reduction in the Seven Energy Group's existing indebtedness in exchange for a combination of new debt facilities, cash and newly issued Ordinary Shares. It has been agreed that around 85 per cent. of the reinstated debt will be repositioned in Accugas, with no recourse to the Company or any other assets of the Enlarged Group (save as set out in paragraph 2.3 below).

2.2 Under the terms of the Lock-up Agreement and other lock-in arrangements entered into by the Company, it has been agreed that, after Completion, the existing indebtedness in the Seven Energy Group will have been restructured as follows:

Figure 11 – Proposed Seven Energy Capital Restructuring (US$ million)

		Reinstated Debt (US$)(million)				
Facility	*Current Debt as at Last Practicable Date (US$)(m)*	*Accugas Holdco*	*Accugas Limited*	*Enlarged Group*	*Cash*	*Ordinary Shares**
Senior Secured Notes****	318	20	–	–	42.5 – 140**	109.5 – 0
10.50% Notes	107	15	–	85	–	–
First Bilateral Facility	25	20	–	–	–	–
Second Bilateral Facility	24	–	–	–	3.5	9.2
Accugas IV Facility Agreement***	375	–	375	–	–	–
WCF Agreement***	15	15	–	–	–	–
Promissory Note***	12	12	–	–	–	–
DSA Facility Agreement***	11	–	11	–	–	–
Total	887	82	386	85	46.0 – 143.5	9.2 – 118.7

* Subject to exercise of cash-out option (see paragraph 2.3.1)
** Subject to exercise of cash-out option
*** Expected terms based on non-binding agreed term sheets
**** Subject to confirmation of SSN participation level

2.3 In particular, as detailed in Figure 11:

2.3.1 The Capital Restructuring will see the holders of the SSNs receive, before Completion, up to US$42.5 million (minus a lock-up fee to be paid as an early bird consent fee pursuant to the Lock-up Agreement) in cash consideration and new Ordinary Shares having a value equal to US$109.5 million. The exact consideration will depend on the method of compromise (Exchange Offer or Scheme of Arrangement) and, in respect of an Exchange Offer, the level of SSNs tendered in that process. The Company has the option of cashing-out the equity portion of the consideration payable to the holders of the SSNs in the event the Placing is oversubscribed. The holders of the SSNs will also have the right to separately subscribe for new Ordinary Shares up to a value of US$26.7 million at a 20 per cent. discount (the "**SSN Shares**"). The holders of the SSNs who elect to subscribe for the SSN Shares will also be entitled to a *pro rata* share of the re-instated US$20 million Accugas Holdco senior secured notes due 2024 (the "**Accugas Senior Secured Notes**").

2.3.2 The Accugas Senior Secured Notes will be secured by share pledges over Accugas Holdco and Accugas Midco, and by all asset security granted by Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) by share security over, or asset security from, Accugas Limited. Cash interest will accrue on a pay-if-you-can basis at 6 per cent. per annum and paid-in-kind interest will accrue at 8 per cent. per annum. The Accugas Senior Secured Notes will permit dividends to the Company only under limited circumstances. The Accugas Senior

Secured Notes will be *pari passu* with the Private Bond Accugas Notes and the Reinstated First Bilateral Facility.

2.3.3 The holders of the 10.50 per cent. Notes will also receive a new issuance of US$15 million senior secured notes due 2026 (the "**Private Bond Accugas Notes**") in Accugas Holdco and secured by share pledges over Accugas Holdco and Accugas Midco, and by all asset security granted by Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) by share security over, or asset security from, Accugas Limited. Cash interest will accrue on a pay-if-you-can basis at 8 per cent. per annum and paid-in-kind interest will accrue at 10 per cent. per annum. The Private Bond Accugas Notes will permit dividends to the Company only under limited circumstances. The Private Bond Accugas Notes will be *pari passu* with the Accugas Senior Secured Notes and the Reinstated First Bilateral Facility (as defined below).

2.3.4 The First Bilateral Facility will be replaced by a US$20 million facility in Accugas Holdco (the "**Reinstated First Bilateral Facility**"). The Reinstated First Bilateral Facility will mature in 2024 and will be secured by share pledges over Accugas Holdco and Accugas Midco, and by all asset security granted by Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) by share security over, or asset security from, Accugas Limited. Cash interest will accrue on a pay-if-you-can basis at 6 per cent. per annum and paid-in-kind interest will accrue at 8 per cent. per annum. The Reinstated First Bilateral Facility will permit dividends to the Company only under limited circumstances. The Reinstated First Bilateral Facility will be *pari passu* with the Accugas Senior Secured Notes and the Private Bond Accugas Notes.

2.3.5 The majority of the outstanding amounts on the 10.50 per cent. Notes will be re-instated with a new issuance by SUGL of US$85 million senior secured notes due 2027 (the "**SUGL Notes**") to be secured against the interests Savannah is acquiring in the Uquo Field and the Stubb Creek Field. Cash interest will accrue at 8 per cent. per annum and paid-in-kind interest, payable in lieu of cash at the option of SUGL for the first two semi-annual periods only, will accrue at 10 per cent. per annum.

2.3.6 The Second Bilateral Facility will be replaced by a combination of cash and new Ordinary Shares.

2.4 Further descriptions of the proposed key terms of the reinstated debt is set out in paragraph 1 of Part 14 of this document.

3. The Accugas Transaction

3.1 The Company has agreed to purchase Accugas alongside the Investors.

3.2 The Investors will form a new company, Accugas Topco, to invest in the Accugas Midstream Business. A conditional investment agreement with the Company and has been entered into pursuant to which AIIM has agreed to invest at least US$45 million by way of shareholder loan and acquire an 80 per cent. interest in Accugas Limited (through its parent company, Accugas Holdco). AIIM is in discussion with one or more co-investors, including IDB Infrastructure Fund II, to increase this to US$60 million. This agreement will be novated to Eight Holdco and Accugas Topco once they have been formed. The Company will make a liquidity facility of US$20 million available to SEIL of which the third tranche of US$15 million, available from signing of the Implementation Agreement (subject to all conditions precedent to the liquidity facility having been satisfied) will be used to part fund certain costs incurred by the Seven Group as part of the Transaction. Eight Holdco will assume the liquidity facility as part of the Transaction and it will be amended and restated as a subordinated shareholder loan (such that it will be owed from Eight Holdco to the Company post-Completion). Additionally, prior to the Acquisition, a US$15 million receivable owing from Accugas Limited to SEIL will be assigned to Accugas Holdco in exchange for consideration of US$15 million which will be left outstanding. A loan agreement will be issued by Accugas Holdco to SEIL in respect of the US$15 million consideration left outstanding, to be in the same form as the shareholder loan of at least US$45 million and to rank pari passu, which Eight Holdco will acquire as part of the Transaction (leaving a US$15 million loan payable in Accugas Holdco owing to Eight Holdco post-Completion). Eight Holdco will acquire a 20 per cent. carried interest in Accugas Limited (also held through its parent company, Accugas Holdco).

3.3 As stipulated in the Investment Agreement, Accugas Topco and Eight Holdco have also agreed the form of a shareholders' agreement governing the management and control of Accugas Holdco which will be entered into on Completion. Accugas Topco has granted the Company the option to acquire a further 10 per cent. of the Accugas Midstream Business at a price equal to 10 per cent. of the total capital invested by the Accugas shareholders at the time the option is exercised, uplifted at an annualised rate of 10 per cent. The additional 10 per cent. of Accugas will not be carried by Accugas Topco. If the Company has exercised the option it must provide the proportion of any future funding by way of a shareholder loan, failing which Accugas Topco will provide the funding by way of a shareholder loan or subscribing for equity, provided that Accugas Topco's equity does not exceed 80 per cent.

3.4 The shareholders' agreement sets out the terms on which the parties will fund Accugas after the initial investment, with Accugas Topco providing shareholder loans and carrying the Company's interest. The Company and Accugas Topco have also agreed to provide standby funding to be drawn down in the event that Accugas is unable to service its cash interest payments in relation to the reinstated Accugas IV Facility Agreement due to revenue shortfall which is not provided for in the business plan on terms to be agreed.

3.5 The shareholders' agreement provides that Savannah shall appoint up to two of the five directors of Accugas Holdco and also contains typical reserved matters, which require the approval of shareholders holding 85 per cent. of the shares. The intention is to distribute 100 per cent. of the profits of the Accugas Midstream Business, subject to retaining a minimum cash balance after servicing third party debt. Distributions will first be used to repay shareholder loans, then distributed as dividends.

3.6 A summary of the key contractual provisions relating to the Accugas Transaction are set out in section 5 of Part 14 of this document.

4. The Lock-Up Agreement

4.1 On 14 November 2017, in order to support and facilitate the Transaction, the Company entered into the Lock-up Agreement with, among others, certain key debt holders of SEFL, in particular, certain holders of the SSNs, certain lenders under certain of SEFL's bilateral debt facilities and the holder of the 10.50 per cent. Notes, SEIL, SEFL and certain other members of the Seven Energy group (the "**Locked-up Parties**"). As at the date of this document, holders of approximately 90 per cent. by value of the SSNs are parties to the Lock-Up Agreement.

4.2 The Locked-up Parties agree, *inter alia*, to use reasonable endeavours to support, facilitate and implement the Transaction as set out therein, including exercising any voting powers or rights available to the Locked-up Parties in favour of the Transaction and not to accept, solicit or investigate any alternative to the Transaction. Pursuant to the Lock-up Agreement, the parties thereto agree to work together expeditiously and in good faith to agree the relevant documents in accordance with the agreed transaction and to finalise, execute and deliver those documents as soon as possible and, in any event, before the long-stop date of 31 January 2018 (extendable to 31 March 2018 by majority agreement).

4.3 Certain parties to the Lock-Up Agreement (including holders of approximately 42 per cent. by value of the SSNs) have agreed to enter into the Lock-Up Amendment Agreement. Amongst other things, this agreement:

– resized the consideration payable to the SSNs and the Second Bilateral Lender (amounts as set out in Figure 11 above);

– amended the transaction structure to allow the Company to purchase the SSNs for the consideration set out herein prior to Completion via an exchange offer or scheme of arrangement (extendable to 31 May in certain circumstances);

– extended the Long-Stop Date to 31 March 2018;

– approved all necessary changes to the steps plan to reflect the new transaction structure.

Pursuant to the Lock-Up Agreement these amendments are approved by Seven Energy, the Company and the Majority Consenting Parties, making it binding on all parties to the Lock-Up Agreement. Given the nature of these changes, notwithstanding that the amendment is valid and binding on all Participating SSN Noteholders (as defined in the Lock-Up Agreement), the Participating SSN Noteholders who have not signed the Lock-Up Amendment Agreement (i.e. holders of approximately

48 per cent. by value of the SSNs) will have until 5.00 p.m. on the 5 January 2018 to withdraw their accession to the Lock-Up Agreement. If Participating SSN Noteholders withdraw their accession to the Lock-Up Agreement, it could have an adverse impact on the timing and implementation of the Transaction.

4.4 The Lock-up Agreement is only terminable with the agreement of all parties, upon the occurrence of the long-stop date (when it automatically terminates) or by certain majorities or parties upon the occurrence of specific events outlined therein (see paragraph 1 of Part 14 for further details). There are also certain specified events which must have occurred, or be waived, before the parties can be forced to enter into the Implementation Agreement.

4.5 The undertakings in the Lock-up Agreement are subject to a specific performance clause and pursuant to this clause it is agreed by the parties that damages are not an adequate remedy for breach of those provisions. Therefore should a party fail to take a specified action, an application for specific performance of that action would be brought with the aim of compelling the defaulting party to comply with their obligations.

5. Ongoing Negotiations

With regards to the Accugas IV Facility Agreement, the WCF Agreement, the DSA Facility Agreement and the Promissory Note, Savannah and the relevant creditors are at an advanced stage of negotiations to agree non-binding term sheets; however, formal approvals are still outstanding.

Currently the relationship between Frontier and each of Accugas Limited and the Uquo JV is governed by a document suite which includes both executed and unexecuted contracts, the latter of which are operating on a conduct basis. Given the Seven Group's financial position, an unpaid cash call balance with Frontier currently exists in relation to the Uquo JV. Frontier has sent notices of default to SUGL (pursuant to the Uquo JOA) and to Accugas Limited (pursuant to GSAs with the Uquo JV) in respect of various alleged breaches and is seeking approximately US$ 9.5 million of cash payment in relation to unpaid cash calls. It is intended that the Enlarged Group will settle at Completion any of such unpaid cash calls due to Frontier to the extent they remain unpaid at Completion as part of reaching an agreed remedy in respect of this default notice and that the Frontier Agreements will be entered into as part of the Transaction.

The Company will, in the first instance, seek to effect the SSN element of the Capital Restructuring by way of an exchange offer (the "**Exchange Offer**"). The Company expects to offer holders of SSNs to exchange any and all outstanding SSNs upon the terms and conditions set forth in an exchange offer to commence early 2018. Once commenced, the Exchange Offer is expected to remain open for not less than 20 business days. At the option of the Parent and Purchaser, the scheme of arrangement described in paragraph 6 of this Part 2 may be implemented instead of the Exchange Offer. Otherwise, such scheme of arrangement will be implemented only if the Exchange Offer is not completed.

In consideration for tendering SSNs in the Exchange Offer, the Company expects to offer tendering holders of the SSNs a proportionate share of $42.5 million in cash consideration and $109.5 million in Ordinary Shares calculated at the Placing Price.

The Exchange Offer is expected to be conditional upon, among other things, the Company acquiring at least 90 per cent. in aggregate principal amount of the SSNs and shareholder approval at the General Meeting.

The settlement date of the Exchange Offer is expected to be in early February 2018, subject to the right of the Company to extend, re-open, amend and/or terminate the Exchange Offer in its discretion. The Exchange Offer will be open only to eligible investors in certain jurisdictions such as the United States and the EEA, including to not more than 150 persons that are not "qualified investors" in each EEA state.

In addition, either in connection with the Exchange Offer or following its completion, the Company expects the indenture in relation to the SSNs to be amended to facilitate completion of the Acquisition and the Capital Restructuring.

6. Scheme of Arrangement

6.1 If the Exchange Offer does not secure the requisite levels of consent or is abandoned due to the number of EEA retail investors, the SSN element of the Capital Restructuring will be effected by way of a court approved scheme of arrangement. It is expected that the scheme of arrangement will be commenced prior to the conclusion of the Exchange Offer, but will be abandoned if the Exchange Offer is successful. As a matter of English law, a scheme of arrangement is a statutory procedure under Part 26 of the English Companies Act 2006 whereby a company may make a compromise or arrangement with its members or creditors (or any class of them).

6.2 In order to implement the SSN element of the Capital Restructuring, SEFL will propose two schemes of arrangement. The first will be launched in the English High Court, the location of SEFL's centre of main interest, and the second will be launched in the BVI Commercial Court, its place of incorporation.

6.3 The schemes of arrangement will effect the agreed exchange for cash and Ordinary Shares between the holders of the SSNs and the Company and allow the holders of the SSNs to elect to participate in the re-instated debt in Accugas Holdco and be issued with new Ordinary Shares (or the cash-out option) in exchange for the original debt upon the Scheme of Arrangement becoming effective.

6.4 The scheme process in both jurisdictions will involve the following steps:

6.4.1 the issue of a practice statement letter to all creditors informing them of the first scheme of arrangement hearing;

6.4.2 court hearing at which the court will make orders to convene the creditors' meeting;

6.4.3 circulation of scheme document, explanatory statement and notice of creditors' meeting to creditors (electronic access);

6.4.4 creditors' meeting held where creditors vote (in person or by proxy) to approve or reject the scheme of arrangement;

6.4.5 chairman reports result of the creditors meeting to the court;

6.4.6 second court hearing to sanction the scheme of arrangement;

6.4.7 file scheme and court order sanctioning scheme with registrar of companies; and

6.4.8 scheme of arrangement becomes effective.

6.5 It is anticipated that all steps in the BVI scheme of arrangement will occur concurrently with or shortly after the equivalent step in the English scheme of arrangement.

6.6 In order for the schemes of arrangement to be passed, they must be approved by:

6.6.1 in England and Wales – a majority in number representing at least 75 per cent. in value of the creditors present and voting either in person or by proxy at the creditors' meeting and it must be subsequently sanctioned by the English High Court; and

6.6.2 in the BVI – a majority in number representing at least 75 per cent. in value of the creditors present and voting either in person or by proxy at the creditors' meeting and it must be subsequently sanctioned by the BVI Commercial Court.

6.7 In order for the creditors' meetings described above to be called, the English High Court must be satisfied that the scheme of arrangement has sufficient connection with the English jurisdiction and that it is therefore appropriate for it to exercise its powers. In this case the English High Court will be asked to accept jurisdiction on the basis that SEFL's centre of main interests i.e. where it administers its business from, is in England. The BVI Commercial Court will carry out a similar exercise when considering whether it has jurisdiction. It will have regard to the fact that SEFL is a BVI incorporated company when considering whether the BVI scheme of arrangement falls within its jurisdiction.

6.8 At the sanction hearing (see 6.4.6 above) the English and BVI courts will take into consideration a number of factors when deciding whether to exercise their discretion and sanction the schemes of arrangement. They will consider, amongst other things, whether the approval of the relevant scheme of arrangement is fair and reasonable, whether the creditors attending the creditors' meetings fairly represented the creditor class and acted in good faith, whether the correct process has been followed and whether the court order which they are being asked to grant will be effective in achieving its aim of restructuring the liabilities which are subject to the scheme of arrangement. As regards the effectiveness of a scheme of arrangement in particular, the courts will consider whether each of the jurisdictions which are connected with the affected liabilities will recognise the order it makes. As the SSNs are New York law governed liabilities, the English High Court may seek comfort that SEFL will, or is able to, avail itself of Chapter 15 recognition in the United States to ensure that a disgruntled noteholder cannot usurp the order of the English Court by making an application to recover its debt in the United States. It will also consider whether the scheme of arrangement will be recognised in Mauritius, Nigeria and Bermuda, being the jurisdictions in which the guarantees of the issues are incorporated.

6.9 The court may sanction the scheme as proposed, with amendments, or not at all. There can therefore be no guarantee that the court will sanction the schemes of arrangement and, if it does not, Completion will not occur.

7. Implementation Agreement

7.1 The Company and the Locked-up Parties have agreed that they will enter into an Implementation Agreement, which will document the legal terms and steps on which the Transaction will be implemented by the respective parties. The Implementation Agreement will need to be finally agreed and entered into by the Company and the Locked-up Parties before the Acquisition and the Capital Restructuring can be completed.

7.2 The Implementation Agreement will schedule, among other things:

7.2.1 the agreed purchase agreement regarding of the Company's acquisition of Seven Energy's interests in the Uquo Field and the Stubb Creek Field;

7.2.2 final finance documents on which it is proposed the Capital Restructuring will be effected;

7.2.3 intercreditor agreements relating to the finance documents; and

7.2.4 a purchase agreement regarding the acquisition of Exoro and its subsidiaries (including the operating company, Accugas Limited), pursuant to the Accugas Transaction.

7.3 In addition to scheduling various execution versions of the legal documents required to complete the Acquisition and Capital Restructuring (which will become effective pursuant to the terms of the Implementation Agreement), the Implementation Agreement will include provisions of support for the transaction, obligations to facilitate the transaction and limited termination rights.

7.4 The Implementation Agreement will set out, in detail, all the steps that need to occur to complete the Transaction, when those steps are to be taken, by whom and in what order. The completion mechanics of the deal will be a pre-agreed sequence of events that will commence once all conditions precedent to the Implementation Agreement have occurred. Conditions precedent are likely to include the termination and execution of the Frontier Agreements and the receipt of governmental and regulatory consents (see "Ministerial Consent" below).

7.5 A summary of the terms of the contractual agreements governing: (i) the Company's proposed acquisition of Seven Energy's interests in the Uquo Field and the Stubb Creek Field; and (ii) the Capital Restructuring, are set out in paragraph 1 of Part 14 of this document.

8. Shareholder Approval

8.1 As the Transaction constitutes a reverse takeover under the AIM Rules, it will require to be approved by Shareholders at a general meeting of the Company.

8.2 A general meeting of the Company has therefore been convened for 3.00 p.m. on 8 January 2018 and will be held at the Hilton London Canary Wharf, Marsh Wall, London E14 9SH. A copy of the notice of the General Meeting is set out in Appendix 2 of this document.

8.3 Completion is conditional on shareholders approving Resolutions 1 to 3 at the General Meeting. Resolutions 1 and 2 require a simple majority of Shareholders voting in person or proxy to vote in favour and Resolution 3 requires a majority of not less than 75 per cent. of Shareholders voting in person or by proxy to vote in favour.

8.4 To the extent any of Resolutions 1 to 3 are not passed, Completion will not take place and the Second Tranche Placing Shares will not be issued.

9. Ministerial Consent

9.1 Completion is conditional on Ministerial Consent being obtained.

9.2 Seven has notified the Department of Petroleum Resources of the proposed Acquisition and has received a "Letter of Authorisation to Proceed" with the same. This letter gives consent to Seven to submit a formal application for Ministerial Consent.

9.3 Immediately following the Company's entry into the Implementation Agreement (detailed below), the Company will apply to the DPR requesting the Minister's consent to the Acquisition.

9.4 The Minister's consent may only be granted where the Minister is satisfied that:

9.4.1 the Company is of good reputation;

9.4.2 the Company is in all other respects acceptable to the Federal Government of Nigeria; and

9.4.3 there is likely to be available to the Company sufficient technical knowledge, experience and financial resources to work each licence, lease or marginal field, which is being assigned.

9.5 Consideration of the application for consent would involve the DPR conducting due diligence on Savannah to establish the technical competence and the financial capability of Savannah within three months of the application.

9.6 The Company will also need to apply to NSEC for approval of the acquisition of 62.5 per cent. of the shares in Universal.

9.7 There can be no guarantee that Ministerial Consent or NSEC Consent will be obtained and, to the extent they are not obtained, Completion will not occur.

PART 3

RISK FACTORS

The investment detailed in this document may not be suitable for all of its recipients and involves a high degree of risk. Before making an investment decision, prospective investors are advised to consult a professional adviser authorised who specialises in advising on investments of the kind described in this document. Prospective investors should consider carefully whether an investment in the Company is suitable for them in the light of their personal circumstances and the financial resources available to them.

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.

In addition to the other relevant information set out in this document, the Directors consider that the following risk factors, which are not set out in any particular order of priority, magnitude or probability, are of particular relevance to the Enlarged Group's activities and to any investment in the Company. The risks and uncertainties described below are not the only ones the Enlarged Group faces. Additional risks and uncertainties of which the Enlarged Group is not aware or that the Enlarged Group currently believes are immaterial may also adversely affect the Enlarged Group's business, financial condition and results of operations. If any of the possible events described below were to occur, the Enlarged Group's business, results of operations, cash flows, financial condition and prospects could be materially and adversely affected. If that happens, the value of the Enlarged Group may diminish and you could lose all or part of your investment. Any one or more of these risk factors could have a materially adverse impact on the value of the Enlarged Group and should be taken into consideration when assessing the Company and whether to participate in the Placing.

There can be no certainty that the Enlarged Group will be able to implement successfully the strategy set out in this document. No representation is or can be made as to the future performance of the Enlarged Group and there can be no assurance that the Enlarged Group will achieve its objectives.

This document also contains forward looking statements that involve risks and uncertainties. The Enlarged Group's actual results may differ materially from those anticipated in these forward looking statements as a result of various factors, including the risks described below and elsewhere in this document. In general, investing in securities of companies in emerging market countries such as Nigeria and Niger involves certain risks not typically associated with investing in the securities of companies in more developed economies. To the extent the description in this section relates to government data or third party sources, such information has been extracted from official government publications or other third party sources and has not been independently verified by the Enlarged Group.

The risk factors have been grouped as follows:

1. Risks relating to the Transaction
2. Exploration, development and production risks associated with the Seven Assets
3. Exploration, appraisal, development and production risks associated with the Savannah PSCs
4. General exploration, development, production and business risks associated with the operations of the Enlarged Group
5. Risks relating to operating in Nigeria
6. Risks relating to operating in Niger
7. Risks relating to operating in emerging markets
8. Risks relating to the Ordinary Shares

1. Risks relating to the Transaction

1.1 *There is a risk that the Transaction will not be implemented on a timely basis or at all.*

Completion of the Transaction is conditional upon, among other things: (i) approval of the Resolutions at the General Meeting; (ii) the purchase of the SSNs (which is conditional on either (a) the Exchange Offer becoming effective or (b) approval of the Seven Energy Court Resolutions at the Seven Energy Court Meetings and the receipt of the Scheme Approvals); (iii) the Company entering into an appropriate implementation agreement to effect the Transaction; (iv) Ministerial Consent; (v) NSEC Consent; and (vi) the agreement and execution of the Frontier Agreements. There is a risk that the conditions of the Transaction will not be satisfied on a timely basis or at all. If such conditions are not satisfied, or, where applicable, not waived, the Transaction will not be implemented, the benefits expected to result from the Transaction will not be achieved and the market price of the Ordinary Shares may be affected.

In particular, the Company's entry into an appropriate implementation agreement is conditional on the Company being able to agree with, *inter alia*, the Locked-up Parties the terms on which the Transaction will be implemented and obtaining the Accugas Waiver. There also remains a risk that, prior to an implementation agreement being entered into, the Locked-up Parties could seek to re-negotiate the terms on which they have agreed to be locked-up and/or seek to exercise their respective rights to terminate the Lock-up Agreement in accordance with its terms (see Part 2 for further details).

Furthermore, the Capital Restructuring, like many restructurings of this nature, involves multiple stakeholders, some of which may, due to the financial distress being faced by the Seven Group, not be satisfied with the outcome and may seek to block or delay the Transaction. This includes the shareholders of Seven Group who, together with Seven, are party to a securityholder agreement which provides them with approval rights in relation to certain of the transaction steps forming part of the Capital Restructuring and Acquisition. Certain shareholders have not consented to the Transaction and therefore could potentially seek to injunct or block elements of the Transaction on the basis of breach of the securityholder agreement. However, certain key creditors of Seven, by signing the Lock-up Agreement, have indicated their support for the Capital Restructuring and the directors of Seven are mindful of their duty, given the financial circumstances of the Seven Group, to have regard to the interests of Seven's creditors and proceed with the Transaction. Further, Seven has been in communication with its shareholders over a number of months, consistently noting that in the circumstances its shareholders have no economic interest in the Seven Group and therefore would suffer no loss. Although the Company is satisfied that the legal and commercial position is such that the Transaction overrides any rights of the shareholders to prevent the implementation of the Transaction, there can be no assurance that there won't be any interference from any shareholders.

If the form of the Capital Restructuring changes, third party consents or waivers may be required pursuant to the Enlarged Group's contracts. If such consents or waivers are required and the relevant counterparties are not willing to provide consent or waivers or delay in providing consent or waivers, the Enlarged Group may suffer a loss of potential future revenue or completion of the Transaction may be delayed.

Frontier has sent notices of default to SUGL (pursuant to the Uquo JOA) and to Accugas Limited (pursuant to GSAs with the Uquo JV) in respect of various alleged breaches, including failure to pay amounts due to Frontier (see the 6th paragraph of risk factor 2.9 of page 53). Advanced drafts exist of the Frontier Agreements and a condition precedent of the Transaction is that they are entered into and it is intended that the Enlarged Group will settle at Completion any of such unpaid cash calls due to Frontier to the extent they remain unpaid at Completion as part of reaching an agreed remedy in respect of this default notice. As part of agreeing the Frontier Agreements there will be a need to obtain all necessary waivers in respect of any breaches, termination rights and related or consequential damages from the counterparties of those agreements and any other relevant agreements. There can be no certainty that the Frontier Agreements are entered into.

Additionally, the Ministerial Consent process involves a number of steps, including the DPR carrying out due diligence on the Company and the Transaction. Part of this diligence will focus on the structure of the marginal field ownership, see paragraph 2.7 "*The Enlarged Group's operations in marginal fields are subject to indigenous ownership restrictions*" for further details. Under the guidelines for obtaining Ministerial Consent, consent is granted on the basis of the technical and financial capability of the transferee. The Directors have no reason to believe that the Company will not meet such criteria, nonetheless, there can be no guarantee that the Government of Nigeria will consent to the Company becoming the holder of the Seven Assets. Although the Company expects to receive Ministerial Consent for the Transaction, there is a risk that governmental policy on oil and gas fields may change and Ministerial Consent will not be obtained on time or at all.

To the extent the Transaction is not implemented, the money raised pursuant to the First Tranche Placing Shares will not be returned to Shareholders and, instead, the Company will have broad discretion as to the use of proceeds of the Placing. In this scenario, the Company would require further funding to finance its proposed work programme in Niger and ongoing working capital.

1.2 ***Implementation of the Transaction requires the cooperation of certain other creditors of the Seven Group***

With regards to the Accugas IV Facility Agreement, the WCF Agreement, the DSA Facility Agreement and the Promissory Note, Savannah and the relevant creditors are at an advanced stage of negotiations to agree non-binding term sheets; however, formal approvals are still outstanding. There can be no assurance that the Company will be able to agree definitive agreements with such counterparties and, to the extent this does not occur, Completion will not take place.

1.3 ***The Enlarged Group will not receive the benefit of any contractual warranties or indemnities in respect of the Seven Assets.***

It is proposed that, on Completion, certain entities in the Seven Group will enter into asset sale and purchase agreements with certain members of the Existing Group to effect the transfer of the Seven Assets pursuant to the Transaction. Certain of the Seven Group entities will have first entered into administration and, as is customary for a transaction of this nature, it is anticipated that the administrators will not provide the Existing Group with any warranty or indemnity protection in the event that the Seven Group's title to the Seven Assets is defective in any respect. Although the transfer of certain of the Seven Assets will be effected by way of solvent sale by the relevant Seven Group entity, it is also anticipated that no warranty or indemnity protection will be provided in relation to such sale.

Although the Company has engaged its advisers to perform a due diligence review of the Seven Assets, such a review may not necessarily reveal all existing or potential problems or liabilities. For instance:

- the diligence carried out may not have revealed contracts with suppliers, customers, licensors, licensees, lessors, lenders, insurers and other business partners that have "change of control", consent triggers, termination rights or similar clauses that could require consents or waivers from the relevant counterparties;
- the information provided in connection with the due diligence carried out may not have been complete at the time it was given; and
- there may be unidentified disputes, environmental matters, regulatory enquiries, and health and safety issues that have not been identified.

In addition, the Company's review of the Seven Assets may not have permitted it to become sufficiently familiar with such assets to assess fully their deficiencies and capabilities.

Moreover, the Company will be acquiring the Seven Assets subject to all encumbrances and the claims of any third parties and, although the Company has carried out extensive legal and technical diligence on the Seven Assets, there remains a risk that unknown encumbrances, claims or other issues may become apparent in respect of the Seven Assets post-Completion and the Company may suffer a loss of potential future revenue and other rights and protections that are material to the business of the Enlarged Group.

1.4 ***If the Transaction is completed, the Enlarged Group may experience difficulties in integrating the existing businesses carried on by the Company and Seven Energy.***

The Existing Group and Seven operate and, until completion of the Transaction, will continue to operate, as two separate and independent businesses. The Transaction will lead to the integration of the two businesses, and the success of the Enlarged Group will depend, in part, on the effectiveness of the integration process and the ability of the Enlarged Group and the Directors to realise the anticipated advantages from combining the respective businesses.

In particular, there may be difficulties involved in combining the different capabilities required for the management of the Company's early stage assets and the broader mix of producing oil and gas assets and infrastructure assets held by Seven. The integration of the assets, organisations, systems and facilities of the Company and Seven, as well as the development of new systems and procedures for the Enlarged Group, requires the dedication of substantial management effort, time and resources which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. There can be no assurance that the Company will realise the potential benefits of the Transaction including, without limitation, recurring revenue from the Seven Assets to the extent and within the time frame currently contemplated by the Company.

The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect the Enlarged Group's ability to achieve the anticipated advantages of the Transaction.

Moreover, some of the potential challenges in combining the businesses may not become known until after completion of the Transaction, in particular due to the substantial increase in the scale of the combined operations and the number of projects which the Enlarged Group would operate. The geographical spread of the Enlarged Group's operations may make it more difficult to implement and impress upon local workforces the Enlarged Group's policies on matters such as health and safety and can present challenges in the effective supervision of sub-contracted employees. Uncertainty about the effects of the Transaction, including effects on employees, partners, contractors, regulators and customers may adversely affect the business and operations of the Enlarged Group. These uncertainties could cause customers, business partners, regulators and other parties that have business relationships with the Enlarged Group to defer the consummation of other transactions or other decisions concerning those businesses, or to seek to change existing business relationships.

1.5 ***Once the SSN element of the Capital Restructuring is effected, the Acquisition may subsequently not complete, resulting in the Company having issued shares and cash to the holders of the SSNs without ownership of the Seven Assets.***

There is a risk that, after the SSN element of the Capital Restructuring is effected, the Acquisition is subsequently not completed, which would result in the Company having issued shares and paid cash to the holders of the SSNs (as more particularly described in paragraph 2.3.1 of the Transaction Overview) in consideration for the transfer of the SSNs to the Company without ownership of the Seven Assets. This could occur if, subsequent to the SSN element of the Capital Restructuring being effected, either the Ministerial Consent or NSEC Consent is not obtained, the other creditors of the Seven Group do not execute the formal approvals needed to consummate the Transaction or any of the other conditions stated in Section 1.4 of Part 2 of this document do not occur.

1.6 ***The completion of the Exchange Offer is expected to be conditional upon, among other things, the Company acquiring at least 90 per cent. in aggregate principal amount of the SSNs in the Exchange Offer. If certain conditions are not satisfied, the Exchange Offer may not occur or may be delayed significantly.***

The consummation of the Exchange Offer is conditional upon the satisfaction and waiver of certain conditions. The Exchange Offer is expected to be conditional upon, among other things, the Company acquiring at least 90 per cent. in aggregate principal amount of the SSNs and shareholder approval at the General Meeting of the Company to be convened to approve, *inter alia*, the issue of the Consideration Shares and the Placing Shares. The Company also has the right to terminate or withdraw the Exchange Offer at any time and for any reason. If any one of these conditions is not satisfied, the Exchange Offer may not occur and, in the event that it does not occur, the Company will enter a scheme of arrangement as described in paragraph 7 of Part 2 of this Admission Document. If the court does not sanction the Scheme of Arrangement, or approves subject to conditions that the Company finds unacceptable, the Scheme of Arrangement will not become effective and this may have an adverse effect on the timing and/or implementation of the Transaction. See, in particular, *"There is a risk that the Exchange Offer and/or the schemes of arrangement will not become effective."* below.

1.7 ***Certain of the Company's or SEFL's creditors may attempt to challenge the progress or consummation of the Exchange Offer, which may delay the completion of, or result in the termination of, the Placing.***

The Company and/or SEFL may be subject to litigation initiated by holders of SSNs or other creditors to enjoin or otherwise prevent the settlement of the Exchange Offer or to attach assets in connection with any litigation in relation to the Exchange Offer. These creditors could argue that the Exchange Offer or the transactions related thereto violates their specific credit instruments. They could seek to call a default under their credit instruments or take judicial actions that may enjoin, impede, delay or result in the termination of the Placing or require the Company to pay damages in the event of an adverse judicial decision. While the Company intends to oppose any such litigation or other efforts, the Company cannot assure you of its success.

1.8 ***The Lock-Up Amendment Agreement provides SSN holders who are currently party to the Lock-Up Agreement with the ability to withdraw from the Lock-Up Agreement until 5.00 p.m., 5 January 2018***

The Lock-Up Amendment Agreement provides all SSN holders who are not signatory to it with the opportunity to withdraw their accession to the Lock-Up Agreement until 5.00 p.m on 5 January 2018. If an SSN holder withdraws their accession to the Lock-Up Agreement, they will no longer be bound by its terms. If one or more SSN holders choose to withdraw from the Lock-Up Agreement it could have an adverse impact on the timing and implementation of the Transaction.

1.9 ***There is a risk that the Exchange Offer and/or schemes of arrangement will not become effective.***

In order to implement part of the Transaction, SEFL will propose an exchange offer and/or schemes of arrangement in relation to its SSNs in the English High Court and the BVI Commercial Court. Whilst these processes follow a form and structure which is a common form for the market, there is a risk that they may not receive sufficient consents or, in the case of the schemes of arrangement, may not be approved.

The most common risk in relation to an exchange offer is that the prescribed acceptance rate, 90 per cent. by value in this case, is not obtained. If the requisite value of SSNs are not tendered then the exchange offer will fail. Any such failure may have an adverse effect on the timing and/or implementation of the Transaction. Some of the most common risks in relation to the effectiveness of schemes of arrangement are listed below.

Sufficient Connection

In order for the English High Court to accept jurisdiction in relation to SEFL's English scheme of arrangement, amongst other things, the court must be satisfied that the scheme of arrangement has sufficient connection with England. The Directors of SEFL believe, having taken legal advice, that SEFL's centre of main interest is in England and therefore that there will be sufficient connection in the opinion of the English High Court. Given that SEFL was incorporated in the British Virgin Islands, there is a risk that the English High Court will not agree with the assertion that SEFL's centre of main interest is in England and, to the extent it does so, this may have an adverse effect on the timing and/or the implementation of the Transaction.

Voting

In order for a scheme of arrangement to be approved a meeting of the affected creditors must vote on it and more than 50 per cent. in number representing not less than 75 per cent. in value of those creditors present and voting at such meetings must vote in favour of the relevant scheme of arrangement. If the requisite majorities of creditors do not vote in favour of either of the schemes of arrangement at the relevant creditors' meeting then that scheme of arrangement will be withdrawn. Any such withdrawal may have an adverse effect on the timing and/or the implementation of the Transaction.

Objections

Even if a scheme of arrangement is approved at the creditors' meeting, it is possible for a person with an interest in the relevant scheme of arrangement to object to the scheme of arrangement or to appeal the related court order. Such a person can attend or be represented at the sanction hearing in order to make representations that the scheme of arrangement should not be approved and to appeal against the granting of the court order. Therefore, it is possible that objections will be made against the granting of the court order and that any such objections may have an adverse effect on the timing and/or the implementation of the Transaction.

Sanction

In order for a scheme of arrangement to become effective, it must receive the sanction of the applicable court and the court order must be lodged with the relevant company register. A court will not sanction a scheme of arrangement unless, amongst other things, it is satisfied that the class of creditors has been properly constituted, the scheme proposed is fair and reasonable and, as a matter of discretion, the relevant court considers that it is proper to sanction the relevant scheme of arrangement. There can be no assurance that a court will sanction a scheme of arrangement.

If a court does not sanction a scheme of arrangement, or approves it subject to conditions or amendments which: (i) SEFL, the Company and other relevant parties deem unacceptable; or (ii) would have (directly or indirectly) a material adverse effect on the interests of any of the creditors affected by the relevant scheme of arrangement and such conditions or amendments are not approved by the relevant creditors, the scheme of arrangement will not become effective and this may have an adverse effect on the timing and/or the implementation of the Transaction.

1.10 ***The English scheme of arrangement may not be granted recognition and enforcement in the United States under chapter 15 of the U.S. Bankruptcy Code.***

In order to implement part of the Transaction, SEFL may be required to seek recognition and enforcement of the English scheme of arrangement in the United States through a petition and related applications under chapter 15 of the U.S. Bankruptcy Code. Recognition and enforcement of the English scheme of arrangement in the United States will require, among other things, (a) authorisation by the English High Court for a representative of the English scheme of arrangement to file a chapter 15 petition and seek relief in the United States, (b) a finding by the U.S. Bankruptcy Court that Seven Energy Finance Limited has its centre of main interests or an establishment in England, (c) findings by the U.S. Bankruptcy Court that the English scheme or arrangement constitutes a foreign proceeding, and (d) findings by the U.S. Bankruptcy Court that the relief requested in connection with the chapter 15 petition and related applications is not manifestly contrary to the public policy of the United States.

There are risks that the U.S. Bankruptcy Court will not grant recognition and enforcement of the English scheme of arrangement in the United States, or that recognition and enforcement may be delayed, or that an order granting recognition and enforcement may become subject to a stay and/or appeal. In each case, this may have an adverse effect on the timing and/or the implementation of the Transaction.

1.11 ***There is a risk that the English courts will not agree with the determination that SEIL's centre of main interest is in England.***

In order to implement part of the Transaction, SEIL will file for administration in the English High Court in order to complete the sale of certain assets to the Company. In order for the English High Court to allow the administration to proceed, amongst other things, the court must be satisfied that SEIL's centre of main interest is in England. The Directors of SEIL believe, having taken legal advice, that SEIL's centre of main interest is in England. However, given that SEIL was incorporated in Mauritius, there is a risk that the English High Court will not agree with the assertion that SEIL's centre of main interest is in England and, to the extent it does so, this may have an adverse effect on the timing and/or the implementation of the Transaction.

1.12 ***The Enlarged Group's Transaction related costs may exceed its expectations.***

The Enlarged Group's Transaction related costs may exceed its expectations. The Enlarged Group will incur a number of costs in relation to the Transaction, including execution, integration and post-Completion costs in order to successfully acquire the Seven Assets and combine the operations of the Existing Group and the Seven Assets. The actual costs of the transaction execution and integration process may exceed those estimated and there may be further additional and unforeseen expenses incurred in connection with the Transaction. In addition, the Company and Seven will incur legal, accounting, transaction fees and other costs relating to the Transaction, some of which are payable whether or not the Transaction completes.

1.13 ***The Enlarged Group will have increased indebtedness.***

Whilst the Directors believe that the Transaction will mitigate Seven's current liquidity issues by reducing aggregate indebtedness and extending the payment profile of interest payment obligations, following Completion, the Enlarged Group will have increased indebtedness and interest and debt repayment obligations. Such indebtedness will require the Enlarged Group to make annual repayment obligations, including required amortisation payments of US$6 million under the SUGL Notes with the first payment being due on 31 December 2019.

1.14 ***Certain figures included in the Nigeria CPR and the Niger CPR are modelled on certain assumptions that may turn out to be incorrect.***

The hydrocarbon reserve and resource estimates, and economic valuations associated with these estimates included in the Nigeria CPR and the Niger CPR are based upon certain assumptions, including, *inter alia*, contractual gas sales prices, future oil prices, geological and geophysical assumptions of the performance of the subsurface, demand, maintenance requirements and timing and size of future capital expenditure requirements. There can be no guarantee that these assumptions are correct. There are uncertainties inherent in estimating the quantity of reserves and resources, and in projecting future rates of production. Estimating the amount of hydrocarbon reserves and resources, and the expected cost to exploit these reserves and resources, is an interpretive process and, in addition, results of drilling, testing and production subsequent to the date of an estimate may result in material revisions to an estimate.

1.15 ***CGG, the author of the Niger CPR, used its own proprietary methodology to carry out "yet to find" analysis.***

CGG, as set out in the Niger CPR, has conducted a "yet-to-find" analysis on the Savannah PSCs. This is a proprietary methodology created by CGG and does not seek to reflect a replication of Savannah's work. The analysis estimates the quantity of oil that may ultimately be expected to be found on Savannah's licenses, based on previous discoveries made in the basin. The method calculates STOIIP per km2 for areas with similar characteristics, which are then adjusted and applied to the Savannah PSCs. It should be noted that these "yet-to-find" volumes are not linked to Savannah's planned exploration campaign; they are estimates of what could ultimately be discovered across the plays analysed, assuming a seismic and drilling campaign of similar density to that employed in the basin to date.

1.16 ***The Enlarged Group is required to adopt, prior to Completion, a number of financial procedures, processes and policies, including those documented as being in place at the Seven Group, which are more complex than the current processes followed by Savannah.***

Since the Company's AIM admission in August 2014, the Company has operated financial procedures, processes and policies that are consistent and suitable for an early stage AIM-quoted oil and gas exploration company. During the period between publication of this document and Completion, the Company intends to revise its financial procedures, processes and policies so that they are suitable, on Completion, for the operations and scale of the Enlarged Group. As part of the preparation for admission of the Further Enlarged Share Capital, the Board has approved key integration principles and developed a high level implementation plan. The Board also established an integration committee chaired by the CEO and overseen by the Audit Committee chairman to implement these revised procedures, processes and policies and monitor progress.

The nature of the Acquisition means that this revision will also involve the adoption of a number of the Seven Group's financial procedures, processes and policies, where appropriate for an AIM-quoted company of the size and complexity of the Enlarged Group. The provisions of the liquidity agreement entered into by Savannah with the Seven Group on 15 November 2017 have granted Savannah access to the Seven Group's financial information and finance personnel which will enable the Company to monitor Seven Group's performance in the period to Completion and allow for detailed planning for Completion. As such, the Company is heavily dependent on the continued support and employment of the Seven Group's finance team in this period up to Completion and thereafter. The Company has no prior experience of an integration of two businesses on this scale, which means certain integration processes may take longer and/or require more resources than expected.

The Company notes that due to the recent financial difficulties that the Seven Group has experienced and the subsequent reduction in the headcount of the finance team that resulted from this, not all of the financial procedures, processes and policies which Savannah intends to adopt have been followed in practice. The Company intends to address this situation prior to Completion through a careful review of resourcing and determine the most appropriate internal controls and procedures to put in place and make a plan to implement them. There is a risk of a significant diversion of management time and resources from the management of other aspects of the business.

The Company's current CFO has been appointed on an interim basis. The Board is committed to running a due nomination process to ensure that the candidate who undertakes this role in the longer term has the appropriate skills and experience commensurate with the Enlarged Group's requirements, which will be monitored by the Board on an ongoing basis.

1.17 ***There is a risk that the Liquidity Facility may be utilised by the Seven Group without the Transaction being implemented.***

The Company has entered into the Liquidity Facility in order to provide the Seven Group with additional finance for general corporate and working capital requirements in connection with the Transaction. The first tranche of US$1.5 million under the Liquidity Facility was pre-funded to a client account of legal counsel to the Seven Group and will be transferred to an account of the Seven Group upon the satisfaction or waiver of all conditions precedent under the Liquidity Facility. The second tranche of US$3.5 million under the Liquidity Facility also becomes available upon satisfaction or waiver of all conditions precedent to the Liquidity Facility. The third tranche of the remaining US$15 million under the Liquidity Facility will be available from signing of the Implementation Agreement (subject to all conditions precedent to the Liquidity Facility having been satisfied or waived), which is anticipated to occur no earlier than the date of the General Meeting. However, it is not a condition precedent under the Liquidity Facility that the Transaction is successfully implemented.

Therefore, it is possible that the Seven Group may draw (and the Company may apply the proceeds of the proposed equity fundraise in connection with the Transaction to fund) some or all of the US$20 million available under the Liquidity Facility without the Transaction being implemented.

In such circumstances where the Transaction has not been implemented, the relevant borrowers will be required to repay amounts advanced under the Liquidity Facility upon the earlier of (i) the date of termination of the Lock-Up Agreement in full with respect to all parties thereto (if the Implementation Agreement is not yet effective) or (ii) the date of termination of the Implementation Agreement in full with respect to all parties thereto (if the Implementation Agreement has become effective). Should the relevant borrowers not repay such amounts when due and payable, the Company will be entitled to call on the guarantees provided by certain members of the Seven Group under the Liquidity Facility.

In addition, the Company (together with certain other secured creditors of the Seven Group) may enforce the security provided over certain assets of the Seven Group, which are held on trust by The Law Debenture Trust Corporation P.L.C. as security agent for the benefit of certain secured creditors of the Seven Group pursuant to the terms of an intercreditor agreement dated 10 October 2014 (as amended and/or restated from time to time) between, inter alios, SEIL, SEFL and The Law Debenture Trust Corporation P.L.C. In accordance with the terms of such intercreditor agreement, the Company would be entitled to receive the proceeds of the enforcement of such security on a super senior basis. However, such enforcement may take substantial time to carry out (particularly if conflicting instructions are received by the security agent from other secured creditors of the Seven Group), may result in the incurrence of significant costs by the Company and may not ultimately lead to a full recovery by the Company of all amounts due and payable to it under the Liquidity Facility.

1.18 ***There is a risk that the Warrants attributable to the First Tranche Placing Shares may not be issued.***

The Warrants to which Placees will be entitled attributable to the First Tranche Placing Shares (the "**First Tranche Warrants**") will not be granted until after the issue of the Second Tranche Placing Shares and, as such, are conditional upon, amongst other things, the passing of the Resolutions. There is no guarantee that the Second Tranche Placing Shares will be issued and therefore the First Tranche Warrants may never be granted.

1.19 ***The Warrants may not be exercised in full or at all.***

In the event that all of the Warrants are exercised, the Directors expect to receive approximately US62.5 million of additional funds, which will be used to further advance the Company's Niger assets and for general corporate purposes. However, warrantholders are under no obligation to exercise their Warrants and, if they fail to do so, the Company will not receive any proceeds pursuant to the Warrants.

2. Exploration, development and production risks associated with the Seven Assets

2.1 ***The Enlarged Group's future gas revenues depend on certain key end users and such key end users may fail to fulfil their contractual obligations to Accugas Limited which in turn may fail to fulfil its contractual obligations to the Enlarged Group or the Enlarged Group could fail to obtain replacement customers.***

The Company will not enter into the Implementation Agreement unless the Uquo JV has been agreed and executed on terms satisfactory to the Company, a long term GSA with Accugas Limited for the sale of unprocessed gas in respect of the majority of its current gas reserves and resources in South Eastern Nigeria for the onward supply of processed gas by Accugas Limited under long-term GSAs with its three key customers, Calabar NIPP, Unicem and Ibom Power (the "**Consolidated Upstream GSA**"). The Consolidated Upstream GSA will contribute the vast majority of the Enlarged Group's future revenues and the Enlarged Group is consequently subject to a concentrated risk of counterparty default, which could lead to delayed payment (whether for delivered production volumes or otherwise).

Due to the Enlarged Group's reliance on Accugas Limited, the Enlarged Group's future gas revenues depend on Accugas Limited's receipt of payment from its downstream customers. Payments for the supply of gas to the Calabar NIPP are supported by the World Bank Partial Risk Guarantee. Accugas had experienced payment delays in respect of the supply of gas to the Calabar NIPP prior to the support of the World Bank Partial Risk Guarantee.

Similarly, payments for the supply of gas to the Ibom Power station are currently supported by a payment assurance facility from the Central Bank of Nigeria pursuant to the Nigerian Power Sector Recovery Program. There is no assurance that such programme will remain in place or continue to be funded. Accugas had experienced payment delays in respect of the supply of gas to the Ibom Power station prior to the adoption of this programme.

The Enlarged Group understands that the privatisation of the Calabar NIPP is being considered by the Nigerian government. In the situation that the privatisation proceeds, then the relevant PRG documentation envisages that Nigerian Bulk Electricity Trading plc ("**NBET**"), a Federal Government of Nigeria owned public liability company which is a party to the PRG documentation, will assume all of the obligations of NDPHC under those documents at the point in time at which privatisation occurs. If any of these obligations are not complied with or are disavowed by NBET, there is a risk that the effectiveness of the PRG will be compromised. The Enlarged Group would also need to continue to work with the Calabar NIPP under new privatised ownership and there can be no assurance that the Enlarged Group would be able to maintain good and constructive relationships with any new private owners.

Moreover, were Accugas Limited to become insolvent, the Enlarged Group may suffer business interruption and payment issues. Also, to the extent any of Accugas Limited's material downstream customers breach or disavow their respective contracts with Accugas Limited, there is a scarcity of potential new customers who might wish to contract with Accugas Limited for a supply of gas on a similar scale to Calabar NIPP, Unicem and Ibom Power.

Also, sales and transportation of the Enlarged Group's gas are dependent on the availability of pipeline, processing and other infrastructure facilities enabling its supply to customers and would require further infrastructure being installed to route that production output to alternative or additional end users. Any requirement to install new infrastructure in order to obtain an alternative or additional customer would require further capital expenditure by Accugas Limited that may not be available.

The occurrence of any of these events could have a material adverse effect on the Enlarged Group's business, future cash flows, results of operations, financial condition and prospects.

2.2 ***There can be no certainty in relation to future levels of growth in Nigerian domestic demand for gas.***

Whilst the Enlarged Group believes that utilisation of domestic gas in Nigeria will be important in solving Nigeria's shortage of domestic power, the expected growth in demand for domestic gas may be less or slower than anticipated. In particular, if the Nigeria government's Gas Master Plan is not successful in promoting the development and utilisation of gas in Nigeria and improving electric power generation and supply, or if the Nigerian government decides to amend its stated policy so as to move away from domestic gas as a key component of tackling Nigeria's shortage of domestic energy, expected growth in demand for domestic gas could be materially impacted.

2.3 ***The Enlarged Group's interests in Nigeria are concentrated on two oil and gas fields.***

The Enlarged Group's interests in Nigeria are concentrated on two oil and gas fields, namely the Uquo Field and the Stubb Creek Field. As a result, the Enlarged Group's success in Nigeria will be heavily reliant on it being able to continue to successfully exploit existing oil and/or natural gas reserves and/or maintaining valid legal title in those two fields. There can be no guarantee that the Enlarged Group can or will be able to, or that it will be commercially advantageous for the Enlarged Group to continue to exploit the Uquo Field and the Stubb Creek Field.

Furthermore, with both the Uquo Field and the Stubb Creek Field being located in South-East Nigeria, the Enlarged Group's revenues may be impacted by issues generally affecting oil and gas operations in the region. For further information, please see section 5, "*Risks related to operating in Nigeria*".

2.4 ***The Enlarged Group is reliant on the Uquo CPF, owned by Accugas Limited, and the Stubb Creek EPF to process crude oil and natural gas.***

Both the Enlarged Group and Accugas Limited are reliant on the Uquo CPF and the Stubb Creek EPF to process crude oil and natural gas. Any sudden loss of, or significant delay or interruption to, processing at the Uquo CPF or the Stubb Creek EPF or the transportation of crude oil and/or natural gas through the pipelines that the Enlarged Group and Accugas Limited use could result in an inability to utilise plant processing or pipeline capacity to meet contract requirements and/or deadlines. In particular, a significant interruption to crude oil and/or natural gas processing at the Uquo CPF or the Stubb Creek EPF could occur if any essential piece of equipment for which Accugas Limited or the Enlarged Group lacks a replacement should break down for a substantial period of time or if multiple breakdowns were to occur at the same time. Furthermore, there can be no assurance that Accugas Limited or the Enlarged Group will be able to find a replacement or arrange necessary repairs on a timely or cost-effective basis. In addition, Universal is awaiting the final permit to operate the Stubb Creek EPF; whilst this is expected to be an administrative issue, there remains a risk that the process of obtaining the permit may cause delays for the parties.

2.5 ***The Enlarged Group is reliant on third party owned or operated infrastructure for the transport of its oil and gas from the Uquo Field and the Stubb Creek Field to export terminals.***

The Enlarged Group is reliant on certain joint venture owned or third party operated infrastructure for its oil and gas operations, in particular the transportation of Uquo and Stubb Creek oil volumes sold through QIT for export. The Enlarged Group's oil volumes are stabilised through the FUN Manifold, which is jointly owned by the Uquo JV, the Stubb Creek JV and a third party JV. Although the Enlarged Group has an indirect interest in the FUN Manifold it does not have effective control. The Enlarged Group is subject to the terms of the FUN JOA.

Similarly, the Enlarged Group will be reliant on Accugas Limited's midstream infrastructure, which is operated by Accugas Limited, which, as part of the Accugas Transaction, the Enlarged Group will have a 20 per cent. interest.

The inadequacy or unavailability of such oil and gas pipeline capacity and infrastructure could require the Enlarged Group to shut-in wells, leading to the Enlarged Group being unable to realise revenues from sales of oil from those wells until suitable alternative transportation arrangements can be made.

2.6 ***The Enlarged Group is currently challenging renewal fees requested by the DPR.***

The DPR has requested licence renewal fees of US$1 million in respect of both the Uquo Field and the Stubb Creek Field, gross to such fields. The requested renewal fee has not yet been paid by the respective operators of such fields, Frontier and Universal. The Directors anticipate that the DPR will request the payment of these renewal fees by the relevant operators as part of the Acquisition. If the requested renewal fee is paid, the Directors anticipate that the DPR will confirm the Uquo Field and the Stubb Creek Field licences for a further term of 10 years in each case following payment. The Company intends to pay any renewal fees that are due. If it were not to do so, this could ultimately lead to a loss of licence.

2.7 ***The Enlarged Group's operations in marginal fields are subject to indigenous ownership restrictions.***

The Uquo Field and the Stubb Creek Field are subject to the rules and requirements of the Marginal Field Guidelines, which govern Nigeria's marginal field programme. The Marginal Field Guidelines provide, among other things, that marginal fields may only be awarded to, and operated by, indigenous companies that are "substantially Nigerian". Although the phrase "substantially Nigerian" is not defined in the Marginal Field Guidelines or any other Nigerian law, the DPR has historically taken the view that 51 per cent. Nigerian ultimate ownership of marginal fields is "substantially Nigerian", provided that such 51 per cent. ownership is maintained throughout its operation of the field.

Although the Directors believe that the current and post-Transaction ownership structures of both the Stubb Creek Field and the Uquo Field satisfy the "substantially Nigerian" requirement, to the extent DPR changes its policy in this regard or the ownership structure changes due to changes in the Enlarged Group or its joint venture partners in the relevant field there is a risk that the Company and its respective joint venture partners could be forced to relinquish their interest in these assets. The application for Ministerial Consent will include details of the ultimate ownership structure of the Uquo Field and the Stubb Creek Field and is expected to illustrate that the ownership structure in both cases complies with the Marginal Field Guidelines, however, there can be no assurances that Ministerial Consent will be granted or, if granted, finally conclusive on the matter for the future.

2.8 ***The Enlarged Group has not maintained decommissioning arrangements/security in respect of the Uquo Field and the Stubb Creek Field.***

Under the terms of the Enlarged Group's existing contractual arrangements with respect to the Uquo Field and the Stubb Creek Field, the Enlarged Group and its joint venture partners in such fields are obliged to maintain certain decommissioning arrangements/security in respect of potential future decommissioning liabilities. To date, these provisions have not been strictly enforced and such decommissioning arrangements/security arrangements have not been put in place. If a notice of breach was received in respect of these decommissioning arrangements/security arrangements then each of the contracts allow a 90 day period in order to remedy the breach, which may be achieved by making the relevant payments into escrow.

There is a risk that the Enlarged Group's contractual partners may seek to enforce such provisions against the Enlarged Group and its joint venture partners in the future. To the extent that they do so, this may have an adverse impact on the Enlarged Group's financial condition and prospects, as, although provision has been made for these costs, no escrow account or reserve has been maintained.

2.9 ***The Enlarged Group is subject to risks involving third party operators, partners and other project participants. Furthermore, disagreements with, or the exercise of termination rights by, any of the Enlarged Group's partners may result in delays or additional costs to the Enlarged Group.***

Whilst the Enlarged Group, through its subsidiary Universal, is operator of the Stubb Creek Field, the Uquo Field is operated by a third party operator, namely Frontier. Both the Enlarged Group and its partners are obliged to comply with the requirements of the applicable joint operating agreements, farm-out agreements and other arrangements governing their respective relationships. Co-operation and agreement among project participants on existing or future projects is important for the smooth operation and financial success of such projects and if one or more project participant were to fail to cooperate, it may delay or disrupt existing or future projects.

The joint operating agreement in respect of the Uquo Field, which is operated by Frontier with SUGL secondee support, requires decisions taken by the joint operating committee to be made on a unanimous basis, thereby requiring both the Enlarged Group and Frontier to vote in favour of decisions of the joint operating committee.

Whilst the Enlarged Group has certain rights under the Uquo Field TSA which provide it with the ability to influence and/or control management and/or operations, the Enlarged Group relies on Frontier to carry out the day-to-day management of operations of the Uquo Field. The Enlarged Group is also dependent on Frontier implementing the decisions that have been agreed among the participants of the Uquo Field and any mismanagement of the asset by Frontier may result in delays, disruptions or increased costs with respect to exploration, appraisal, development or production activities. The Enlarged Group also may disagree with actions proposed to be taken by Frontier and may be exposed to liability for actions taken by it. Whilst the terms of the operating agreement with respect to the Uquo Field imposes standards and requirements in relation to Frontier's activities and recourse for the Enlarged Group for breaches by Frontier of those agreements, there can be no assurance that Frontier will observe such standards or requirements.

Although the Stubb Creek Field is operated by Universal, the joint operating agreement in respect of the Stubb Creek Field requires decisions taken by the project management committee to be made jointly, thereby requiring both the Enlarged Group and Sinopec to vote in favour of key decisions of the project management committee (save for non-associated gas developments in respect of which Universal has the casting vote). Sinopec is currently required to provide 80 per cent. of funding in relation to crude oil and associated natural gas developments pursuant to the terms of the joint operating agreement in respect of the Stubb Creek Field. Given the financial impact any future crude oil and associated natural gas developments on the Stubb Creek Field would have on Sinopec, there is a risk that Sinopec may not vote in favour of oil development plans for the Stubb Creek Field.

The Enlarged Group may suffer unexpected costs or other losses if Frontier, Sinopec or any future partner does not meet its obligations. For example, other participants may experience financial or other difficulties or otherwise default in their obligations to meet capital or other funding obligations in relation to assets in which the Enlarged Group has interests, or the co-investors in Accugas may experience financial or other difficulties or otherwise default on their obligations to meet capital or other funding obligations in relation to Accugas and the midstream assets. Furthermore, any failure by a third party operator or the Enlarged Group to carry out its obligations with respect to a field could put the licence for that asset at risk. In addition, certain of the Enlarged Group's contractual arrangements may permit the Enlarged Group's partner(s) to terminate the relationship under certain circumstances. Any loss of a third party operator (and any resulting loss of the licence to the field operated by such operator) or partner could also impact the Enlarged Group's ability to develop the field in accordance with the development plans, or at all, which could impact oil and gas production at a given field and could lead to the Enlarged Group being unable to deliver gas to customers in accordance with its contractual obligations. This, in turn, could impact the revenues earned by the Enlarged Group with respect to the field.

Frontier has sent notices of default to SUGL (pursuant to the Uquo JOA) and to Accugas Limited (pursuant to GSAs with the Uquo JV) in respect of various alleged breaches, including failure to pay amounts due to Frontier. The consequences of such breaches, if not remedied, range from a curtailment of rights, termination of the relevant agreement (in one case immediate termination), and in the worst case termination of SUGL's interest in the licence of the Uquo Field. Advanced drafts exist of the Frontier Agreements and a condition precedent of the Transaction is that they are entered into and it is intended that the Enlarged Group will settle at Completion any of such unpaid cash calls due to Frontier to the extent they remain unpaid at Completion as part of reaching an agreed remedy in respect of this default notice.

Further, operators, partners and other project participants that own interests in assets in which the Enlarged Group has interests may have economic or business interests or objectives that are inconsistent or conflict with those of the Enlarged Group and may elect not to participate in certain activities relating to those assets or withhold their consent in circumstances when their consent is required, which may limit the ability of the Enlarged Group and other interest holders to explore, appraise or develop such assets as planned. For instance, the Enlarged Group will be heavily reliant on its joint venture partners in Accugas to ensure that the Enlarged Group's economic and trading objectives for Accugas Limited are met.

Whilst there have been instances of misalignment of interests or objectives in the past (relating, in particular, to the Seven Group's funding constraints and certain failures of downstream customers to meet their payment obligations) which were successfully resolved among the relevant parties, no assurance can be given that there will not be further instances of any such misalignment of interests or objectives nor that if they so arise they will not result in project delays, additional costs or disagreements.

Furthermore, from time to time, delays have occurred in the decision making process leading up to the development of fields and in the development of fields themselves as a result of the quality and experience of the contractors used by third party operators and partners and, in some cases, contractors were appointed that the Enlarged Group would not have wished to fulfil such roles. In circumstances where third party operators and partners have the right to appoint contractors rather than the Enlarged Group having such right, no assurance can be given that similar delays or quality issues will not occur in the future.

The occurrence of any of the above could have a material adverse effect on the Enlarged Group's business, results of operation, financial condition and prospects.

2.10 ***Drilling for and producing oil and gas are high-risk activities with many uncertainties which may result in the Enlarged Group's expenses increasing and projected cash flows decreasing and/or the Enlarged Group not meeting its obligations to Accugas Limited.***

The Enlarged Group's future success partially depends on its ability to develop the Uquo Field and the Stubb Creek Field in a timely and cost-effective manner in order to meet its obligations to Accugas Limited. As part of its strategy, the Enlarged Group intends to pursue the further development of its existing assets, which include undeveloped reserves and resources and prospective resources, and/or future opportunities to obtain or acquire further assets. This is expected to be achieved by further drilling and exploiting its existing fields, which the Directors believe will enable the Enlarged Group to grow its reserves and production levels. In particular, the aggregate volume of gas contracted to be sold under the Enlarged Group's long-term GSAs with Accugas Limited for ultimate downstream sale to Ibom Power, the Calabar NIPP and the Unicem cement plant, represents all of the discovered gas reserves produced from the Uquo Field and the Stubb Creek Field and may require the Enlarged Group to drill additional wells in the future at Stubb Creek in order to access gas reserves to continue to meet its supply obligations to Accugas Limited.

2.11 ***Actual or perceived failure by the Enlarged Group to address commodity and contractual issues may adversely affect the Enlarged Group.***

The price of oil produced from the Uquo Field and the Stubb Creek Field in accordance with the oil sales agreements relating to such production, is determined by reference to dated Brent quotations published in Platts (which generally moves in line with the prevailing global spot price for crude oil). Therefore, any decline in oil prices could result in a reduction in revenues or increased operating losses and could impair the Enlarged Group's ability to make planned capital expenditures and incur other costs necessary for the development of the Enlarged Group's fields.

The Enlarged Group's current gas production in the South East of Nigeria is predominantly contracted under long term GSAs, on the basis of a fixed price, which then may be subject to adjustment for inflation. Consequently, if the market price for gas increases beyond the levels set in such agreements, the Enlarged Group will not benefit from such increases and it could materially adversely affect the Enlarged Group's business, results of operations, financial condition and prospects.

Further, the inflation rate applied pursuant to the long-term GSAs may not reflect any actual increase in costs to which the Enlarged Group is subject. Thus, there is a risk that the Enlarged Group's costs in supplying gas will increase above inflation and that this will materially adversely affect the Enlarged Group's business, results of operations, financial condition and prospects.

2.12 ***Seven has in the past, and the Enlarged Group may in the future, attract spurious claims and media coverage and is therefore subject to reputation risk.***

Prominent businesses operating in Nigeria can attract significant attention from the Nigerian media, which can be of an adverse nature. Such media coverage can often be spurious and or politically motivated, put forward allegations which are unfounded due to the limited nature of the country's libel laws.

Seven has been subject to spurious litigation in the past and there can be no assurance that other negative publicity relating to the Enlarged Group will not arise and harm its reputation with its operating partners, other project participants, existing customers (some of whom are state-owned), prospective customers, regulators, suppliers, the wider Nigerian oil and gas industry, lenders and shareholders, regardless of the inaccuracy of, or lack of grounds for, any such negative publicity. Any such damage to the Enlarged Group's reputation could have a material adverse effect on its business, results of operations, financial condition and prospects and could have a material adverse effect on the prevailing market price of the Ordinary Shares.

The litigation proceedings set out in paragraph 14 of Part 13 of this documents have been commenced against the Seven entities that will form part of the Enlarged Group. The Directors, having taken legal advice, believe such claims are spurious and/or lack merit and should be defended. However, there remains a risk that such claims could harm the reputation of the Enlarged Group or result in a loss for the Enlarged Group in the event the claims were to succeed.

Other proceedings have been brought against SEPL, a Seven Group company which will not become part of the Enlarged Group. The claims pursuant to such proceedings amount to an aggregate of over Naira 29 billion (approximately US$62 million). Although these proceedings have not been brought in relation to companies within the Enlarged Group or in relation to assets which are being acquired as part of the Transaction, there is a residual risk that claimants may attempt to extend their claims to the Enlarged Group before or after completion of the Transaction.

2.13 ***There is a risk that the Enlarged Group could be held liable for successor liability for violations of Compliance Laws.***

It is possible that the Enlarged Group could be held liable for successor liability for violations of Compliance Laws, if such violations have been committed in the past by companies within the Seven Group, or by their employees, directors, representatives or agents, in relation to the Seven Assets. There have, in the past, been allegations and investigations into companies in the Seven Group which are not included in the Seven Assets and did not relate to the Seven Assets. It is the Company's belief that none of these investigations are ongoing in Nigeria and there are no other investigations ongoing in relation to companies in the Seven Group in any other jurisdiction. In addition, the Company's due diligence did not find any evidence of violations of Compliance Laws by the Seven Group or such persons or in relation to the Seven Assets. However, there remains a risk that the Company's due diligence may not have identified all issues which may have occurred over the life and in all aspects of the business of the Seven Group. The Company may also be negatively impacted if, in the future, allegations or investigations were to suggest violations of Compliance Laws had occurred in the past in relation to the Seven Group and/or the Seven Assets, whether or not such allegations or investigations were founded in fact.

3. Exploration, appraisal, development and production risks associated with the Savannah PSCs

3.1 ***The Existing Group is dependent on the Savannah PSCs.***

The Existing Group is currently dependent upon the Savannah PSCs and the grant of Exclusive Explorations Authorisations thereunder. Any adverse developments affecting the Savannah PSCs would have a material adverse effect on the Existing Group, its business, prospects, results of operations and financial condition.

3.2 ***The assets being the subject of the Savannah PSCs do not currently produce any positive cash flow.***

The Enlarged Group's assets in Niger are at an early stage of operations and do not produce any positive cash flow in Niger. The success of the Enlarged Group's interests in the Savannah PSCs will depend on, *inter alia*, the Enlarged Group's success in discovering and developing oil and/or natural gas, the Directors' ability to implement their strategy, generate cash flow from economically viable projects and access equity markets, Whilst the Directors are optimistic about the Enlarged Group's prospects in Niger, there is no certainty that sustainable revenue streams and sustainable profitability will be achieved. The Enlarged Group will not generate any material income from the Savannah PSCs until production has successfully commenced and in the meantime the Enlarged Group will continue to expend cash reserves on these assets.

3.3 ***Drilling for and producing oil and gas are high-risk activities with many uncertainties.***

A three well exploration drilling programme is planned by Savannah in Niger. Drilling is to be carried out by Great Wall Drilling Company Niger SARL, who have experience of drilling over 200 wells in the Agadem Rift Basin to date.

The Enlarged Group's current and planned expenditures on its Niger drilling programme may be subject to unexpected problems and delays, and the actual costs of this project may vary materially from the Enlarged Group's current estimates as a result of factors beyond its control, including, but not limited to, the following:

- competitive pressures on suppliers and contractors that provide products or services to the Enlarged Group in Niger;
- increases in the global prices of commodities or materials necessary for the completion of the Enlarged Group's current or anticipated exploration in Niger;
- Great Wall Drilling Company Niger SARL and other subcontractors failing to meet its contractual commitments to Savannah; and
- increases in salaries for labourers necessary to effect the Enlarged Group's drilling campaign in Niger.

The Enlarged Group may have limited operational and/or financial flexibility to deal with any such unexpected problems, costs and delays, in particular because of its current level of indebtedness. Any such unexpected problems, costs and delays could result in a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

3.4 ***There is a risk that a suitable export route for the Enlarged Group's oil and/or gas in Niger may not be available.***

There are currently no established oil and/or gas pipeline export routes in Niger. It is understood that study work has been commenced on possible export pipeline options, however, there is a significant risk that a suitable pipeline export route will not have been constructed by the time that Savannah seeks to achieve first oil in Niger.

To the extent that a suitable pipeline export route does not exist by the time Savannah seeks to achieve first oil in Niger, there is a risk that the Company will need to plan, fund and develop the necessary infrastructure by itself, which will involve significant cost.

As discussed in Part 15, under the terms of the Niger PSCs and the Petroleum Code of Niger, a framework for access to third party infrastructure has been established in the Company's favour. However, a residual risk exists that despite these provisions, there may be insufficient capacity to cater for all of Savannah's planned production volumes and/or the relevant legislation is not followed by the relevant parties.

Savannah has previously considered a trucking export option to enable an early production solution for any potential discoveries in the Niger PSC areas. Such a commercialisation option has not historically been conducted in Niger and is not currently believed to be under consideration by other operators in country. A risk exists that this option may not ultimately prove to be economically feasible.

3.5 ***The Enlarged Group is at risk of incurring financial penalties if it fails to meet the minimum work programme on the Savannah PSCs.***

A summary of the minimum work programme for both the R1/R2 PSC and R3/R4 PSC is set out in Part 8 of this document. As previously disclosed, the Company intends to use part of the proceeds of the Placing to fund the drilling of wells in order to meet the majority of the minimum work commitments on the Savannah PSCs. It is intended that part of the proceeds from the potential investment into the Company by the investment group including ASMA Capital Partners B.S.C.(c) (the "Proposed Investment"), as announced on 18 December 2017, will be used to satisfy the balance of the minimum work commitments on the R1/R2 PSC, being the acquisition of 500 square kilometres of 3D seismic data.

However, there is no guarantee that the Proposed Investment will materialise (see paragraph 1 of Part 1 of this document for further information) and in the event it does not, and the Company is unable to source alternative financing, the Enlarged Group will fail to satisfy its minimum work programme obligation in respect of the R1/R2 PSC, including the acquisition of the requisite 3D seismic, and therefore may be subject to a monetary penalty.

For instance, a penalty of: (i) US$1,000,000 will apply for each well not drilled; (ii) US$800 will apply for each kilometre of 2D seismic profiles not acquired, processed or integrated; and (iii) US$2,500 will apply for each square kilometre of 3D seismic profiles not acquired, processed or interpreted.

3.6 ***Niger is landlocked and this can create political and economic hurdles.***

Historically, being landlocked has been disadvantageous to a country's development. Being landlocked cuts a nation off from important sea resources and direct access to seaborne trade. In particular, materials and equipment must be brought by air or via land and/or sea routes through other countries. Therefore landlocked developing countries have significantly higher costs of international cargo transportation compared to coastal developing countries (according to the United Nations). Longer distance transportation increases the risk of confiscation, theft or other loss or damage, delays due to poor infrastructure, adverse weather or other conditions, duties, taxes or other unanticipated expenses. Being landlocked could therefore make it more difficult and more expensive for the Company to put the necessary resources and infrastructure in place to effectively exploit the Savannah PSCs as compared to if they were located in non-landlocked country.

3.7 ***The Existing Group conducts most of its operations through its subsidiary, Savannah Niger, which is located outside of the United Kingdom.***

The success of the Existing Group in the near term will be dependent on distributions from the Company and its financing subsidiaries to Savannah Niger in order that it may meet its obligations. At the point of production commencement, the ability of Savannah Niger to make payments to the Company may be constrained by, among other things, the level of taxation, particularly in relation to corporate profits and withholding taxes, in Niger, and the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated.

4. General exploration, development, production and business risks associated with the operations of the Enlarged Group

4.1 ***Drilling for and producing oil and gas are high-risk activities with many uncertainties which may result in the Enlarged Group's expenses increasing and projected cash flows decreasing and/or the Enlarged Group not achieving its planned production targets.***

The Enlarged Group's future success partially depends on its ability to develop its existing project inventory in a timely and cost-effective manner and achieve its production targets. As part of its strategy, the Enlarged Group intends to pursue the further development of its existing assets, which include undeveloped reserves and resources and prospective resources. This is expected to be achieved by drilling and exploiting its existing fields, which the Directors believe will enable the Enlarged Group to grow its reserves and production levels.

The Enlarged Group's decisions to purchase, explore, develop or otherwise exploit prospects or fields will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The costs of drilling, completing, equipping and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditure are a common risk that can make a particular project uneconomical.

Further, the Enlarged Group may be required to curtail, delay, suspend or cancel drilling operations and production because of a variety of operational and economic factors, which could, among other things, impact the Enlarged Group's ability to meet its gas supply obligations under its long-term GSAs. Such operational and economic factors could include the following:

- delays imposed by, or resulting from, compliance with regulatory and/or contractual requirements;
- natural catastrophes, fires and explosions;
- pressure or irregularities in geological formations;
- premature declines in reservoirs;
- blowouts, uncontrolled flows of oil, gas or well fluids;
- shortages of, or delays in obtaining, equipment and qualified personnel;
- pollution and other environmental risks;
- shortages or delays in the availability of drilling rigs and/or transport and the delivery of equipment;
- equipment failures or accidents;
- adverse weather conditions;
- security concerns or incidents;
- reductions in oil and gas prices (other than in circumstances where such drilling operations are required in connection with the obligations of the Enlarged Group pursuant to the terms of any long-term GSA which contains a fixed minimum price);
- surface access restrictions;
- access to and/or land ownership restrictions;
- lease problems; and
- limitations in the market for oil and gas.

Any of these circumstances, which, among other things, would have an impact on the Enlarged Group's ability to meet its gas supply obligations under its long-term GSAs, may have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

4.2 ***Current reserves, resources and forward production data in this Admission Document are estimates only and are inherently uncertain as they depend on many assumptions that may turn out to be inaccurate.***

Unless stated otherwise, the hydrocarbon reserves and resources and forward production data set forth in this Admission Document have been extracted without material adjustment from the Niger CPR and the Nigeria CPR set out in Parts 11 and 12 of this document.

The process of estimating oil and gas reserves and resources is complex and requires the interpretation of available technical data and many estimates, including estimates based upon assumptions relating to economic factors. Estimating underground accumulations of oil and gas is a subjective process which is inherently uncertain as they cannot be measured in an exact manner and different engineers may make different estimates of reserves and resources based upon the same data. In order to prepare estimates, production rates and timing of development expenditures must be projected and available geological, geophysical, production and engineering data and, where applicable, drilling results analysed. The extent, quality and reliability of this data can vary.

Estimates of the value and quantity of economically recoverable oil and gas reserves and resources, and consequently the rates of production and net present value of future cash flows realised from those reserves and resources, necessarily depend upon a number of variables and assumptions, including:

- historical production from the area compared with production from other comparable producing areas;
- interpretation of geological and geophysical data;
- assumed effects of regulations adopted by governmental agencies;
- assumptions concerning future oil and gas prices;
- availability and application of new technologies;
- assumptions regarding fiscal regime, tax and royalties;
- the expiry of oil and gas licences;
- new discoveries and extensions of existing fields as well as the application of improved recovery techniques;
- the level of capital expenditures that a given producer is willing or able to make at any given time; and
- assumptions concerning future operating costs, taxes and/or royalties on the extraction of commercial minerals, development costs and workover and remedial costs.

As estimates of reserves and resources are subjective, each of the following items may differ materially from those assumed in estimating the Enlarged Group's reserves and resources:

- quantities and qualities of oil and gas that are ultimately recovered;
- production profile of the oil and gas that are ultimately recovered;
- production and operating costs incurred;
- amount and timing of additional exploration and development expenditures; and
- future oil and gas sales prices.

The reserves and resources and forward production data contained in this Admission Document are estimates only and should not be construed as representing exact quantities. Reserves and resources estimates contained in this Admission Document are based on production data, prices, costs, ownership, geophysical, geological and engineering data and other information assembled by the Enlarged Group (with assistance from other operators). The estimates may prove to be incorrect and potential investors should not place undue reliance on the forward-looking statements contained herein (including data included in or extracted from the Nigeria CPR and the Niger CPR and whether expressed to have been certified by LR Senergy or CGG, respectively) concerning the Enlarged Group's reserves and resources or production levels.

Exploration drilling, interpretation and testing and production after the date of the estimates may require substantial upward or downward revisions in the Enlarged Group's reserves or resources data and estimates. Furthermore, different reservoir engineers may make different estimates of reserves, resources and cash flows based on the same available data. Actual production, oil and gas prices, revenues, royalties, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves and resources will most likely vary from estimates, and such variances may be material. The estimates also assume that the future development of the Enlarged Group's fields and the future marketability of the Enlarged Group's oil and gas will be similar to past development and marketability, that the Enlarged Group's assumptions as to its capital expenditure and operating costs are accurate and that the capital expenditure strategy of the Enlarged Group is successfully implemented by it. There can be no assurance that the actual capital expenditure will not vary significantly from current estimates or that the Enlarged Group will be able to implement its capital expenditure strategy to the timetable currently envisaged. If the assumptions upon which the estimates of the Enlarged Group's hydrocarbon reserves or resources have been based prove to be incorrect, the Enlarged Group or the operators of assets in which the Enlarged Group holds interests may be unable to recover and produce the estimated levels or quality of hydrocarbons set out in this Admission Document which could, in turn, prevent the Enlarged Group from complying with its gas supply obligations under its long-term GSAs, and the Enlarged Group's business, results of operations, financial condition and prospects could be materially adversely affected. In addition, the estimation of reserves and resources may also change because of acquisitions and disposals, new discoveries and estimations of existing fields as well as the application of improved recovery techniques.

4.3 ***Without the addition of reserves and resources through exploration, acquisition or development activities, the Enlarged Group's future reserves and resources and production will decline.***

Unless the Enlarged Group conducts successful development, exploitation and exploration activities or acquires assets containing additional reserves and resources or prospects, its reserves and resources will decline over time as reserves are depleted by production. Producing oil and gas reservoirs are generally characterised by declining production rates that vary depending upon reservoir characteristics and other factors. The Enlarged Group's future oil and gas reserves and production, and therefore its future cash flow and results of operations, are highly dependent on its success in efficiently developing and exploiting its current reserves and resources and economically finding or acquiring additional recoverable reserves and resources. The value of the Ordinary Shares and the Enlarged Group's ability to raise capital could be adversely impacted if it is unable to replace reserves and resources that are depleted by production. No assurance can be given that the Enlarged Group will be able to develop, exploit, find or acquire on appropriate terms sufficient additional reserves and resources to replace its future production and any such failure could lead to a decline in the Enlarged Group's reserves and production which could materially adversely affect the Enlarged Group's business, results of operations, financial condition and prospects.

4.4 ***Significantly increasing reserves and production requires significant capital expenditures and may require additional funding.***

The Enlarged Group's business requires significant capital expenditures for appraisal and development and, in the longer term, the Enlarged Group may need additional financing to fund its future exploration, development, acquisition and/or construction plans beyond its current committed and planned expenditures.

In the short-to-medium-term, the Enlarged Group intends to fund its planned capital expenditures from part of the proceeds of the Placing received by it, cash flows generated by the Enlarged Group's operations and from existing credit facilities. There can be no assurance that the Enlarged Group will be able to generate or raise sufficient funds to meet its capital expenditures in the longer term, or to do so at a reasonable cost. Moreover, in circumstances where such funding is not available, the Enlarged Group may be required to amend its appraisal, development and other capital expenditure plans.

The Enlarged Group's ability to arrange future financing, and the cost of financing generally, will depend on many factors, including:

- political, economic and capital markets conditions generally and, in particular, the non-investment grade debt market;
- commodity prices;
- investor confidence in the oil and gas industry in Nigeria, Niger and in the Enlarged Group;
- the business performance of the Enlarged Group;
- regulatory developments including provisions of tax and securities laws that are conducive to raising capital; and
- credit available from banks and other lenders.

Furthermore, any additional debt financing may involve re-financing costs or penalties or restrictive covenants and ratios that could limit or affect the Enlarged Group's operational flexibility. If additional funds are raised by issuing new Ordinary Shares, existing holders of Ordinary Shares may be diluted.

The Enlarged Group's inability in the longer term to procure sufficient financing could adversely affect its ability to expand its business and meet its production targets, may result in the Enlarged Group facing unexpected costs and delays in relation to the implementation of its project development and/or construction plans or may result in an inability to implement its plans as currently contemplated, and, if the reductions in financing levels are severe enough, they could adversely affect the Enlarged Group's ability to maintain its production at current levels.

Any of the foregoing could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

4.5 ***Any appraisal and development activities, which are typically carried out following the discovery of oil and gas, may require further funding or further licences and may not result in economically viable production.***

The results of any appraisal of oil and gas discoveries are uncertain and the appraisal and development activities of the Enlarged Group may require additional funding if the Enlarged Group decides to appraise and develop a discovery further. No assurance can be given, however, that any such expenditure will result in the discovery of commercially recoverable oil or gas.

Appraisal and development activities may require obtaining additional permits and consents. These may be subject to delay or onerous requirements by reason of governmental, regional or local consultation, approvals or other considerations or requirements.

The success of the Enlarged Group's appraisal and development operations depends on the Enlarged Group's ability to find and commercially exploit discoveries of oil and gas, including its ability to acquire land on which to build pipelines, processing plants and other equipment in a timely and cost-effective manner. The failure of the Enlarged Group to succeed in these endeavours may mean that the Enlarged Group may not be able to make a return on its investment.

Any of the above could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

4.6 ***Contingent Resources and Prospective Resources may not be commercially productive in the short or medium term.***

Unless stated otherwise, the Contingent Resources and Prospective Resources data set forth in this Admission Document has been extracted without material adjustment from the Nigeria CPR and Niger CPR set out in this Admission Document, which have been prepared by LR and CGG, respectively in accordance with the PRMS Standards. Additional uncertainties exist with respect to the estimation of Contingent Resources and Prospective Resources in addition to those that apply to reserves. Contingent Resources are those quantities of resources estimated, as of 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 currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to assess commerciality. Prospective Resources are those quantities of resources estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Development of Contingent Resources and Prospective Resources, if undertaken, may involve considerable expense, and may not result in the discovery of hydrocarbons in commercially viable quantities. The probability that Contingent Resources and Prospective Resources will be economically recoverable is considerably lower than that for proved, probable and possible reserves. Volumes and values associated with Contingent Resources and Prospective Resources should be considered highly speculative and there can be no assurance that the Enlarged Group will be able to develop these resources commercially.

4.7 ***Oil prices are volatile and could be subject to a substantial or extended decline.***

Historically, oil prices have been highly volatile and are likely to continue to be volatile in the future. Oil prices depend on a variety of factors beyond the Enlarged Group's control, including, but not limited to:

- global supply of, and demand for, oil and expectations regarding future supply and demand;
- costs of exploring for, developing and producing oil, together with commodity processing, gathering and transportation availability, and the availability of refining capacity;
- the ability of the members of OPEC and other oil producing nations to agree to and maintain oil prices and production controls;
- governmental regulations and taxes;
- discovery, availability and increased use of gas as an energy source;
- discovery, availability and increased use of U.S. shale oil and gas reserves;
- prices of, demand for and availability of alternative fuel sources (for example, hydro or other "green" forms of energy);
- weather conditions and natural disasters;
- political conditions or hostilities or acts of terrorism in oil producing regions;
- technological advances affecting energy consumption;
- currency valuations and fluctuations, particularly of the US dollar; and
- worldwide economic conditions and geopolitical events.

The Enlarged Group's profitability is determined, in large part, by the difference between the revenue it receives for the oil and gas that it produces and the sum of its operating costs, royalty costs, taxation costs and the costs it incurs in transporting and selling its oil and gas. Therefore, lower market prices for oil and gas may reduce the amount of oil and gas that the Enlarged Group can produce economically or may reduce the economic viability of the production levels of specific wells or of projects planned or in development to the extent that production costs exceed anticipated revenue from such production.

4.8 ***In the future, the Enlarged Group may be unable to make attractive acquisitions or integrate acquired companies and any acquisitions may prove to be worth less than the Enlarged Group paid.***

The Enlarged Group's strategy includes increasing its oil and gas reserves and resources through acquisitions of interests in further oil and gas assets that have significant resource potential and are near high demand areas. Consequently, the Enlarged Group expects that acquisitions will continue to contribute significantly to its future growth. Such acquisitions may be achieved through licence awards following bidding rounds, transfers of participating or other economic interests by an existing licence holder, or direct or corporate acquisitions. However, no assurance can be given that the Enlarged Group will be able to identify attractive acquisition opportunities or, even if it does identify attractive opportunities, that it will be able to complete those acquisitions or do so on commercially acceptable terms.

Successful acquisitions require an assessment of a number of factors, including accurate estimates of recoverable reserves and resources, exploration potential, future oil and gas prices, operating costs, applicable taxes and royalties and potential environmental and other liabilities. Such assessments are inexact and the Enlarged Group cannot necessarily make these assessments with a high degree of accuracy. The Enlarged Group does not inspect every well prior to an acquisition. Even when the Enlarged Group inspects a well, it may not always discover structural, subsurface, environmental or other problems that may exist or arise. Further, it is unlikely that the Enlarged Group will be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, when it makes an acquisition. Acquisitions proving to be worth less than the Enlarged Group anticipated or issues with acquired assets could result in a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

Furthermore, following any such acquisitions of businesses and assets, the Enlarged Group could encounter difficulties in integrating that business's or asset's operations, systems, management and other personnel and technology with its own. Such difficulties could disrupt the Enlarged Group's ongoing business, distract its management and employees and/or increase its expenses.

4.9 ***The Enlarged Group is dependent on key members of management and its technical, financial, operational and marketing teams and its long-term success depends on attracting and retaining skilled personnel.***

The Enlarged Group's competitive position, the implementation of its strategy and its future performance and success depend significantly upon the continued contribution of its key senior management and its technical, financial, operational and marketing personnel. In addition, the personal connections and relationships of the Enlarged Group's key senior management are important to the conduct of its business. Consequently, any departure of a key member of senior management could be detrimental to the Enlarged Group's future success. The Enlarged Group's success is dependent on its management's skill and experience to operate the growing business and discover and develop reserves and resources, identify and conclude acquisitions and develop successful infrastructure solutions for the areas in which it operates. Attracting and retaining additional skilled personnel will be required to ensure expansion of the Enlarged Group's business, and it faces significant competition for skilled personnel in the oil and gas sector willing to work in Nigeria and Niger. Skilled personnel are required in the areas of exploration and development, operations, engineering, business development, oil and gas marketing, finance and accounting for the Enlarged Group's projects.

A failure to retain the services of existing members of the Enlarged Group's senior management, or an inability to attract and retain new and additional senior management personnel could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects. In particular, given the importance of the directorship and leadership of the Company's existing chief executive officer and his knowledge and relationships in the oil and gas industry, the future success of the Enlarged Group is, to an extent, dependent upon the continued service of its chief executive officer. There is a risk that the unexpected departure or loss of this individual could have a material adverse effect on the business, financial condition and results of operations of the Enlarged Group, and there can be no assurance that the Enlarged Group will be able to attract or retain a suitable replacement.

4.10 ***The Enlarged Group's operations are subject to risks, operational hazards and unforeseen interruptions.***

The Enlarged Group's exploration, drilling, production, processing and transportation operations are subject to all the risks and hazards common to the oil and gas industry including, but not limited to, encountering unusual or unexpected rock formations or geological pressures, geological uncertainties, seismic shifts, blowouts, oil spills, explosions, fires, operation of equipment and equipment damage or failure, natural disasters, leakage of hydrocarbons, uncontrollable flows of oil, gas or well fluids, adverse weather conditions, pollution and other environmental risks.

Substantial losses, environmental damage, injury to persons and loss of life, inability to transport gas, failure to produce oil and/or gas in commercial quantities, significant damage to the Company's equipment and/or equipment owned by third parties, inability to produce fully discovered reserves and resources, loss of the licences that enable the Enlarged Group to explore and/or produce oil and gas, curtailment or suspension of operations, incurrence of fines or penalties by the Enlarged Group, or the enforcement of criminal sanctions against the Enlarged Group and/or its officers could result from any such risks or hazards occurring, which could materially adversely affect the Enlarged Group's business, projects, results of operations financial condition and prospects.

4.11 ***The Enlarged Group's operations and those of its partners are subject to health, safety and environmental laws and regulations that may expose it to significant costs and liabilities.***

The Enlarged Group's operations, as well as those of its partners, are often potentially hazardous, and are subject to laws, regulations and provisions in licences relating to the protection of human health and safety and the environment, including those inherent to the oil and gas exploration and production industries. These laws and regulations set various standards for health and environmental quality, provide for penalties and other liabilities for the violation of such standards, and establish, in certain circumstances, obligations to compensate for environmental damage and to restore environmental conditions. Any failure to comply with such requirements may give rise to significant liabilities.

Although the Enlarged Group endeavours to comply with all environmental, health and safety laws and regulations at all times, the Enlarged Group may, in the future, become involved in claims, lawsuits and administrative proceedings relating to environmental, health or safety matters. Breaches of such laws could also be deemed to be a breach of the conditions upon which the Enlarged Group's licences were granted.

An adverse outcome in any such proceedings or other breach of environmental, health or safety laws could have a significant negative impact on the Enlarged Group's reputation as well as its business, prospects, financial condition and results of operations and may include the imposition of civil, administrative or criminal liability on the Enlarged Group or its officers.

Furthermore, the Enlarged Group incurs, and expects to continue to incur, substantial costs in order to comply with the laws, regulations and contractual obligations that it is subject to.

New laws and regulations, the imposition of more onerous requirements in licences, increasingly strict enforcement of, or new interpretations of, existing laws, regulations and licences, or the discovery of previously unknown contamination may require significant material expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups;
- curtail or cease certain operations; or
- pay fees or fines or make other payments for pollution, discharges or other breaches of health, safety and environmental requirements.

Compliance with new requirements may be costly and time consuming and may result in delays in the commencement or continuation of the Enlarged Group's operations.

Moreover, any failure by the Enlarged Group to comply with such requirements may result in the imposition of sanctions, including civil and administrative penalties, upon the Enlarged Group and criminal and administrative penalties applicable to officers of the Enlarged Group. There can be no assurance that the Enlarged Group will be able to comply with existing or new requirements and, as a result, the Enlarged Group may be required to cease certain of its business activities and/or to remedy past infringements. Any such decisions, requirements or sanctions may restrict the Enlarged Group's ability to conduct its operations or to do so profitably.

In addition, the Enlarged Group's operations are also associated with the emission of "greenhouse gases". Ongoing international negotiations aiming to limit greenhouse gas emissions may result in the introduction of new regulations, which may have an adverse impact on the Enlarged Group's operations.

In the future, the costs of the measures taken to comply with applicable health, safety and environmental laws, regulations and licence provisions as well as any liabilities related to their non-compliance could increase and could be significant and could have a material adverse effect on the Enlarged Group, its business, financial condition, results of operations and prospects.

4.12 ***The Enlarged Group does not insure against certain risks and its insurance coverage may not be adequate for covering all losses arising from potential operational hazards and unforeseen interruptions.***

Whilst the Enlarged Group intends to maintain customary insurance cover in respect of its business and operations, it will not be insured against all possible risks. Consequently, there can be no assurance that the Enlarged Group's insurance will be adequate to cover any losses arising as a result of the occurrence of an adverse event affecting its business or operations.

The Enlarged Group may also not be able to obtain or maintain insurance of the type it desires at reasonable rates or may elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the risks presented. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage.

The occurrence of an event or a third party claim that is not covered, or not fully covered, by insurance could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

4.13 ***The Enlarged Group will be subject to future decommissioning liabilities.***

The Enlarged Group, through its licence interests, has assumed certain obligations in respect of the decommissioning of its fields and related infrastructure and is expected to assume additional decommissioning liabilities in respect of its future operations. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells, transportation and production facilities and require the Enlarged Group to make provision for and/or underwrite the liabilities relating to such decommissioning. Any significant increase in the actual or estimated decommissioning costs that the Enlarged Group incurs may adversely affect its results of operations and financial condition. There can be no assurance that the Enlarged Group will not in the future incur decommissioning charges since local or national governments may require decommissioning to be carried out in circumstances where there is no current express obligation to do so, particularly in the case of future licence renewals.

4.14 ***The Enlarged Group's operations are subject to licensing, contractual and regulatory requirements, each of which may be subject to amendment, renewal or reform, which could make compliance more challenging.***

The Enlarged Group's current operations are, and future operations will be, subject to licensing requirements or agreements, regulations and approvals of governmental authorities of Nigeria and Niger for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil and gas. The relevant legislation provides that fines may be imposed and a licence may be suspended or terminated if a licence holder, or party to a related agreement fails to comply with its obligations under such licence or agreement, or fails to make timely payments of levies and taxes for the licensed activity, provide the required geographical information or meet other reporting requirements.

It may, from time to time, be difficult to ascertain whether the Enlarged Group has complied with its obligations under production sharing contracts, farm-out agreements relating to marginal fields and licences as the extent of such obligations may be unclear or ambiguous and regulatory authorities in jurisdictions in which the Enlarged Group does business may not be forthcoming with confirmatory statements that work obligations have been fulfilled, which can lead to further operational uncertainty.

In addition, the Enlarged Group, its indigenous partners or commercial partners, as applicable, have obligations to develop the fields in accordance with the specific requirements under certain licenses and related agreements, field development plans, laws and regulations. If the Enlarged Group was, or they were, to fail to satisfy the such obligations with respect to a specific field, the licence or related agreements for that field may be suspended, revoked or terminated.

4.15 ***Actual or perceived failure by the Enlarged Group to address community issues may adversely affect the Enlarged Group.***

In addition to the strict legal requirements referred to in paragraph 4.11 of this Part 3, oil and gas companies face increasing demands, from the global community generally and from its lenders and non-governmental organisations ("**NGOs**") in particular, to conduct their operations in a manner consistent with wider environmental and social goals. Investors, customers and governments are more actively following the oil and gas industry's performance on environmental responsibility and human rights, including performance in respect of the development of alternative and renewable fuel resources. In particular, strong relationships with local communities and interested NGOs are important when seeking to acquire land or rights of way in connection with the construction of new pipelines, as well as for the ongoing operation and maintenance of the pipeline. If the Enlarged Group becomes subject to adverse publicity or perception as a result of any actual or perceived failure to address social and environmental issues or corporate responsibility matters, then in addition to any potential legal liabilities referred to above, its reputation may be adversely affected which could impact the ability of the Enlarged Group to acquire land for the purposes of laying new pipelines or building new facilities and to build such new pipelines or facilities where to do so requires the support of local communities. The occurrence of any of these events could have a material adverse effect on the Enlarged Group's reputation, as well as its business, results of operations, financial condition and prospects.

4.16 ***Exposure to currency exchange rate fluctuations and inflation will result in fluctuations in the Enlarged Group's cash flows and operating results.***

The Enlarged Group operates internationally and has exposure to currency risk on purchase, sales and cash equivalents that are denominated in currencies other than US dollars, which is the currency of most of the Enlarged Group's receivables and the currency of most of the cash balances that the Enlarged Group maintains. The currencies giving rise to this are principally the British pound sterling, Naira and FCFA.

Whilst the Enlarged Group's GSAs are denominated in US dollars, they provide that the counterparty can choose to settle their payment obligations thereunder in either US Dollars or Naira. As a result, the Enlarged Group may be required, to the extent that it receives payment in Naira and cannot use such Naira amounts to off-set any Naira expenses that it incurs, to convert such Naira amounts into relevant foreign currencies (most notably, US dollars), the currency of most of its working capital requirements, which may expose it to the costs of such currency conversion and to risks of adverse exchange rate fluctuations. The Calabar Downstream GSA contains a foreign exchange true-up clause to protect against this scenario, although there can be no assurances that such provisions will be effective in the event the Calabar NIPP defaults on, or disavows, such obligations.

Furthermore, most of the Enlarged Group's working capital requirements are denominated in US dollars and some of its payment obligations occur in jurisdictions where the US dollar is not an accepted currency, such as the costs it incurs for central administration (including salaries, rent, travel and utilities) and professional costs and expenses in the UK, Nigeria and Niger. In such circumstances, it converts funds to the relevant foreign currencies (most notably, pounds sterling, Naira and FCFA) as its payment obligations become due. The Enlarged Group is also subject to inflation in the countries in which it operates and procures supplies and to fluctuations in the rates of currency exchange between the US dollar and those countries' currencies.

4.17 ***The Enlarged Group operates in a competitive industry.***

The oil and gas industry is competitive in all its phases. Competition can be particularly intense for the acquisition of oil and gas assets and exploration and production licences. The Enlarged Group's competitive position depends on its geological, geophysical and engineering expertise, its management expertise, its financial resources, its ability to develop its assets on time and on budget, its ability to select, acquire and develop economically viable reserves and its ability to foster and maintain relationships with governments of the countries or regions in which it operates. The key competitive challenges facing the Enlarged Group are:

- acquisition of exploration and production licences, including by acquisition of other companies that may already own licences or existing hydrocarbon producing assets and/or by participating in future licensing rounds;
- securing additional GSAs;
- securing contracts with third parties, including potential competitors of the Enlarged Group in other aspects of the oil and gas industry, for the processing of such third parties' gas;

- engagement of third-party service providers, including construction and drilling contractors, whose capacity to provide key services may be limited;
- access to transportation for its oil;
- purchase or hire of capital equipment that may be scarce; and
- attracting and retaining employment of the best qualified and most experienced and skilled management and industry professionals.

The Enlarged Group competes with international and other oil and gas companies. Some of these companies possess or may possess greater technical, physical and financial resources than the Enlarged Group and many not only explore for and produce oil and gas, but also own and operate refining and processing operations and market petroleum and other products on an international basis. Additionally, companies not previously investing in oil and gas or operating in the sector may choose to acquire reserves to establish a firm supply or simply as an investment, increasing competitive pressures.

Competition for exploration permits as well as other investment or acquisition opportunities may continue to increase in the future and there can be no assurance that the Company will succeed in obtaining any additional oil and gas assets or prospects, or, if it is able to do so, that it will be able to acquire such assets or prospects on economically viable terms.

The effects of this competitive landscape may include higher than anticipated prices for the acquisition of licences or assets, increased costs in carrying out the Enlarged Group's activities, reduced available growth opportunities, increased competition for key management or operational personnel and/or restrictions on the availability of equipment or services, as well as potentially unfair business practices.

In addition, the Enlarged Group's ability to remain competitive will require, among other things, management's continued focus on reducing unit costs, improving efficiency and maintaining long-term growth in the Enlarged Group's reserves and production through continued technological innovation.

Any failure by the Enlarged Group to compete effectively could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

4.18 ***The Enlarged Group's exploration and production activities rely on equipment and services provided by third parties, including procurement of drilling rigs, and the availability, quality and cost of such equipment and services cannot be assured.***

As with other companies in the oil and gas industry, the Enlarged Group's oil and gas exploration, development and production activities, as well as those of its partners and third party operators, are directly or indirectly heavily dependent on equipment and services provided by third parties. These include drilling and other field equipment, supplies, infrastructure, seismic acquisition, storage, experts and technical consultants and other equipment and services. In Nigeria and Niger, such equipment and services may not be readily available at the times and places required by the Enlarged Group, its partners or third party operators or at costs that are commercially reasonable, which might impact the execution of the Enlarged Group's exploration, development and production programmes or those of its partners or third party operators of assets in which the Enlarged Group has interests.

The Enlarged Group relies heavily on external contractors to carry out maintenance of the Enlarged Group's assets and infrastructure. As a result, the Enlarged Group is dependent on such external contractors satisfactorily fulfilling their obligations in a timely manner. Any failure by an external contractor may lead to delays or curtailment of the exploration, production, transportation and delivery of the Enlarged Group's oil and gas.

In addition, the costs of third party equipment and services may rise in the future. Higher prices for oil and/or gas may result in a substantial increase in regional exploration and development activities, which could lead to a lack of available equipment and services in Nigeria and Niger and result in further increases in competition for and the prices thereof. In certain cases, further price escalation could pose risks to the profitability and viability of some of the Enlarged Group's projects or those of its partners or third party operators of assets in which the Enlarged Group has interests. Conversely, to the extent the price of oil and/or gas decreases, this may make it uncommercial for the Enlarged Group to continue to develop and exploit its assets.

Some of the services and equipment required by the Enlarged Group, its partners or third party operators are currently only available on commercially reasonable terms from one or a limited number of providers, in particular given the location of the Enlarged Group's operations in Nigeria and Niger. The Enlarged Group's operations and developments may be interrupted or otherwise adversely affected by failure to supply, or delays in the supply of, equipment or services that meet the Enlarged Group's quality requirements or those of its partners or third party operators of assets in which the Enlarged Group has interests. If the Enlarged Group or any of its partners or a third partner operator of assets in which the Enlarged Group has interests is forced to change a provider of such equipment or services, no assurance can be given that adequate replacement equipment or services will be found on a timely basis or at all, or that it would not result in additional costs and interruptions to exploration, development or production and supply continuity to its customers. In the event of a shortage in equipment and/or services, larger competitors may be better able to secure access to such equipment, services, supplies or personnel.

Any failure in performance by third party service providers, external contractors or consultants, increase in costs, scarcity of equipment, services and/or personnel or inability to find adequate replacement services on a timely basis, if at all, could result in delays or curtailment of the exploration, production, transportation and delivery of the Enlarged Group's oil and gas, decrease revenues and/or increase costs for the Enlarged Group, each of which in turn could have a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

4.19 ***The Enlarged Group may be adversely affected by litigation or adverse publicity.***

Save as provided in paragraph 14 of Part 13 of this document, the Enlarged Group currently has no material outstanding litigation or disputes. There can be no guarantee that the past, current or future actions of the Company or Seven will not result in litigation, and there have been a number of cases where the rights and privileges of oil and gas companies have been the subject of litigation. Defence and settlement costs can be substantial, even with respect to claims that have no merit. Due to the inherent uncertainty of the litigation process, there can be no assurance that the resolution of any particular legal proceeding or any adverse publicity surrounding such claim will not have a material adverse effect on the Enlarged Group's business, reputation, prospects, financial condition or results of operations.

4.20 ***A cyber-attack could adversely affect the Enlarged Group's business, financial condition and results of operations.***

Information security risks have generally increased in recent years as a result of the proliferation of new technologies and the increased sophistication and activities of cyber-attacks. The Enlarged Group depends on digital technology, including information systems to process financial and operating data, analyse seismic and drilling information and estimate oil and gas reserves.

Because of the critical nature of the Enlarged Group's IT infrastructure and the increased accessibility enabled through connection to the internet, the Enlarged Group may face a heightened risk of cyber-attack. In the event of such an attack, the Enlarged Group could have its business operations disrupted, property damaged, proprietary and customer or other confidential information stolen; experience substantial loss of revenues, response costs and other financial loss; and be subject to increased regulation, litigation and damage to its reputation.

A cyber-attack could adversely affect the Enlarged Group's business, financial condition and results of operations.

5. Risks relating to operating in Nigeria

5.1 ***The Enlarged Group has to manage logistical and operational difficulties as a result of carrying out its operations in Nigeria.***

The Enlarged Group has to manage logistical and operational difficulties as a result of carrying out operations in Nigeria. Persistent problems with power generation, transmission and distribution, a deteriorating and congested road network, congested ports and obsolete rail infrastructure have severely constrained socio-economic development in Nigeria.

Moreover, infrastructure in south eastern Nigeria is limited and unreliable. Rail and road infrastructure is relatively limited and restricts the movement of people and goods within those regions thereby increasing the time it takes to mobilise workforces and deliver supplies or equipment. The lack of reliable infrastructure also limits the Enlarged Group's ability (and that of its partners, contractors, customers and suppliers) to respond quickly to unforeseen situations, which can lead to delays and production stoppages.

5.2 ***South East Nigeria periodically experiences adverse weather conditions and disasters.***

South East Nigeria, in which the Uquo Field and Stubb Creek Field are both based, periodically experiences adverse weather conditions and natural disasters, mainly in the form of floods, which further limits the use of available infrastructure, particularly during the rainy season (March to November), and increases the likelihood of delays during that part of year. In addition, flooding in the Niger Delta has also led to outbreaks of disease which, coupled with the ongoing security concerns in relation to the region (see paragraphs 5.6 and 5.7 of this Part 3), may affect the Enlarged Group's ability to staff its operations with qualified Nigerian and overseas individuals if such individuals were deterred from relocating to the Niger Delta, or to Nigeria more generally, as a result of health or security concerns.

5.3 ***The Nigerian economy is dependent on oil production in Nigeria and global prices of oil.***

The Nigerian economy is highly dependent on oil production in Nigeria and global prices of oil. Reductions in oil revenues could have a material adverse effect of the Nigerian economy, and in turn on the Enlarged Group's business and results of operations. The Nigerian government relies heavily on oil revenue to fund its budget and the decline in prices has resulted in a high rate of unemployment, reduction in foreign exchange and government revenue, as well as significant budgetary constraints, leading to less investment in key projects such as infrastructure.

5.4 ***The regulatory environment in the oil and gas sector in Nigeria is subject to significant ongoing change.***

Nigeria is pursuing a number of new policy initiatives with the aim of restructuring its oil and gas industry including streamlining and revising obsolete laws and adopting new or revised regulations. However, the final form that these reforms will take is currently uncertain and may be subject to political and economic influences. One of such reforms is the proposed PIB which was first submitted to the National Assembly in 2008, and has since been pending until 2016 when the Federal Government resolved to split the PIB into four bills, namely the Petroleum Industry Governance Bill 2016 ("**PIGB**"), the Fiscal Regime Bill, the Upstream and Midstream Administration Bill and the Petroleum Revenue Bill. The Nigerian Senate passed the PIGB on 25 May 2017 and if passed by the House of Representatives, the bill would be presented to the President of the Federal Republic of Nigeria for his assent, following which it will take effect in accordance with the provisions of the Bill.

The risks associated with the proposed reforms in the Nigerian oil and gas industry include that:

- no assurance can be given as to when the PIGB will be passed by the House of Representatives, and when other parts of the PIB will be enacted or whether they will be enacted at all, or that the final form of any of them when enacted will not differ significantly from their current drafts of the bills, all of which prevents a proper assessment of the potential impact of the current drafts of the bills on the Enlarged Group's business and operations and on the wider oil and gas industry in Nigeria;
- the proposed changes in the tax structure for, and allowances available to, oil and gas companies operating in Nigeria may, if less favourable to the Enlarged Group than under the existing regime, have a material adverse effect on the Enlarged Group's results of operations and financial condition, and, if unfavourable to other companies operating in Nigeria, may lead to such other companies curtailing their operations or future investment, the occurrence of which could have a material adverse effect on the Enlarged Group's midstream gas operations;
- no assurance can be given that the initiatives designed to promote gas production and adjustment of gas prices (as contemplated under the National Gas Policy) will fully be implemented; and

- the proposed bills may fail to adequately address the concerns of relevant stakeholders.

In addition to the proposed PIB, other legislative and regulatory changes affecting the Nigerian oil and gas sector have been implemented by the Nigerian Government. In February 2008, the Nigerian Government announced the Gas Master Plan with the aim of providing solutions to the issues of gas pricing, domestic gas supply and development of gas infrastructure within Nigeria. In a bid to give effect to the Gas Master Plan, the Nigerian Government issued the National Domestic Gas Supply and Pricing Policy ("**NDGSPP**") and the National Domestic Gas Supply and Pricing Regulations ("**NGSPR**"). The NDGSPP recognises a "domestic reserves obligation", and the NGSPR imposes a "domestic gas supply obligation". The effect of both of these obligations is to impose a requirement on all licensed petroleum producers to dedicate a specific volume of gas for strategic sectors within the domestic economy and to deliver such gas to a purchaser in accordance with a specified nominations procedure.

Any changes to the NDGSPP or the NGSPR, and the implementation of new policies and initiatives pursuant to the proposed PIB, may have a material adverse effect on the Enlarged Group's business, results of operation, financial condition and prospects.

5.5 ***Local content legislation in Nigeria may impact upon the Enlarged Group's ability to recruit suitably qualified individuals.***

The Nigerian Local Content Act which was enacted in April 2010, provides a framework for increasing Nigerian participation in all sectors of the Nigerian oil and gas industry. The Local Content Act prescribes minimum thresholds for Nigerian participation in oil and gas activities and also impacts the day to day management of companies operating in the oil and gas industry by imposing requirements concerning, among others, the use and involvement of Nigerian labour in their operations. This may adversely impact on the Enlarged Group's ability to hire suitably qualified persons and, consequently, the costs of the Enlarged Group's operations in Nigeria.

5.6 ***Political instability, religious differences, ethnicity, regionalism and internal security in Nigeria pose risks that impact Nigerian oil and gas production.***

With the adoption of a new presidential constitution in May 1999, Nigeria is experiencing its longest period of civilian rule since obtaining independence from the United Kingdom in 1960. The next general election is due to be held in 2019. Political tensions and incidences, including civil unrest, have been seen around the time of, or leading up to, previous elections held in Nigeria, and there can be no assurance that similar incidents will not take place in relation to future elections. In the past, results of elections in Nigeria have been subject to criticism by both opposition candidates and international election observers. Although such unrest subsequently subsided, there can be no assurance that results of the 2019 general election will not be subject to challenge or result in further outbreaks of unrest and discontent. Further, if there are allegations of fraud or other irregularities in connection with the presidential elections and such allegations are not properly handled in an orderly manner, such allegations may undermine the legitimacy of the new administration.

The outcome of elections may have a significant impact on Nigeria's political stability and may adversely affect its economy, and no assurance can be given that the reforms and policies that are proposed or taking place will continue. Any post-election administration may pursue different policies and priorities, alter or reverse certain reforms or take actions (including a highly unlikely expropriation or nationalisation (which in any case is required to be with adequate compensation), breach or abrogation of project agreements) that make domestic and foreign investment in Nigeria less attractive or lead to protests, violence or other unrest. Any significant changes in the political climate in Nigeria, including changes affecting the stability of the Nigerian Government or involving a rejection, reversal or significant modification of policies, favouring the privatisation of state-owned enterprises, reforms in the power, banking or oil and gas sectors, may have negative effects on the economy, government revenues or foreign reserves and, as a result, a material adverse effect on the Enlarged Group's business, results of operations, financial condition and prospects.

5.7 ***Militant and unlawful activity could destabilise oil production in Nigeria and adversely affect the Enlarged Group's operations and Nigeria's economy.***

Militant and unlawful activity, violence and civil disturbances have, in the past, caused intermittent problems in the Niger Delta. Various militant groups had until more recently following political engagement at the highest level been conducting guerrilla attacks on crude oil pipelines and other related infrastructure, kidnapping oil and gas workers for ransom and generally disrupting the activities of oil and gas companies with operations in the Niger Delta, and more broadly throughout Nigeria. Militant and unlawful activity has, in the past, resulted in companies being forced to decrease production or to even consider ceasing their operations in Nigeria as a result of attacks on, or threats to, their operations and staff. However, to date, no oil company has actually ceased its operations in Nigeria as a result of militant activity.

5.8 ***Any gas flaring in violation of the Gas Flaring Act could lead to financial penalties and/or forfeiture of licences or legal interests.***

Most of Nigeria's oil fields produce significant amounts of associated gas, much of which is flared. Gas flaring is the burning of the associated gas that cannot be processed or sold. Although the existing "zero flaring" legislation in Nigeria, the "Gas Flaring Act", generally prohibits gas flaring, it empowers the Minister of Petroleum Resources to permit flaring subject to certain conditions, including the payment of a fee prescribed by the Minister from time to time for each standard cubic meter of gas flared.

5.9 ***Labour unrest could affect the Enlarged Group's ability to explore for, produce and market its oil and gas production.***

Seven has in the past been subject to strikes from both workers at Universal and the workers of hired contractors, and there can be no assurance that the Enlarged Group will not be subject to strikes in the future. Any strike activity or labour unrest (whether as a result of a broader social and/or labour unrest within Nigeria or otherwise) at any of the Enlarged Group's oil and gas operations or at, or affecting, the operations of any third party which the Enlarged Group utilises for its business, could adversely affect the Enlarged Group's ongoing operations and its ability to explore for, produce and market its oil and gas which could adversely affect the Enlarged Group's business, results of operations, financial condition and prospects.

5.10 ***The Enlarged Group may be subject to currency controls which may limit its ability to attract appropriately skilled staff and purchase required services.***

The Nigerian Government has imposed foreign exchange restrictions to control the flow of dollars in and out of the country. The controls prohibit the use of currencies other than the Naira as a means of payment for certain items. The imposition of foreign exchange controls may have an adverse effect on the Enlarged Group's ability to attract and retain appropriately skilled staff and pay for required services in Nigeria.

5.11 ***Importance of maintaining good title to licence interests.***

The Enlarged Group's right to explore and exploit its licence interests and Accugas' ability to operate the Accugas Midstream Business are reliant on the establishment and maintenance of good title to the licence interests both entities purport to hold. Whilst the Enlarged Group and Accugas seek to ensure that they have good title to the participating interests they purport to own, they cannot completely eliminate the risk of future title disputes or challenges. A successful challenge to the Enlarged Group's title to assets may result in the Enlarged Group being required to halt development or production or operations or, ultimately, in the loss of such assets.

5.12 ***The taxation and customs systems in Nigeria may be subject to change and the rules of those systems may be subject to different interpretation.***

Nigeria is an emerging market economy, and its policies and regulations on, and laws relating to, taxation, customs and excise duties may change from time to time as considered necessary for its further development. The Enlarged Group's existing effective tax rate and revenues may be affected by changes in such policies, laws or regulation. In particular, the draft PIB will, if enacted, change the taxation regime applicable to oil and gas companies and may affect the existing effective tax rates and the amount of tax payable by the Enlarged Group and by its partners (which will, in certain circumstances, affect the amount of revenue received by the Enlarged Group).

Further, the Nigerian FIRS's interpretation of, and/or decisions with respect to, certain sections of applicable tax laws or regulations may differ from the Enlarged Group's interpretation of such laws or regulations. Such interpretation or decision by the Nigerian FIRS could result in additional tax becoming due or payable in the future by the Enlarged Group.

Changes in applicable policies on taxation, customs and excise duties, as well as differences in interpretation of and decisions relating to tax laws, may have an adverse effect on the Enlarged Group's business, results of operations, financial position and prospects.

5.13 ***The Enlarged Group may be required to pay higher levels of withholding tax on dividend payments by the Enlarged Group's Nigerian subsidiaries if Nigerian law or practice were to change.***

Withholding tax on the payment of dividends in Nigeria depends on whether the profit distributed was derived from upstream oil or gas activities. Withholding tax will not be chargeable on the dividends from income derived from petroleum operations as provided in section 60 of the PPTA. The Nigerian withholding tax rate on dividends is generally 100 per cent., but Nigeria grants unilaterally a reduced rate of 7.5 per cent. where the recipient is in a country that has a double taxation treaty with Nigeria.

5.14 ***The Nigerian judicial system may create an uncertain environment for investment and business activity.***

Nigerian law is predicated on the common law system, with its roots being derived from the English legal system.

The Nigerian legal system continues to develop and faces a number of challenges including delays in the judicial process, as most cases, even spurious claims, take a considerable period of time to be concluded. As a result, obtaining effective legal redress may be delayed and there is a high degree of uncertainty due to some level of discretion that may be exercised by the courts. There is also a lack of judicial or administrative guidance on interpreting applicable rules and regulations, inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions and relative inexperience of the judiciary and courts in commercial matters. However, recent years have witnessed considerable reform of the judiciary, especially in Lagos State with the setting up of commercial courts and the introduction of new rules to cut down on delays in the judicial process.

The slow judicial process may sometimes affect the enforceability of judgments obtained. In addition, the enforcement of laws may depend on, and be subject to the interpretation of, the relevant local authority, and such interpretation may differ from the advice given to the Enlarged Group by local lawyers.

These and other factors that have an impact on Nigeria's legal system make an investment in the Ordinary Shares subject to greater risks and uncertainties than an investment in a country with a more mature legal system.

6. Risks relating to operating in Niger

6.1 ***The Enlarged Group could experience logistical and operational difficulties as a result of carrying out its operations in Niger.***

Niger is one of the least developed countries in the world and has limited infrastructure. The Enlarged Group could therefore experience logistical and operational difficulties as a result of carrying out its operations in Niger.

6.2 ***Militant activity could destabilise oil operations in Niger and adversely affect the Enlarged Group's exploration activities and Niger's economy in general.***

Niger faces a threat of terrorism. One element of this risk arises as a result of its proximity to various Islamist insurgencies, including Boko Haram. Whilst the Board believes that the Enlarged Group's assets are located some distance from historical terrorist incidents, and have not been negatively impacted by terrorist incidents to date, there is no guarantee that this will be the case in the future.

6.3 ***The Nigerien judicial system may create an uncertain environment for investment and business activity.***

A number of the Enlarged Group's principal agreements including the Savannah PSCs are governed under Niger law. The courts in Niger may offer less certainty as to the judicial outcome or a more protracted judicial process than is the case in more established economies. However, the Savannah PSCs offer the option of a recourse to an international arbitration procedure in accordance with the International Centre for Settlement of Investment Disputes and the Convention on the settlement of investment disputes between States and nationals of other States, the "Washington Convention". Nevertheless, the Enlarged Group could face risks, such as: (i) effective legal redress in the courts being more difficult to obtain, whether in respect of a breach of law or regulation, or in an ownership dispute; (ii) a higher degree of discretion on the part of governmental authorities and, therefore, less certainty; or (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations. Enforcement of laws in Niger may also depend on and be subject to the interpretation placed upon such laws by the relevant local authority, and such authority may adopt an interpretation of an aspect of local law which differs from the advice that has been given to the Enlarged Group by local lawyers or even previously by the relevant local authority itself.

6.4 ***Local content legislation in Niger may impact upon the Enlarged Group's ability to recruit suitably qualified individuals.***

The local content rules contained in the Petroleum Code and in the Savannah PSCs could impact the Enlarged group's operations in Niger. Such rules oblige licence holders to employ, as a priority, qualified Niger nationals for the purposes of their petroleum operations. There is also an obligation on the Enlarged Group to comply with a recruitment programme and a training programme of the Nigerien personnel. This may adversely impact on the Enlarged Group's ability to hire suitably qualified persons and, consequently, the costs of the Enlarged Group's operations in Niger.

6.5 ***The Enlarged Group is subject to taxation including, but not limited to, that as outlined in the Savannah PSCs.***

The Enlarged Group is subject to taxation and fiscal terms including, but not limited to those outlined in the Savannah PSCs (summarised in Part 15 of this document). The application of such taxes together with taxes levied in other applicable jurisdictions, may change over time due to changes in laws, regulations or interpretations by the relevant tax authorities. Whilst no material changes are anticipated in such taxes any such changes may have a material adverse effect on the Enlarged Group's financial condition and results of operations.

6.6 ***Restrictions on exchange controls could impact on the Enlarged Group's operations in Niger***

There are currently no restrictions on transfer of funds into Niger, but any resident company intending to transfer foreign currency out of the country must provide supporting documentation. If restrictions on exchange controls are changed then it could be a risk to the Enlarged Group's operations and prospects, otherwise the Enlarged Group's financial conditions may be materially adversely affected, as would its ability to pay dividends on Ordinary Shares should any be declared and if the Nigerien business starts to generate cash flows.

6.7 ***Exploration and development activities in developing countries such as Niger may require protracted negotiations with host governments.***

Exploration and development activities in developing countries such as Niger may require protracted negotiations with host governments, national oil companies and third parties. The two main protections granted to the Company under the Savannah PSCs are: (i) the stability of the legislation and the terms agreed under the PSC and the commitment that the Government of Niger shall never: (a) directly or consequently increase the obligations and responsibilities imposed on Savannah Niger; nor (b) infringe the latter's economic rights and advantages resulting from Law of 2007 (see definition on page 470) and the Savannah PSCs; and (ii) the arbitration procedure according to which any dispute relating to the Savannah PSCs which cannot be settle amicably shall be resolved by means of arbitration conducted in accordance with the Arbitration Rules of the International Centre for Settlement of Investment Disputes and the Convention on the settlement of investment disputes between States and nationals of other States, the "Washington Convention". The Savannah PSCs provides that the dispute shall be resolved in accordance with its provisions, the Law of 2007 and the provisions of international law applicable in the area.

7. Risks relating to operating in emerging markets

7.1 ***Emerging markets such as Nigeria and Niger are subject to greater risks than more developed markets.***

Investing in securities of issuers whose operations and assets are located in emerging markets, such as Nigeria and Niger, generally involves a higher degree of risk than investments in securities of corporate or sovereign issuers from more developed countries and carries risks that are not typically associated with investing in more mature markets.

These risks include, but are not limited to:

- greater political risk, and changes in, and instability of, the political and economic environment;
- civil strike, acts or war, terrorism and insurrection;
- government interventions;
- potential adverse or unforeseen changes in laws and regulatory practices, including import and export licence requirements and restrictions, tariffs, legal structures and tax laws;
- trade barriers;
- difficulties in staffing and managing operations;
- lack of well developed legal systems, which could make it difficult for the Enlarged Group to enforce contractual rights and intellectual property;
- security and safety of employees;
- risk of uncollectible accounts and long collection cycles;
- adverse currency fluctuations, restrictive foreign exchange regulations and illiquidity in the foreign exchange markets;
- consequences of corrupt practices on the economy;
- infrastructure challenges;
- logistical and communication challenges; and
- changes in labour conditions.

These risks may cause higher volatility and more limited liquidity in respect of the Ordinary Shares. Investors should exercise particular care in evaluating the risks involved and must decide for themselves whether, in light of those risks, their investment is appropriate.

7.2 ***Financial turmoil in any emerging market could disrupt the Enlarged Group's business.***

Financial problems or an increase in the perceived risks associated with investing in emerging economies could dampen foreign investment in Nigeria and Niger and adversely affect the Nigerian and Nigerien economies. In addition, during such times, companies that operate in emerging markets can face severe liquidity constraints as foreign funding sources are withdrawn.

Companies in emerging market countries may be particularly susceptible to disruptions in the capital markets and the reduced availability of credit or increased cost of debt, which could result in them experiencing financial difficulty. In addition, the availability of credit to entities operating within emerging markets is significantly influenced by levels of investor confidence in such markets as a whole and so any factors that impact market confidence (for example, a decrease in credit ratings, state or central bank intervention or foreign funding sources being withdrawn) could negatively affect the price or availability of funding for the Enlarged Group.

7.3 ***By doing business in emerging markets, the Enlarged Group could potentially face, directly or indirectly, corrupt demands from third parties.***

The Enlarged Group is subject to Compliance Laws that prohibit companies and their intermediaries from making improper payments or offers of payments to foreign governments and their officials and political parties, or others for the purpose of obtaining or retaining business and/or other benefits.

By doing business in Nigeria and Niger, the Enlarged Group could face, directly or indirectly, corrupt demands by officials, militant groups or private entities. Consequently, the Enlarged Group could face the risk of unauthorised payments or offers of payments by one of its employees, agents, intermediaries or consultants, given that such persons may not always be subject to its control. Due diligence conducted by the Company identified that the Seven Group had policies and procedures designed to ensure compliance with Compliance Laws. In certain limited services these policies and procedures were not as effectively implemented as Savannah could expect to be the core in the Enlarged Group.

Whilst the Enlarged Group has policies and procedures designed to ensure compliance with Compliance Laws, however no assurance can be given as to the effectiveness of these policies and procedures and whether they will be effective or be rigorously applied by the Enlarged Group's employees, intermediaries and consultants with respect to the Enlarged Group's business. Accordingly, there is a risk that defences against UK Bribery Act offences may not be available to the Enlarged Group, should it be found that any offence has been committed. If the Enlarged Group was not in compliance with Compliance Laws, it may be subject to criminal and civil penalties and other remedial measures.

Furthermore, any remediation measures taken in response to potential or alleged violations of Compliance Laws, including any necessary changes or enhancements to the Enlarged Group's procedures, policies and controls and potential personnel changes and/or disciplinary actions, may result in increased compliance costs and could materially adversely impact its business, results of operations, financial condition and prospects.

Any such findings, or any alleged or actual involvement in corrupt practices or other illegal activities by the Enlarged Group or its partners or anyone with whom the Enlarged Group conducts business could damage the Enlarged Group's reputation and its ability to do business, including by affecting its rights and title to assets or by the loss of key personnel, and could adversely affect its results of operations, financial condition and prospects.

While the due diligence conducted by the Company identified that the Seven Group had policies and procedures designed to ensure compliance with Compliance Laws, no assurance is given to the effectiveness of these policies and procedures at all times. The due diligence also identified some circumstances where the policies and procedures may not always have been effectively implemented.

7.4 ***Nigeria and Niger suffer from poverty and unemployment and economic risk and instability.***

Poverty remains high in Nigeria, with approximately 50 per cent. of the population living below the poverty line in the northern states in 2016, according to the World Bank. In addition, poverty remains high in Niger. Approximately 49 per cent. of the population live below the poverty line according to the World Bank.

If high levels of poverty and unemployment are not addressed, they could continue to be a source of political and social instability in Nigeria and Niger, including violence. Furthermore, failure to reduce poverty and unemployment may individually, or in aggregate, have negative effects on the Nigerian and Nigerien economy and, as a result, a material adverse impact on the Enlarged Group's business, results of operations and financial condition.

8. Risks relating to the Ordinary Shares

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

There can be no assurance that an active or liquid trading market for the Ordinary Shares will develop or, if developed, that it will be maintained. AIM is a market designed primarily for emerging or smaller growing companies which carry a higher-than-normal financial risk and tend to experience lower levels of liquidity than larger companies. Accordingly, AIM may not provide the liquidity normally associated with the Official List or some other stock exchanges. The Ordinary Shares may therefore be difficult to sell compared to the shares of companies listed on the Official List, and the share price may be subject to greater fluctuations than might otherwise be the case.

The share prices of publicly quoted companies can be highly volatile and shareholdings illiquid. The price at which the Ordinary Shares are quoted and the price which investors may realise for their Ordinary Shares may be influenced by a large number of factors, some of which are general or market-specific, others which are sector-specific and others which are specific to the Enlarged Group and its operations. These factors include, without limitation, the performance of the Enlarged Group and the overall stock market, large purchases or sales of Ordinary Shares by other investors, changes in legislation or regulations, and changes in general economic, political or regulatory conditions and other factors which are outside of the control of the Enlarged Group.

8.2 ***The price of the Ordinary Shares is subject to volatility.***

The value of the Ordinary Shares may decrease or increase abruptly, and such volatility may bear little or no relation to the Enlarged Group's performance. The price of the Ordinary Shares may fall in response to market appraisal of the Enlarged Group's strategy or if the Enlarged Group's results of operations and/or prospects are below the expectations of market analysts or shareholders.

In addition, stock markets worldwide have experienced significant price and volume fluctuations since 2008 that have affected the market price of securities, and may in the future, experience similar fluctuations that may be unrelated to the Enlarged Group's operating performance and prospects but that may nevertheless affect the price of the Ordinary Shares.

Other factors which may affect the price of the Ordinary Shares include, but are not limited to:

- the results of exploration, development and appraisal programmes and production operations;
- differences between the Enlarged Group's expected and actual operating performance;
- cyclical fluctuations in the performance of the Enlarged Group's business;
- speculation, whether or not well founded, regarding the intentions of the Enlarged Group's major Shareholders or significant sales of shares by any such Shareholders or short selling of the Ordinary Shares;
- speculation, whether or not well founded, about significant issues of Ordinary Shares by the Enlarged Group;
- speculation, whether or not well founded, regarding possible changes in the Enlarged Group's management team;
- publication of research reports by analysts;
- strategic actions by the Enlarged Group or its competitors, such as mergers, acquisitions, divestitures, partnerships and restructurings;
- speculation, whether or not well founded, about the Enlarged Group's business, about mergers or acquisitions involving the Enlarged Group and/or major divestments by the Enlarged Group in the press, media or investment community; and
- general market conditions and regulatory changes.

8.3 ***The Company has not registered the Placing Shares, the Warrants or the Shares underlying the Warrants, which will limit shareholders' ability to resell them in the US.***

The Placing Shares, the Warrants or the Shares underlying the Warrants, have not been registered under the US Securities Act or any US state securities laws and the Company does not intend to file a registration statement for the resale of the Placing Shares, the Warrants or the Shares underlying the Warrants. Unless the Placing Shares, the Warrants or the Shares underlying the Warrants, are registered, they may not be transferred or resold except in a transaction exempt from or not subject to the registration requirements of the Securities Act and applicable state securities laws.

8.4 ***Substantial future sales of Ordinary Shares, or the perception of such sales, could impact the market price of Ordinary Shares.***

The new Ordinary Shares to be issued to the holders of the SSNs and the Second Bilateral Facility pursuant to the Capital Restructuring (please refer to Part 2 of this document for further details) will be subject to lock-in provisions that will restrict transfers of such shares for a period of six months from the completion date of the Capital Restructuring without the Company's prior consent, and then for a further month such that any sales are done in a manner which protects an orderly market in the Ordinary Shares.

The Company is unable to predict whether substantial amounts of the Ordinary Shares will be sold in the open market by the holders of the SSNs and the Second Bilateral Facility following the termination of these lock-up restrictions or by other shareholders. Any sales of substantial amounts of the Ordinary Shares in the public market, or the perception that such sales might occur, could result in a material adverse effect on the prevailing market price of the Ordinary Shares and could impair the Company's ability to raise capital through the sale of additional equity securities.

8.5 ***Issuances of equity may result in shareholder dilution***

The Company may seek to raise financing to fund future acquisitions, capital expenditures and other growth opportunities. The Company may, for these and other purposes (such as in connection with share incentive and share option plans or the exercise of any of the Warrants) issue additional equity or convertible equity securities. As a result, the Company's existing shareholders would likely suffer dilution in their percentage ownership, and such an issue, or the perception that such an issue may occur, could have a material adverse effect on the prevailing market price of the Ordinary Shares.

8.6 ***US and other non-UK holders of Ordinary Shares may be unable to exercise their pre emptive rights.***

In the case of certain increases in the Company's issued share capital, existing holders of Ordinary Shares are generally entitled to pre emption rights pursuant to the Companies Act to subscribe for such Ordinary Shares, unless shareholders waive such rights by a special resolution at a shareholders' meeting, or in certain other circumstances as stated in the Articles. To the extent that pre-emptive rights are granted, US and other non UK holders of Ordinary Shares may be not be able to exercise those rights unless the Company decides to comply with applicable local laws and regulations and, in the case of US holders, unless a registration statement under the Securities Act is effective with respect to those rights or an exemption from the registration requirement thereunder is available. The Company intends to evaluate at the time of any rights issue or other offering the costs and potential liabilities associated with any such compliance or registration statement. At such time, the Company would also intend to evaluate the benefits to it of enabling the exercise by US and other non-UK Shareholders of the pre-emptive rights for their Ordinary Shares and any other factors the Company considers appropriate at the time. On the basis of this evaluation, the Company will then make a decision as to how to proceed and whether or not to file such a registration statement or take any other steps necessary to extend the rights offering to any other jurisdictions (including complying with local law requirements in other jurisdictions). No assurance is given that any steps will be taken in any jurisdiction or that any registration statement will be filed to enable US or other non UK holders of Ordinary Shares to exercise their pre emption rights or to permit them to receive any proceeds or amounts relating to their pre-emption rights. If US or other non UK holders of Ordinary Shares are not able to receive, trade or exercise pre-emption rights granted in respect of their Ordinary Shares in any rights issue or other offering by the Company, then they may not receive the economic benefit of those rights. In addition, such holders' proportional ownership interests in the Company will be diluted.

8.7 ***The Company's ability to pay dividends in the future is not guaranteed.***

Further dividends will depend on, among other things, the results of the Enlarged Group's operations, its financial condition, capital requirements, distributable reserves, general economic conditions, future prospects and other factors that the Directors deemed to be relevant at the time.

8.8 ***Exchange rate fluctuations may adversely affect the foreign currency value of the Ordinary Shares and any dividends.***

The Ordinary Shares will be quoted in pounds sterling on the London Stock Exchange. Dividends in respect of the Ordinary Shares, if any, will be declared in US dollars. The Enlarged Group's financial statements are prepared in US dollars with underlying US dollar and Naira exposure. Fluctuations in the exchange rate between the US dollar, Naira and pounds sterling will affect, amongst other matters, the pounds sterling value of the Ordinary Shares and of any dividends.

It should be noted that the risk factors listed above are not intended to be exhaustive and do not necessarily comprise all of the risks to which the Enlarged Group is or may be exposed or all those associated with an investment in the Company. In particular, the Company's performance is likely to be affected by changes in market and/or economic conditions, political, judicial, and administrative factors and in legal, accounting, regulatory and tax requirements in the areas in which it operates and holds its major assets. There may be additional risks and uncertainties that the Directors do not currently consider to be material or of which they are currently unaware which may also have an adverse effect upon the Enlarged Group.

If any of the risks referred to in this Part 3 crystallise, the Enlarged Group's business, financial condition, results or future operations could be materially adversely affected. In such case, the price of its Ordinary Shares could decline and investors may lose all or part of their investment.

Although the Directors will seek to minimise the impact of the risk factors listed above, investment in the Enlarged Group should only be made by investors able to sustain a total loss of their investment.

PART 4

OIL AND GAS INDUSTRY OVERVIEW

From the period of early 2000 to the middle of the last decade, global oil prices increased dramatically due to a rise in demand from the emerging economies, led by China; while on the supply side the industry faced difficulties in keeping pace with surging demand following decades of low prices ($10 – 20/bbl). The period of price growth continued exponentially (reaching circa $140/bbl) until 2008, leading up to the global financial crisis. By the end of 2009, the price of crude oil had rebounded and continued to stabilise around $90 – 100/bbl.

In late 2014, crude oil prices experienced a severe drop as a result of OPEC's decision to maintain production output levels on the back of strengthening non-OPEC supply out of the United States (led by the shale revolution), anemic global demand growth and an economic slow-down in China. This resulted in a supply and demand imbalance, causing global oil prices to weaken throughout 2015 and 2016, and increase market uncertainty around OPEC's willingness to provide price support.

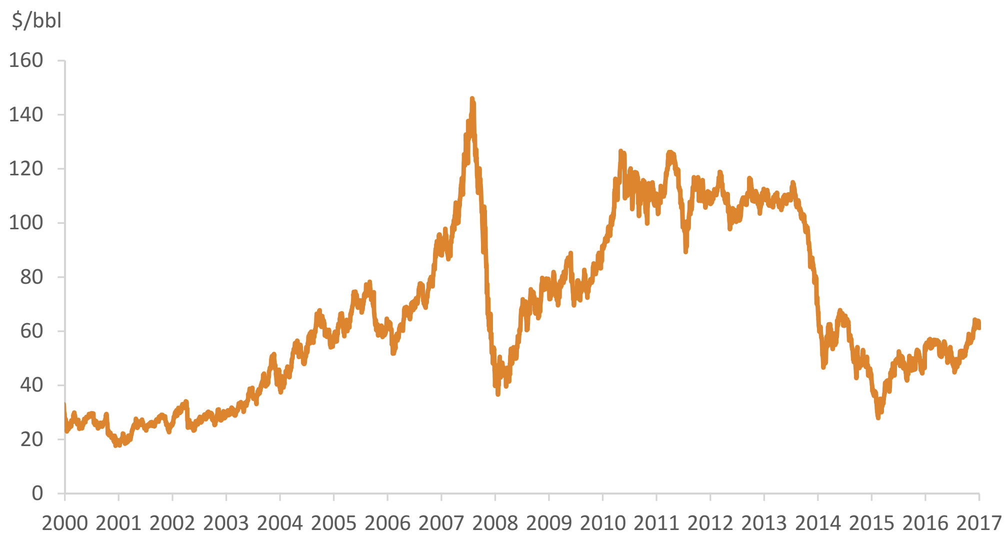
During 2016, Brent averaged $45/bbl, the lowest nominal annual average since 2004, and almost half of its 2014 levels[8]. However the continued resilience in crude oil supply and record global oil inventories led OPEC to change tactics at the OPEC meeting in Vienna on 30 November 2016, and the group agreed to its first production cuts in eight years, alongside a group of 11 non-OPEC nations, including Russia. As a result of the agreement, Brent moved to $53.6/bbl in December – the highest monthly average since July 2015.

During the first months of 2017 the oil price traded in a narrow $53-56/bbl range as the market monitored OPEC and non-OPEC member states for compliance with the Vienna agreement. By June 2017 on the back of continued rise in U.S. production, compounded by low confidence on compliance, oil price dropped to below $50/bbl. Both Nigeria and Libya had also increased production after earlier outages. By the later part of 2017 oil prices rose on the back of Hurricanes Harvey and Irma's impact on southern U.S. refineries and infrastructure.

On 30 November 2017, following the latest OPEC meeting, OPEC and Russia has agreed to extend production cuts into second half of 2018, in order to continue price support. American oil production grew to 9.66 million barrels per day in November, compared to 8.70 million barrels per day in December 2016[9]. Current Brent oil price is trading at $62.2/bbl[10], at a two year high.

Figure 12, Historical Brent Crude Price

Historical Brent Crude Price (US$/bbl)



Source: FactSet, as at 07.12.17

[8] BP Statistical Review of World Energy, June 2016
[9] EIA, Weekly US Field Production of Crude Oil
[10] FactSet Brent Crude spot price, 7 December 2017

PART 5

NIGERIA COUNTRY OVERVIEW

Introduction

The Federal Republic of Nigeria ("**Nigeria**") is a federation in West Africa comprising thirty six states and the Federal Capital Territory, Abuja. Abuja is primarily a governmental and administrative city, with Lagos recognised as the commercial capital of the country. Historically Nigeria was made up of kingdoms and tribal states; the modern state was formed during British colonial rule beginning in the 19th century, and the merging of the Southern Nigeria Protectorate and Northern Nigeria Protectorate in 1914. Nigeria became a formally independent federation in 1960.

Geographically, Nigeria borders Cameroon and Chad to the East, the Republic of Benin to the West, and the Republic of Niger to the North. It also has a coast in the South that lies on the Gulf of Guinea in the Atlantic Ocean. Nigeria has an abundant supply of natural resources, with a primary focus on oil and gas production out of the Niger Delta. The country benefits from a developed financial and legal system, and the second largest stock exchange in Africa. Currently the oil and gas industry contributes to circa 40 per cent. of Nigeria's government revenues[11]. Although the country has been impacted by the now recovering lower oil prices and reduced production in recent times, GDP growth is expected to pick up at about 1.7 per cent. in 2018. Nigerian GDP at current prices is US$4,960 per capita[12].

The country has a large, mostly young and urbanised population of approximately 190 million people[13], making it Africa's most populous country, and the seventh most populous country in the world. Nigeria's population consists of over 250 ethnic groups, with the Hausa/Fulani, Yoruba and Igbo being the largest ethnic groups. Nigeria is nearly equally divided between Christianity and Islam, with the Christian population living mostly in the southern part of the country and the Muslim population living mostly in the north. English is the official language of Nigeria. In addition to English, Hausa, Yoruba and Igbo languages are also predominantly spoken in the northern, western and eastern parts of the country, respectively.

Government and Political environment overview

- *The Government*

Nigeria gained independence from the United Kingdom on 1 October 1960 and became a republic in 1963. The current Constitution of Nigeria was enacted on 29 May 1999, under Nigeria's Fourth Republic.

The Constitution provides for three tiers of government, namely, the Federal Government at the centre, the governments of the respective 36 States and municipal authorities in the 774 local government or area councils that make up the 36 States and the Federal Capital Territory.

At all the levels of government, there is a separation of powers among the executive, the legislative and judicial arms of government. The executive powers of the Federal Government are vested in the President who is elected for a four-year term, subject to a limit of two terms. The legislative powers are given to the National Assembly which comprises two chambers, namely: (i) the Senate; and (ii) the House of Representatives, while the judicial powers are vested in various courts in the chain with the Supreme Court of Nigeria being the highest court in the country.

- *Elections and Change of Government*

The country has experienced numerous political changes since its independence including a series of military coups. In 1999, after 39 years of independence (28 of which were under military rule characterised by political instability), a peaceful transition to civilian government was completed and democracy was re-introduced with the election in February 1999 of retired General Olusegun Obasanjo as President.

In April 2007, Umaru Musa Yar'Adua was elected President of Nigeria marking the first handover from one democratically elected government to another. Following the death of President Umaru Yar'Adua in 2010,

[11] IMF, Nigeria Country Report No.17/80 April 2017
[12] http://www.imf.org/external/datamapper/NGDP_RPCH@WEO/OEMDC/ADVEC/WEOWORLD/NGA
[13] UN World Population Prospectus, 2017 Revision

the then Vice President, Goodluck Jonathan, was sworn in as President in accordance with the Constitution and was re-elected in the general elections that were held in April 2011.

In April 2015, Muhammadu Buhari, a member of the All Progressives Congress, a retired General and previous governor of the North Eastern State, was elected as President. Mr. Buhari's election marked the first successful transition of power between opposing parties in Nigeria's democratic history and also the first time an incumbent, democratically elected president in Nigeria lost a re-election bid.

As part of his manifesto, President Buhari announced an intention to combat corruption and develop a fiscal framework that protects and encourages foreign investment in the Nigerian oil and gas industry, an industry that is of vital importance to Nigeria's economy, by encouraging indigenous Nigerian companies in the country's upstream oil and gas sector. President Buhari was previously the Federal Commissioner for Petroleum and Natural Resources and Chairman of the NNPC in the 1970s.

Economic environment

Nigeria is the largest economy in Africa. Until 2014, Nigeria had one of the fastest growing economies in Africa, growing at 4.3 per cent. in 2012, 5.4 per cent. in 2013 and 6.3 per cent. in 2014[14]. However, in view of its economy's dependency upon oil and the fall of oil prices since the third quarter of 2014, Nigeria's growth dropped to 2.7 per cent. in 2015 and, in the first quarter of 2016, the economy contracted by 0.36 per cent., and officially slipped into recession by the end of the second quarter of 2016. After five consecutive quarters of GDP contraction, the economy came out of recession with a 0.55 per cent. (year-on-year) growth in Q2 2017.

Nigeria's currency is the Naira. Since late 2014, the Central Bank of Nigeria (the "**CBN**") has taken a number of measures aimed at addressing the downward pressure on the Naira as a result of the steep decline in foreign currency revenue accruing to the Government of Nigeria from the oil and gas industry. These measures included currency devaluations and various currency restrictions. In June 2016, the CBN allowed the Naira to freely trade without a peg to the US dollar in order to relieve foreign exchange shortages and prevent further economic recession, effectively causing a devaluation of the Naira. The current CBN exchange rate is 305.5 Naira per one US dollar.

- *Capital Market*

The Nigerian capital market is primarily regulated by the NSEC while the Nigerian Stock Exchange, a self-regulatory organisation incorporated as a company limited by guarantee, is an exchange registered with NSEC and offers listing, trading, licensing and similar services for both equities and debt issuance. Additionally, the FMDQ OTC plc ("**FMDQ**"), another self-regulatory organisation, was registered by NSEC as an over-the-counter ("**OTC**") securities exchange. FMDQ has primary responsibility for the listing, trading and regulation of the OTC markets for fixed income (money, repos, commercial papers, treasury bills, and bonds), currencies and derivatives.

Overview of Nigeria's oil and gas industry

- *Legal and Regulatory Framework*

The key laws and regulations governing oil and gas activities in Nigeria include: (a) the 1999 Constitution (as amended); (b) the Petroleum Act; (c) the Petroleum (Drilling & Production) Regulations; (d) the Petroleum Profits Tax Act; (e) Deep Offshore & Inland Basin Production Sharing Contract Act; (f) Nigerian Oil and Gas Industry Content Development Act; (g) Deep Water Block Allocations to Companies (Back-in-Rights) Regulations; and (h) the Companies Income Tax Act.

Constitution of the Federal Republic of Nigeria 1999, Cap C23, LFN 2004

The Constitution vests the entire property and control of all minerals, mineral oils and natural gas in. under or upon any land in Nigeria, its territorial waters and the exclusive economic zone of Nigeria in the Federal Government.

[14] IMF, Real GDP growth – DataMapper, 2017

The Petroleum Act, 1969 (as amended) Cap P10, LFN 2004

The Petroleum Act (the "**PA**") covers various issues relating to the Nigerian petroleum industry. The PA provides for the different licences and leases that must be obtained in order to carry out petroleum operations. The PA gives the Minister the right to exercise general supervision over all operations carried on under licences and leases granted under the PA.

The primary regulator of the Nigerian oil and gas industry is the MPR and it performs its regulatory functions usually through the DPR (which is a department of the MPR). The DPR is responsible for supervising, regulating and monitoring petroleum activities in Nigeria through the enforcement of policies relating to all petroleum matters, licensing of all petroleum operations, including issuance of permits, and setting standards and guidelines for safe, efficient and effective control of such operations. The major contractual arrangements in the upstream oil and gas industry include direct concessions, unincorporated joint venture arrangements, production sharing contracts, marginal field concessions, and service contracts. Fiscal terms under each of these contractual arrangements vary, depending on the arrangement in use.

Nigerian National Petroleum Corporation Act 1977, Cap N123, LFN 2004

NNPC is the state oil corporation which was established on April 1, 1977. NNPC has broad ranging operational interests in refining, petrochemicals and products transportation as well as marketing. It is authorised to engage in commercial activities pertaining to the petroleum industry and also to enforce general control over the sector. The Minister is the chairman of NNPC and charged with overseeing the affairs of the NNPC. The duties of NNPC include: (a) exploration and prospecting for, working, winning or otherwise acquiring, possessing and disposing of petroleum; (b) purchasing and marketing petroleum, its products and by-products; and (c) engaging in activities that enhance the petroleum industry in the overall interest of Nigeria.

NNPC also operates through a number of subsidiary companies including: NPDC and Nigerian Gas Processing and Transportation Company, which owns and operates gas pipeline and grid infrastructure and the Nigerian Gas Marketing Company which is responsible to gas marketing. NNPC has a non-operated majority share of a number of joint ventures with international oil majors, typically holding a 60 per cent. interest (except for ventures with Shell, 55 per cent.), and operates through Joint Operating Agreements with its partners. NNPC reserves the right to become an operator of any field. The current Group Managing Director (Chief Executive) of the NNPC is Dr. Maikanti Kacalla Baru.

Petroleum Products Pricing Regulatory Agency Act (Establishment) No. 8 (2003)

This Act established the Petroleum Products Pricing Regulatory Agency ("**PPPRA**"), which is vested with the responsibility of determining the pricing policy of petroleum products and regulating the supply and distribution of these products for downstream oil firms. In addition, the PPPRA is expected to: (a) moderate volatility in petroleum products pricing, while ensuring reasonable returns to operators; (b) establish an information data bank through liaisons with all relevant agencies to facilitate informed and realistic decisions on pricing policies; and (c) prevent collusion and restrictive trade practices harmful to the sector.

Nigerian Oil and Gas Industry Content Development Act, 2010 ("Local Content Act")[15]

The Local Content Act provides a framework for increasing Nigerian participation in all sectors of the Nigerian oil and gas industry. The Act promotes the use of local goods, services and manpower in the development of projects within oil and gas industry. The Local Content Act prescribes minimum thresholds for Nigerian participation in oil and gas activities and also impacts the day to day management of companies operating in the oil and gas industry by imposing requirements concerning, among others, the use and involvement of Nigerian labour in their operations. The Schedule to the Act provides various types of goods and services or man-hours that must be quantified as Nigerian. It mandates preference for Nigerian companies undertaking projects in the oil and gas industry. It imposes a number of reporting obligations in respect of project development and general operations, which allow the Nigerian Content Development Monitoring Board, assess the company's compliance with the local content rules. The Act also deals with employment of Nigerians, technology transfer and the patronage of financial, insurance and legal service providers.

[15] Nigeria Oil and Gas Industry Content Development Act, Cap N124A, LFN, 2004

The Nigerian Oil and Gas Industry Content Development (Amendment) Bill 2015 ("Local Content Amendment Bill")

The Local Content Amendment Bill was passed by both the House of Representatives and the Nigerian Senate in 2015 and is currently awaiting presidential assent. The Local Content Amendment Bill when assented to by the President of the Federal Republic of Nigeria, will among others, redefine the threshold for a company to be considered as a "Nigerian Indigenous Company". The Local Content Amendment Bill seeks to distinguish between "Nigerian companies" and "*Nigerian indigenous companies*" with the former being companies that are 51 per cent. owned by Nigerians and the latter being a company which: (a) the entire issued share capital is owned by Nigerians; (b) the board of directors comprises only Nigerians; and (c) owns all its assets. It is not clear whether the Local Content Amendment Bill will become law in its current form since the 7th National Assembly which passed the Bill and sent the same to the President for his assent has been democratically dissolved.

Oil Terminal Dues Act[16]

This Act regulates the establishment of Oil Terminals, including terminals established on FPSOs, and imposes terminal dues on ships evacuating liquefied petroleum gas ("**LPG**") or liquefied natural gas ("**LNG**") for services provided by the terminal operator. The Act, also in tandem with the Oil in Navigable Waters Act (ONWA), regulates the discharge of LPG or LNG from ships and extends the application of the ONWA regime to all oil terminals even where they are located outside the area regulated by the ONWA.

Oil in Navigable Waters Act[17]

The ONWA and the regulations made pursuant thereto regulate the discharge of oil in prohibited areas of the sea, i.e., within 50 miles of the shore. However, the Oil Terminals Dues Act[18] extends the application of the restrictions under the ONWA regime to oil terminals wherever they are located and to the discharge of LPG and LNG. Therefore, the ONWA prohibits discharge of LPG from any FPSO into the water; it also prohibits discharges into other vessels at night[19].

Merchant Shipping Act[20]

The Merchant Shipping Act regulates the shipping industry generally. It deals extensively with the flagging, registration, deregistration, transfer and mortgage of ships. The Act also regulates seafarers and provides detailed rules on diverse issues, touching on safety at sea, cargoes, surveys, pollution, shipwrecks etc. the Act applies to all ships including FPSOs.

Coastal and Inland Shipping (Cabotage) Act[21]

The Cabotage Act reserves coastal trade for vessels owned and manned by Nigerians, which are built and flagged as Nigerian vessel. This Act prevents foreign vessels from participating in coastal trade unless they obtain a waiver from the Minister of Transport[22]. To ensure compliance with Cabotage rules, all vessels intending to participate in local trade are required to register for the Cabotage trade[23].

- *Petroleum Industry Bill*

Nigeria is pursuing a number of reforms targeted at restructuring its upstream and deregulating its downstream oil and gas industry, but the final form that these measures will take is currently uncertain and subject to political and economic influences. These initiatives include streamlining and revising obsolete laws, rules and policies that regulate operations in the industry. One of such reforms is the proposed PIB which has been pending before the National Assembly since 2008.

[16] Oil Terminal Dues Act, Cap 08, LFN 2004
[17] Oil Navigable Waters Act, Cap 06, LFN 2004
[18] Sections 6, Oil Terminal Dues Act
[19] Section 9, Oil in Navigable Waters Act
[20] Merchant Shipping Act, CAP M11, LFN 2004
[21] Coastal and Inland Shipping (Cabbotage) Act, CAP C51, LFN, 2004
[22] Section 3 and part III of Cabotage Act
[23] Section 22, Cabotage Act

In 2016, following the call from stakeholders for the PIB to be enacted into law piecemeal, the Federal Government resolved to split the PIB into four bills, namely (i) the Petroleum Industry Governance Bill 2016 ("**PIGB**"), (ii) the Fiscal Regime Bill, (iii) the Upstream and Midstream Administration Bill, and (iv) the Petroleum Revenue Bill. The Nigerian Senate passed the PIGB on 25 May 2017 and if passed by the House of Representatives, the bill would be presented to the President of the Federal Republic of Nigeria for his assent, after which it will take effect in accordance with the provisions of the Bill.

The PIGB seeks to provide for the governance and institutional framework for the Nigerian petroleum industry and creates a clear separation between policy, regulatory and commercial institutions and promotes transparency and accountability. The PIGB also seeks to establish the Nigeria Petroleum Regulatory Commission and the Ministry of Petroleum Incorporated. Within three months of the passage of the PIGB, all the staff, liabilities, assets and others will be transferred to the Nigeria Petroleum Regulatory Commission.

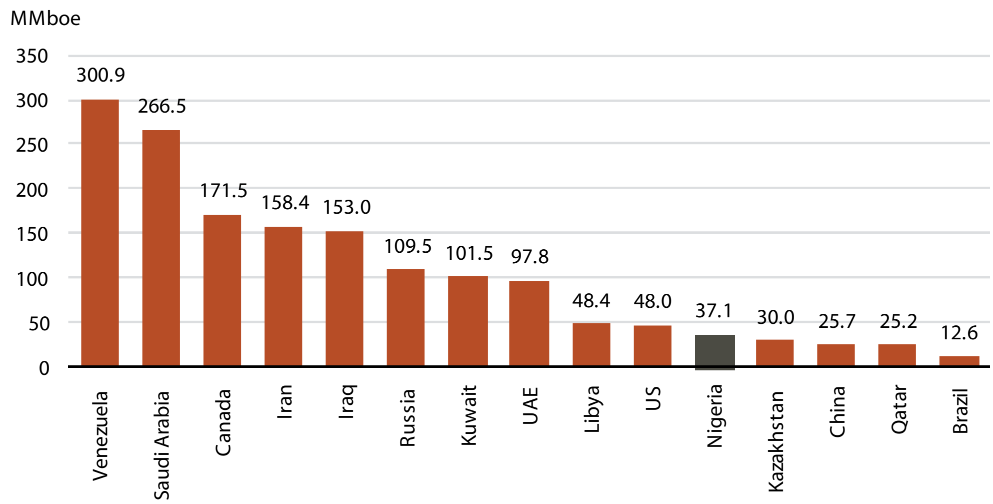
The Minister shall within three months after the PIGB is passed into law, take steps to incorporate two companies which may be called the Nigeria Petroleum Assets Management Company and the National Petroleum Company or such other names as may be available, respectively. The Ministry of Petroleum Incorporated and the Bureau of Public Enterprises will each hold (on behalf of the Nigerian Government) the shares of the two companies at the ratio of 51 per cent. and 49 per cent., respectively. Upon incorporation, the Nigeria Petroleum Assets Management Company shall be responsible for the management of the NNPC's oil and gas investments in the assets where the Government is not obliged to provide any upfront funding, while the National Petroleum Company shall be an integrated oil and gas company operating as a fully commercial entity across the value chain.

- *Reserves and Resources*

At the end of 2016, Nigeria's proven oil reserves were estimated at approximately 37.1 billion barrels, the second largest in Africa and eleventh largest reserves in the world[24]. In 2016 Nigeria produced on average 1.43 million barrels per day of oil and exported 25.2 billion cubic meters of gas[25].

Figure 13, Global Oil Reserves

Global Oil Reserves – Ranked by Country (Proven)



Source: BP Statistical Review of World Energy, 2017

The majority of Nigeria's oil and gas reserves are in the Niger Delta, with hydrocarbon reservoirs lying mainly within the Agbada formation which extends from onshore to shallow water. This formation includes interbedded sandstones and claystones, forming sequences of reservoirs and seals where oil and gas are then trapped by faulting and associated folding. The Akata Formation is a deeper water claystone unit which, together with claystones in the Agbada formation, form prolific source rocks for the delta. Additional oil reserves have also been discovered offshore in the Bight of Benin, the Gulf of Guinea and the Bight of Bonny.

[24] BP Statistical Review of World Energy, 2017
[25] OPEC Annual Statistical Bulletin, 2017

- *Oil production and development*

Oil was first discovered in Oloibiri, in Nigeria's Bayelsa State, in 1956[26]. The core producing areas cover approximately 60 per cent. of a total acreage of about 31,105 square kilometers[27]. Nigeria produces high quality sweet crude from approximately 193 operational fields. Nigeria joined Organisation of the Petroleum Exporting Countries ("**OPEC**") in 1971 and is one of fourteen member countries, it is the eighth largest oil reserves holder[28].

Historically, most oil production in Nigeria has come from relatively small individual onshore fields. However, production from deep water offshore fields has grown considerably in the past two decades, due to a number of factors that made deep water exploration more attractive to international oil companies. Deep water fields tend to be larger than onshore or shallow water fields, are less prone to security concerns that characterise operations onshore in the Niger Delta region and often have no NNPC direct funding interest, and thereby no associated funding constraints. In addition, the Government of Nigeria ownership share tends to be lower in the deep water fields than in the onshore and shallow water joint venture fields.

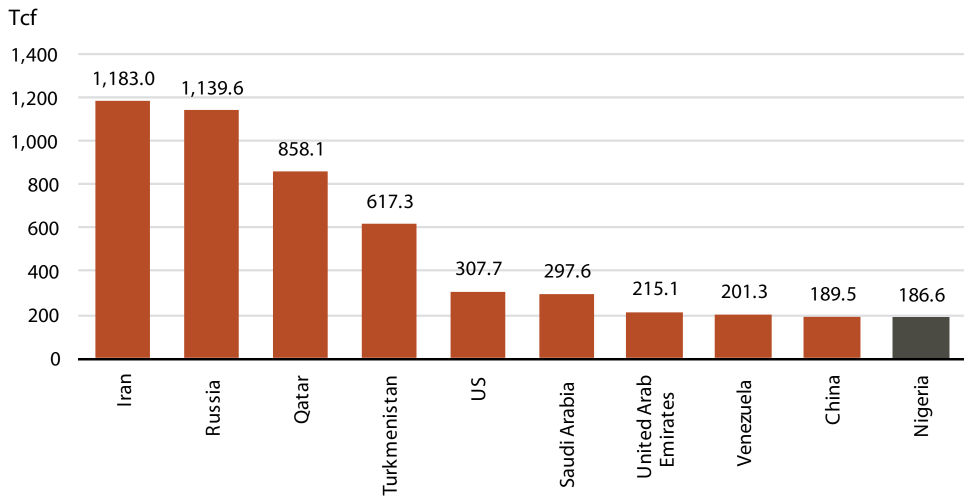
While most of Nigeria's resources lie in the Niger Delta, the Federal Government is looking to open up other parts of the country to oil and gas investments, including in the Nigerian section of the Central African Rift System where the Federal Government has in the 2016 budget appropriation earmarked NGN 39.4 billion for exploration activities in the north. NNPC has also sought to collaborate with the Republic of Niger and Savannah in the area of sharing of geological data to further boost the ongoing exploratory activities in the Nigerian section of the Central African Rift System.

- *Gas production and development*

As at 2016, Nigeria is estimated to hold 187 Tcf of proved natural gas reserves, which makes it the tenth largest gas reserve holder in the world and the largest in Africa[29].

Figure 14, Global Gas Reserves

Global Gas Reserves – Ranked by Country (Proven)



Source: BP Statistical Review of World Energy, 2017

The majority of gas produced in Nigeria is considered associated gas, a by-product of oil production. In 2016 Nigeria's gas production was 4 Bscf/d[30], which has significantly increased in recent times as a result of growing gas infrastructure projects to improve access and utilisation.

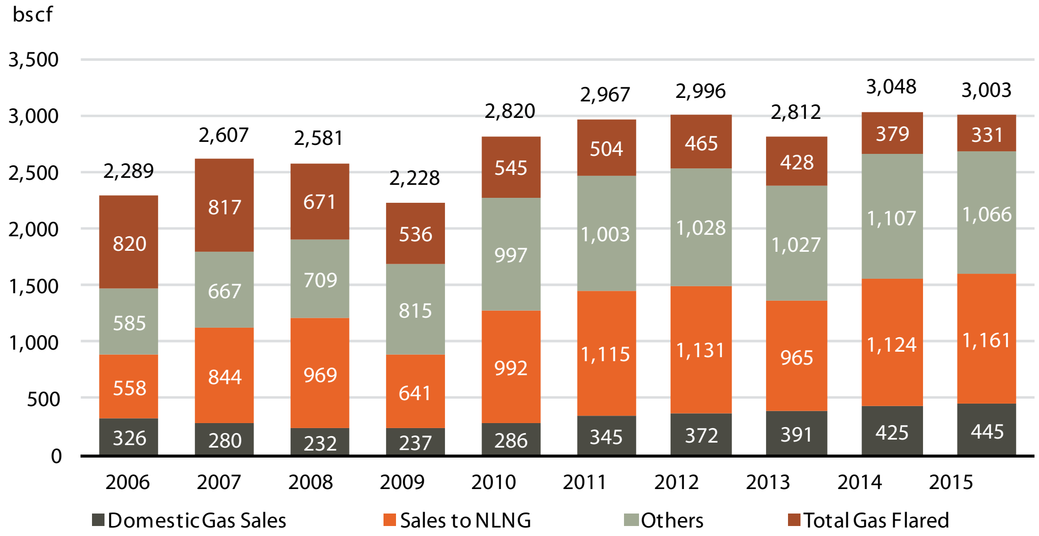
[26] OPEC, Nigeria Country Overview
[27] NNPC website
[28] OPEC, Nigeria Country Overview
[29] BP Statistical Review of World Energy, 2017
[30] BP Statistical Review of World Energy, 2017

In April 2017 the Nigerian National Petroleum Corporation (NNPC) announced it had succeeded in reducing gas flaring in the Country, by 26 percentage points in the last ten years from 36 per cent. to 10 per cent., pushing Nigeria down from the second highest gas flaring nation in 2006 to the seventh position in 2016. Under the new National Gas Policy, the Federal Government of Nigeria is targeting to end routine flaring by 2020[31].

Nigeria's domestic gas consumption is currently only circa 450 mmcf/d[32], as a large quantity of production is exported via the Nigeria LNG ("**NLNG**") terminal at Bonny Island where it is liquefied and subsequently exported overseas. NLNG is a key piece of gas infrastructure. The facilities were completed in 1999 and comprise of six processing trains, has an annual production capacity of 22.5 million tonnes of LNG and 4 million tonnes of LPG. A seventh train is under construction, which, when completed, would increase NLNG's total production capacity to 30 million tonnes per annum[33].

Figure 15, Nigerian Historical Gas Production and Utilisation

Nigerian Historical Gas Production and Utilisation



Source: DPR, Annual Oil & Gas Report 2014; Analysis: MPR Gas Policy Team 2016. Others: Fuel, Gas lift, Reinjection and NGLs

In recent times the Federal Government has demonstrated political support for developing natural gas resources, this includes the implementation of the Power Sector Recovery Program ("**PRSP**"). The Federal Government is actively encouraging oil companies operating in Nigeria to provide gas to independent power plants ("**IPPs**"), as part of the power sector reform plans. The Electric Power Sector Reform Act reviewed the generation, transmission and distribution of electricity in the country aiming to improve its performance. The IPPs will not only boost electricity supply but are also envisaged to provide necessary infrastructural support for economic growth, and also guarantee additional revenue to the upstream companies[34].

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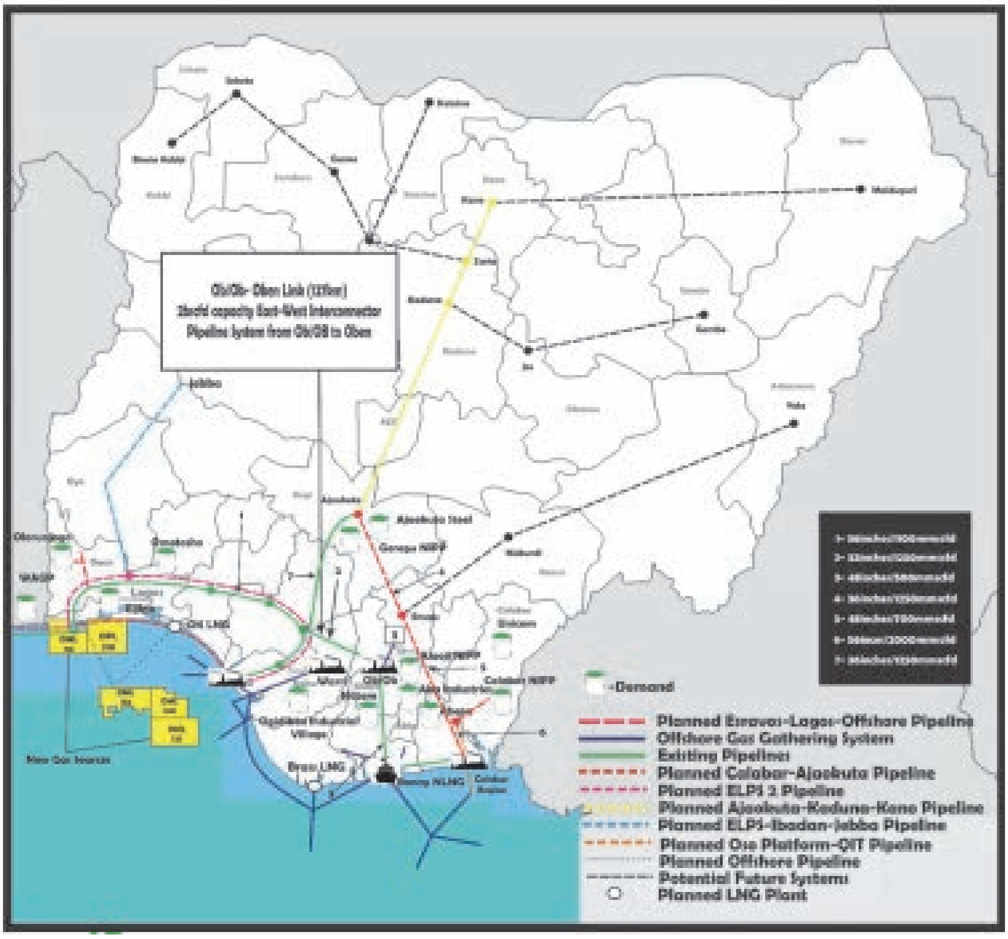
[31] http://www.worldbank.org/en/news/feature/2017/03/10/nigerias-flaring-reduction-target-2020
[32] National Gas Policy Approval Document, June 2017
[33] NLNG website, http://www.nlng.com/Our-Company/Pages/Profile.aspx
[34] http://nnpcgroup.com/nnpcbusiness/businessinformation/investmentopportunities/nigeriagas.aspx

Figure 16, Map of Nigeria

Map of Nigeria showing Gas Demand and Infrastructure



Source: NNPC

As a part of Nigerian government's policy, the implementation of the Nigerian Gas Master Plan began in 2008[35] (the "**GMP**"). The objectives of the GMP are to:

1. Stimulate the multiplier effect of gas in the domestic economy
2. Position Nigeria competitively in high value export markets
3. Guarantee the long term energy security of Nigeria

In meeting these objectives, the government hoped to facilitate the commercialisation of gas to power, fertilisers and other broad gas based industrialisation usages. The GMP was also set up to optimise the value of gas into higher end markets and ensure export market growth. The long term vision is to balance trans-generational needs and better plan the production and usage of gas resources.

In December 2016, the Buhari-led Federal Government launched the 7 Big Wins Initiative. This reinforced Nigeria's commitment to continue political support for reform. Subsequently in June 2017 the Federal Government approved the new National Gas Policy which had the foundations of the policy goals of the 7 Big Wins Initiative and has since overshadowed the GMP. The '7 Big Wins' are Niger Delta Security, Policy and Regulation, Business Environment and Investment drive, Transparency and Efficiency, Stakeholders Management and International Coordination, gas revolution and refineries, as well as production capacity. These initiatives are intended to be short and medium term priorities to grow Nigeria's oil and gas industry from 2015 to 2019[36].

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[35] http://nnpcgroup.com/nnpcbusiness/midstreamventures/nigeriangasmasterplan.aspx

[36] http://www.7bigwins.com/wp-content/uploads/2016/10/7-Big-Wins-Short-and-Medium-Term-Priorities-to-Grow-Nigerias-Oil-and-Gas-Industry-2015-2019.pdf

The National Gas Policy articulates the goals, strategies, and implementation plan of the Federal Government of Nigeria to reposition Nigeria as an attractive gas based industrialised nation through the prioritisation of local gas demand requirements. Particularly, the National Gas Policy is geared towards harnessing Nigeria's vast gas resources by removing the barriers undermining investment and development in the gas sector. If properly implemented, the National Gas Policy will drive the institutional reforms and regulatory changes necessary for Nigeria to evolve into a gas-based industrialised nation and consequently create an opportunity for financial institutions which would finance some of the gas development projects in Nigeria.

With a view to ensuring that gas prices are adjusted based on the applicable inflation rate, a new fiscal policy, which is to be embedded in a separate and complementary National Petroleum Fiscal Policy document, has been proposed for the Nigerian petroleum sector. The purpose of the fiscal framework is to make gas a standalone commodity, separate from oil. Hence, gas projects will be developed based on their economics and not dependent on or consolidated against oil taxation. The fiscal regime will be framed by fiscal rules of general application that are designed to ensure stability, progressivity, competitiveness, and cost efficiencies.

The policy outlines a clear focus to attract investment into the gas industry, including:

- Create regional hub for gas-based industries – fertilizer, petrochemical and methanol.
- Position Nigeria for self-sufficiency in these sectors and at least 5 per cent. global outputs.

The Gas Revolution aspect of Policy goals is an area of focus, the medium term objective is to deliver gas to support a three-fold increase in Nigerian generation capacity. In order to achieve this goal, the Federal Government has outlined a strategy to:

- reduce community disturbances and vandalism of gas and crude oil/condensate pipelines;
- develop and deploy a secure framework for investment in Gas to Power projects;
- pursue the implementation of identified seven key projects on a fast-track basis that will produce ~3.4bscf/d;
- engage and attract credible investors for financing the development of additional gas opportunities; and
- review gas to power strategy from flare down to non-associated gas development to delink gas to power from oil production[37].

Nigerian power sector

Nigeria suffers from an acute shortage of stable power supply. According to the Federal Government's Power Sector Recovery Program report of April 2017, Nigeria has 13,400MW of installed power generation capacity of which approximately 8,000 MW is mechanically available. Less than 4,000MW was dispatched on average over the last two years due to constraints in gas supply, electricity transmission, and distribution. The Federal Government has identified improvements in electricity generation, transmission and distribution infrastructure as a critical element required to enable the country to meet its economic growth and development objectives. However, according to the IMF, approximately one third of Nigeria's installed capacity is still not in operation. Also, according to the IMF, surveys show that 83 per cent. of businesses identified the lack of power as the biggest obstacle to doing business in Nigeria.

To address these power sector issues, the Federal Government made some significant investments in the sector and undertook a number of major reforms. For instance, the government under the auspices of the Nigerian National Integrated Power Project ("**NIPP**") built 10 gas-fired power plants as an emergency intervention scheme for the generation of electricity; the government also issued the Roadmap for Power Sector Reform setting out its reform plans for the power sector; the government unbundled the State electric sector monopoly about a decade ago and very recently completed the privatisation or grant of concessions of the various companies that were formed as a result of the unbundling (except the transmission company which remained under the control of the government). In spite of the privatisation, the power sector has continued to face some key challenges including liquidity constraints, low tariffs and collection levels, inadequate or weak transmission infrastructure, metering concerns, and many others issues which have generally affected negatively the rate of investments in the sector.

[37] http://www.7bigwins.com/wp-content/uploads/2016/10/7-Big-Wins-Short-and-Medium-Term-Priorities-to-Grow-Nigerias-Oil-and-Gas-Industry-2015-2019.pdf

With a view to resolving these challenges, the Federal Government on 22 March 2017 approved a Power Sector Recovery Plan in consultation with the World Bank Group. The objective of the Power Sector Recovery Plan ("**PSRP**") is to restore sector financial viability in the electricity market in its transitional phase post-privatisation.

Nigerian Power Sector Recovery Plan

The PSRP is a series of carefully thought out policy actions, operational and financial interventions to be implemented by the Federal Government of Nigeria to attain financial viability of the power sector, and the Nigerian Electricity Supply Industry ("**NESI**"). Among the key objectives of the PSRP is to improve power supply reliability to meet growing demand; to strengthen the sector's institutional framework and increase transparency; to implement clear policies that promote and encourage investor confidence in the sector; and to establish a contract-based electricity market.

At its core, the PSRP is comprised of the following components:

Financial interventions to fully fund historical and future sector deficits

The PSRP provides for: (i) the Federal Government's commitment to fund implied future sector deficits from 2017 to 2021 and execute a plan to fund the required electricity market support until tariffs attain cost recovery levels; (ii) how to eliminate historical sector revenue deficits through December 2016; (iii) how to eliminate historical debts of Ministries, Departments and Agencies ("**MDAs**") and automate future payments by ensuring that MDA debts are paid and implement payment mechanism for future electricity bills; (iv) restore cost reflective end user tariffs for over five years with increases to non-residential categories of consumers beginning in July 2017; (v) payment of Assurance Facility given that the CBN has provided a NGN701 billion (approximately US$2 billion[38]) facility to assist the NBET in meeting its payment obligations within generation invoices and ease the liquidity challenges; (vi) the World Bank Group has expressed its willingness to assist the FGN in preparing and supporting a credible power sector recovery programme. The World Bank Group has indicated potential support for the plan totalling up to US$2.5 billon as well as IFC investment and MIGA support to unlock additional US$2.7 billon in private investment.

Operational/technical interventions:

The PSRP provides for strategic roadmap to: (i) boost baseline power generation, transmission and distribution with the aim to ensure that a minimum baseline power generation of 4,000 MWH/H is guaranteed and distributed daily from 2017 to guarantee stability of the national grid; and (ii) ensure improved distribution company performance by designing balanced incentives to ensure aggressive Aggregate Technical, Commercial and Collection (ATC&C) loss reduction (e.g. through a metering programme), and distribution company financial restructuring and recapitalisation, implementation of credible Business Continuity Plans where required.

Governance interventions:

The PSRP also provides for strategy on: (i) how to restore proper sector governance of all key stakeholders in the sector through the appointment of qualified boards of directors to government agencies and appointment of qualified Federal Government representatives to the boards of distribution companies; (ii) improving sector transparency by establishing data driven processes for decision making across the sector's value chain; (iii) making contracts effective and starting the contract based market (i.e. the Transitional Electricity Market or TEM), formally addressing (through arbitration) all the legal issues that are impeding the activation of contracts; (iv) developing and implementing a clear communications strategy for PSRP with bespoke outreach to the public, judiciary, industry and legislators; (v) PSRP monitoring team – a dedicated team (Delivery Unit) has been set up and will be strengthened to coordinate and monitor the implementation of the PSRP.

Policy interventions

The PSRP also provides for measures to: (i) establish and implement foreign exchange (FX) policy for the power sector including FX rate for power sector and access to FX for power companies; (ii) increase electricity access by implementing off grid renewable energy solutions aimed at providing electricity supply to rural communities; (iii) encourage private sector investments, clarify the terms and conditions of

[38] NGN FX Rate 356, as at 7 December 2017

government support for private sector investment in generation, transmission and distribution including the timetable for transition to competitive procurement of generation; and (iv) issue tariff policy that will balance protection of electricity customers with the interests of investors by outlining a trajectory to cost recovery tariffs.

Competitive environment

International oil companies have been present in Nigeria since the 1950s, including a number of supermajors such as Shell, Chevron, ExxonMobil, Total and Eni. The international oil companies mainly focus on large scale projects and have gradually shifted focus from onshore oil investments to liquefied natural gas and deep water offshore exploration and production. NNPC has a majority share of several joint ventures involving international oil companies.

Over the last few years, also in conjunction with an increased focus of the Federal Government on indigenisation of the Nigerian oil and gas industry, a number of indigenous players have emerged, growing their asset base through acquisition of assets from international oil companies. In particular, a number of companies have successfully acquired assets from the majors. These recent developments advance the competitiveness of the Nigerian oil and gas sector.

As a result of increased need for capital consolidation, in recent years a number of majors have divested non-core assets in Nigeria, publically Shell, Petrobras and Chevron have announced (or completed) asset sales, creating an opportunity for local and international independents to invest:

- In October 2010, SPDC and other joint venture partners – Total E&P Nigeria Limited and Nigerian Agip Oil Company Limited agreed to sell their collective 45 per cent. interest in OML 26 to FHN 26 Limited for US$147.5 million.
- In December 2011, Neconde Energy Limited acquired a 45 per cent. interest in OML 42 in the onshore West Delta from SPDC joint venture partners Total E&P Nigeria Limited and Nigerian Agip Oil Company Limited for approximately US$585 million.
- In October 2014, Shell Petroleum Development Company of Nigeria (SPDC) joint venture partners Shell, Total SA, and Eni SpA agreed to sell their collective 45 per cent. interest in Niger Delta onshore producing block OML 25 to Nigerian producer Crestar Integrated Natural Resources for approximately US$500 million.
- In October 2014, Eroton Exploration & Production Co. Ltd. Consortium of Midwestern Oil & Gas, Suntrust Oil, and Mart Resources acquired a 45 per cent. interest in oil mining lease (OML) 18 in the Eastern Niger Delta from SPDC joint venture partners Shell, Total, and Eni for an estimated US$1.105 billion.
- In March 2015, Shell announced the completion of its sale of a stake in OML 29 and the Nembe Creek Trunk Line (NCTL) in the Eastern Niger Delta to Aiteo Eastern E&P Co Ltd for circa US$1.7 billion. Total and Eni had also reached agreements to divest their respective interest in the same assets.
- In June 2015, Chevron announced the sale of 40 per cent. interest in two Nigerian shallow water blocks to indigenous firm First Exploration & Petroleum Development Company Limited (First E&P).

- **Grant of Licences**

The ownership and control of all petroleum in, under or upon any lands in Nigeria is vested in the Federal Government[39], and the Minister is vested with the power to grant and renew the relevant licenses and leases to ensure the exploration, prospecting and disposal of petroleum in Nigeria. Subject to the provision of the Petroleum Act ("**PA**"), the Minister may grant or renew:

- A license, to be known as an oil exploration license ("**OEL**"). An OEL is non-exclusive licence to conduct preliminary exploration surveys. However, an OEL does not confer any right to the grant of an oil prospecting licence or an oil mining lease, and after the OEL expires, the company can apply for it to be converted to an oil prospecting licence (OPL) so that it can exploit petroleum. An OEL is granted for a term of one year and terminates on the 31 of December of the following year after the year of its grant with an option of renewal for a further one year[40]. The renewal is however subject to the fulfilment

[39] Section 1 (1) Petroleum Act (PA), CAP P8, Laws of the Federation of Nigeria, 2004
[40] Paragraph 3, Second Schedule, to the PA

of the obligations set out in the Petroleum Act, satisfaction of the Minister as to the work done and reports submitted. An application for renewal must be submitted at least three months before the expiration of the OEL.

- A license, to be known as an oil prospecting license ("**OPL**") which grants the title holder the exclusive right to explore and dispose of petroleum won during prospecting operations subject to the fulfilment of obligations imposed upon the grantee under the Petroleum Act. An OPL can only be granted to a company incorporated in Nigeria, and the holder of an OPL has the exclusive right to explore and prospect for petroleum within the area of his license. An OPL is granted for a term not exceeding five years, including any periods of renewal[41]. As such, if five years has elapsed in the term of any OPL, a renewal cannot be granted. Where the OPL title holder discovers oil in commercial quantities (during the subsistence of the licence) and it satisfies the conditions set by the Minister, the licence holder can apply for its OPL to be converted to an OML.
- A lease, to be known as an oil mining lease ("**OML**"), to search for, win, work, carry away and dispose of petroleum or otherwise treat petroleum discovered in or under the leased area[42]. An OML can only be granted to a company incorporated in Nigeria, and may be granted only to the holder of an OPL who has (i) satisfied all the conditions imposed on the licence or otherwise imposed on him by the Petroleum Act; and (ii) discovered oil in commercial quantities, and oil shall be deemed to have been discovered in commercial quantities by the holder of an oil prospecting licence if the Minister, upon evidence adduced by the licensee, is satisfied that the licensee is capable of producing at least 10,000 barrels per day of crude oil from the licensed area. The term of an OML is twenty years, and may be renewed for a similar term in accordance with procedures stipulated by the Petroleum Act. An OML title holder wishing to renew its licence must make its application for renewal not less than twelve months before the expiration of the lease. The renewal may be in respect of the whole of the leased area or any particular part thereof[43]. The renewal is subject to the payment of all rent and royalties due and the performance of all obligations owed by the Lessee under the lease[44].

Another means by which a company can obtain an oil and gas licence is by acquiring the interest of another company which already owns interest (subject to the consent of the Minister).

Every application for the grant and renewal of an OEL, OPL or OML must be in writing and addressed to the Minister in the appropriate form[45] and accompanied by the relevant information and documentation[46].

- **Revocation of Licences:**

There are three broad grounds under which OMLs or OPLs may be revoked. These are:

Ground One: Where the licensee/lessee becomes controlled directly/indirectly by a citizen of, or subject of, or a company incorporated in any country which is:

(a) a country other than the licensee's or lessee's country of origin; and

(b) a country, the laws of which do not permit citizens of Nigeria or companies incorporated in Nigeria or controlled directly/indirectly by citizens of Nigeria to acquire, hold and operate concessions on conditions which in the opinion of the Minister are reasonably comparable with the conditions upon which such concessions are granted to subjects of that country.

[41] Paragraph 6, First Schedule to the PA
[42] Section 2 (1) PA
[43] Paragraph 10, First Schedule to the PA
[44] Paragraph 13, First Schedule to the PA
[45] See Form A, Schedule to the Petroleum (Drilling and Production) Regulations (PDPR), made pursuant to the PA, L.N. 69 of 1969
[46] The information and documentation are required: (a) the prescribed fee (US$10,000 (for OPL application) and US$500,000 (for OML application); (b) 10 copies of a map on a scale or scales specified by the Department of Petroleum Resources (DPR) upon which is delineated in red the boundaries of the area in respect of which the application is made; (c) An adequate survey description of the boundaries of that area (at least one boundary corner being tied, in the case of an application for an oil mining lease, to an official survey control beacon, or an existing survey mark itself previously tied to an official survey grid) or, where the area has been blocked out or delineated and described by or on behalf of the Minister, a reference to the particulars of identification used by him or on his behalf; (d) Evidence of the financial status and technical competence of the applicant; (e) Details of the work which the applicant is prepared to undertake or a programme for carrying out any minimum working obligations imposed; (f) Details of the annual expenditure which the applicant is prepared to make on each area applied for; (g) The date on which he is prepared to begin operations after the grant of the OEL, OPL or OML to which the application relates; (h) Details of a specific scheme for the recruitment and training of Nigerians; (i) Evidence of the applicant's ability to market any petroleum produced; (j) Annual reports in respect of the applicant's oil exploration and production activities in the preceding three years; and (k) Any other information which the Minister may call for by notice in the Federal Gazette or otherwise

Ground Two: If in the opinion of the Minister, the licensee or lessee:

(a) is not conducting operations:

 i. continuously;

 ii. in a vigorous and business-like manner in accordance with the basic work programme approved for the licensee or lessee; and

 iii. in accordance with good oil field practice;

Ground Three: If in the opinion of the Minister, the licensee or lessee:

(a) has failed to comply with any provision of the Petroleum Act or any regulation or direction given thereunder or is not fulfilling his obligations under the special conditions of his license or lease; or

(b) fails to pay his due rent or royalties, whether or not they have been demanded by the Minister, within the period specified by or in pursuance of the Petroleum Act; or

(c) has failed to furnish such reports on his operations as the Minister may lawfully require.

- **Conditions to be satisfied before revocations**

The following conditions must be satisfied before a licence or lease can be revoked by the Minister under Grounds II and III above:

(a) Information to and Explanation by the Licensee/Lessee: The Minister shall inform the licensee or lessee of the grounds on which the revocation is contemplated and shall invite the licensee or lessee to make any explanation if he so desires.

(b) Opportunity to rectify: If the Minister is satisfied with the explanation, he may invite the licensee or lessee to rectify the matter complained of within a specified period.

If the licensee/lessee fails to sufficiently explain, respond to or rectify the matter complained of within the specified time, the Minister may then go ahead to revoke the OML or OPL.

Health and Safety Obligations

The Petroleum Act empowers the Minister to make regulations for safe working conditions and accident reporting and inquiries. The Mineral Oil Safety Regulations 1962 (the "**MOSR**") made pursuant to the Petroleum Act 1969, provides very specific health and safety compliance requirements for holders of OPL or OML and their employees. These provisions can be broadly broken down into four main requirements as follows: (a) duties of OPL and OML holders to appoint managers and other competent persons to monitor its operations and prevent or reduce any health hazards or safety incidents; (b) duties of holders of OMLs and OPLs (through the managers), to provide safety equipment and to enforce specific safety and health protocols to be observed by other employees during operations; (c) duties of employees to observe safety regulations (the MOSR and any internal safety protocol), to prevent the creation of health and safety hazards and to report any accidents; and (d) detailed specifications on equipment used in the drilling and production operations of the OML.

Under the Petroleum (Drilling and Production) Regulations 1969, licensees and lessees must maintain all apparatus and appliances used in their operations, boreholes and wells capable of producing petroleum in good repair and condition. Operations must also be conducted in accordance with methods and practices acceptable to the DPR as good oil field practice.

The Petroleum Refining Regulations, 1974 provide for the health and safety of persons involved in petroleum refining operations. The regulations govern: the use of safety clothing and appliances; the provision of medical and first aid facilities; and the taking of precautions with dangerous parts of machinery and training of inexperienced workers.

The Petroleum Regulations, 1967 deal primarily with downstream petroleum operations and prescribe safety standards for the transportation, storage, importation and handling of petroleum products.

The DPR has developed an offshore safety permit personnel accountability system for the tracking of personnel working in onshore and offshore locations, and managing installations owned and/or operated by Oil and Gas operators and contractors in Nigeria. The fundamental purpose of the system is to account for and save the lives of the oil and gas workers through effective training in compliance with the Minerals Oils (Safety) Regulations and International Codes, Standards and Best Practices.

Part II D of the DPR Environmental Guidelines and Standards for the Petroleum Industry 1991 (as revised in 2002 ("**EGASPIN**")) makes provisions for steps to ensure safety of lives and protection of property in the course of the use of explosives during seismic activities by operators.

Decommissioning Obligations

Operators of an OML or OPL must seek the written permission of the DPR before abandoning operations or resuming abandoned operations. Within two months after the terminating or surrendering a part or whole of the OML or OPL, the licensee (this is typically done by the operator) is obligated to: (a) plug every borehole which the DPR may indicate in the manner specified by the DPR; (b) deliver in good order, repair and condition and fit for further working, all productive boreholes or wells to the Minister (unless the DPR requires the licensee or lessee in writing to plug them as he may direct or as provided by these Regulations) together with all casings and other appurtenances to the boreholes and wells which are below the Christmas tree and cannot be moved without causing injury to the said boreholes or wells; (c) fill up and fence all holes (other than boreholes and wells) and excavations made in the relevant area as required by the DPR; and (d) to the like extent take reasonable steps to restore as far as possible to their original condition the surface of the relevant area and all buildings and structures thereon which have been damaged in the course of his operations[47].

Every borehole or well which is intended to be abandoned must be securely plugged by the relevant OML or OPL holder unless the DPR otherwise permits. Such borehole or well must also be handled in strict compliance with the abandonment (decommissioning) programme approved by the DPR[48].

Furthermore, in line with contemporary practices and in a bid to establish and set environmental standards in the Nigerian petroleum industry, the DPR established the EGASPIN, to cater for all facets of petroleum activities, including the decommissioning of oil and gas facilities[49].

The EGASPIN provides that decommissioning programs shall be planned, with their objectives and implementation drawn up during the project initiation and design phases. As such, at the start of any project, the decommissioning programme should have been drawn up. Such objectives must incorporate remediation/restoration programs. Additionally, if the Environmental Impact Assessment/Baseline/Sea-Bed Survey Report was not prepared for the project prior to project implementation, the licensee/lessee/operator shall provide the following: (a) an Environmental Evaluation (post-impact) Report, specific to the project/activity; and (b) a Decommissioning Plan Report, specific to the project/activity (Only this Report is required if the Environmental Impact Assessment/Baseline/Sea-Bed Survey Report was prepared for the project prior to project implementation).

Licensees/Lessees shall thereafter appropriately decontaminate, dismantle and remove structures from oil and gas installations and facilities after such have been abandoned and decommissioned. As regards duration, the decommissioning activities (for facilities completely shut down and/or abandoned) shall commence at least one year after abandonment and be completed within six months.

Under the DPR Procedure Guide for the Construction and Maintenance of Fixed Offshore Platforms (which regulates all offshore platforms) made pursuant to the Petroleum Drilling Regulations, the firm, corporation or other organisation employed by owners to conduct operations on the platform are fully responsible for decommissioning. Particularly, five years prior to the end of the economic life of the field, the Operator is obliged to submit a comprehensive disposal plan for the offshore facilities for approval by the DPR.

[47] Regulation 46 (1) & (2) PDPR
[48] Regulation 36 (2) PDPR
[49] Decommissioning of Oil and Gas Facilities – Part VIII – G of the EGASPIN

Penalty for non-compliance: Failure to comply with obligations created under the Petroleum Act or any of the regulations made pursuant to it may result in revocation of the relevant OML or OPL in accordance to paragraph 25 of the 1st Schedule of the Petroleum Act. However, in practice, revocation of an IOC's license as a form of penalty is rarely implemented.

Nigerian Fiscal Regime

Both the Uquo Field and the Stubb Creek Field are taxed under the new entrant concession field terms, with the Nigerian Government take consisting of royalties and Petroleum Profits Tax ("**PPT**") for liquids and Corporate Income Tax ("**CIT**") for gas. Profits are taxed at the asset level.

Pioneer status grants to eligible companies, among other things, a three year tax exemption with a further two year extension available after a satisfactory performance by the company in the first three years. Under the previous Pioneer Status regime conducted by the Nigerian Investment Promotion Commission, *mineral oil prospecting and production* was listed under the eligible activities for Pioneer Status grant and the Uquo Field obtained Pioneer Status under said regime. The term of the Uquo Field Pioneer Status will expire in 2019. The status was intended to incentivise upstream investment by indigenous companies with the expectation that profits would be reinvested in the business.

Based on a recent review of the pioneer incentive scheme embarked on by the FGN which culminated in the issuance of Gazette No. 61, Volume 102 of 27 May 2015, and more recently, the New Additions to the Pioneer List dated 07 August 2017, as well as the New Guidelines for the Issuance of Pioneer Status Incentive – August 2017, *mineral oil prospecting and production* has been excluded from the list of activities and industries which are entitled to pioneer status.

(a) *Liquids tax and royalties*

- **Royalty** – Pursuant to the Marginal Field Fiscal Regulations 2005, the royalty rate for marginal fields ranges from 2.5 per cent. to 18.5 per cent. depending on the average production rate of the field.

Figure 17, Nigerian Government Royalty Rates

Government royalty rates for liquids revenue

Gross Oil Production	*Royalty*
0-5,000b/d	2.5%
5,001-10,000b/d	7.5%
10,001-15,000b/d	12.5%
>15,000b/d	18.5%

Source: Lloyd's Register, Competent Persons Report: Niger Delta Assets

- **Overriding royalty** – An overriding royalty is payable on marginal fields in Nigeria to the original owners of the licences.

Figure 18, Nigerian Overriding Royalty Rates

Overriding royalty rates for liquids revenue

Gross Oil Production	*Royalty*
0-2,000b/d	2.5%
2,001-5,000b/d	3.0%
5,001-10,000b/d	5.5%
10,001-15,000b/d	7.5%
>15,000b/d	negotiated

Source: Lloyd's Register, Competent Persons Report: Niger Delta Assets

- **Education tax** – This tax is charged at 2 per cent. of annual Assessable Profits and is deductible for the calculation of PPT.

- **PPT** – For new producing licences, a concessionary PPT rate of 65.75 per cent. is applicable in respect of the first five years of production, and thereafter, the standard rate of 85 per cent. will apply.

- **NDDC Levy** – A levy of 3 per cent. of the total annual budget of any onshore and offshore oil producing company is payable to the NDDC by any company operating in the Niger-Delta area.

(b) *Gas tax and royalties*

- **CIT** – Profits generated from gas sales less operating costs explicitly linked to gas production are taxed at the general Nigerian CIT rate of 30 per cent.

PART 6

NIGER COUNTRY OVERVIEW

Country overview
The Republic of Niger (Niger) is a large state in West Africa covering a surface of 1,267,000 sq km, landlocked between Nigeria and Benin to the South, Burkina Faso and Mali to the West, Algeria and Libya to the North and Chad to the East. Niger was previously a French colony and gained independence in 1958, its capital is Niamey. Niger has a population of over 20 million people, and substantial mineral resources, yet remains one of the most underdeveloped countries in the world, as circa 80 per cent. of its land area lies in the Sahara Desert. Niger has an average GDP per capita of US$420 (as estimated by the International Monetary Fund (IMF)[50]). Niger is a constitutional democracy with a fast-growing economy and western-facing government. The IMF estimates GDP growth of 4.2 per cent. in 2017 and 4.7 per cent. in 2018[51]. The country's applicable currency is the West Africa CFA (Communauté Financière d'Afrique, "Financial Community of Africa") Franc.

Political environment overview
Since 1999, Niger has had a relatively stable and democratic government, except for a short period of military coup d'etat in 2010. The country has since enjoyed relative political stability under a new constitution established in 2010, which has led to a significant increase in foreign direct investment.

The most recent presidential elections were held on 21 February 2016, which led to the re-election of President Mahamadou Issoufou for another five–year mandate. He has been President since 2011, and has been described as a Western ally who is focused on ensuring increased security and improving national infrastructure. President Issoufou is the leader of the Nigerien Party for Democracy and Socialism (PNDS-Tarayya), a centre-left leaning social democratic party founded in 1990.

Economic environment overview
According to the UN's Human Development Index, Niger is one of the world's least developed countries[52] and saw a 3.8 per cent. annual population growth in 2016, which is expected to continue over the coming years. Foreign direct investment, which has been mainly focused on the country's natural resources sector, has however been increasing substantially since the mid-2000s and, as a result, the Nigerien economy is expected to grow strongly in the medium term with the IMF estimating GDP growth of 4.2 per cent. in 2017 and 4.7 per cent. in 2018[53]. This growth is expected to be primarily driven by increased output in the uranium mining industry, currently dominated by France-based nuclear multinational, Areva Inc., along with the continued development of the oil and gas industry. There has been increased investor interest for uranium extraction in Niger; the country is the fourth-ranked uranium producer in the world[54]. Niger has two operating uranium mines contributing to 7.5 per cent. of the world's total uranium production. Areva has an interest in both assets:

- a 34 percentage interest in COMINAK (Compagnie Minière d'Akouta), the largest underground uranium mine in the world; and
- a 63.6 percentage interest in Société des Mines de l'Air (SOMAIR) was formed in 1968 and started production from the Arlette/Arlit deposit in 1971.

The oil and gas industry is expected to become the largest single contributor to GDP within the foreseeable future, as the country moves to net exporter status. The industry has seen significant investment from CNPC as well as from Savannah Petroleum plc, who have been the two major sources of international investment into the industry.

Despite this strong forecast growth rate, Niger remains highly exposed to exogenous shocks due to its high dependence on uranium exports (which account for approximately 58.1 per cent. and 45.4 per cent. of all

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[50] http://www.imf.org/external/datamapper/NGDPDPC@WEO/OEMDC/ADVEC/WEOWORLD/NER (IMF World Economic Outlook, October 2017, GDP per capital, current prices, US dollars per capita)

[51] http://www.imf.org/external/datamapper/NGDP_RPCH@WEO/OEMDC/ADVEC/WEOWORLD/NER/OEMDC/ADVEC/WEOWORLD/NER?year=2017

[52] UN Development Programme Human Development Report 2016. Niger is ranked 187th out of 188 States

[53] http://www.imf.org/external/datamapper/NGDP_RPCH@WEO/OEMDC/ADVEC/WEOWORLD/NER/OEMDC/ADVEC/WEOWORLD/NER?year=2017

[54] World Nuclear Association, http://www.world-nuclear.org/information-library/country-profiles/countries-g-n/niger.aspx

exports respectively for last quarter of 2016 and first quarter of 2017[55]) and the agricultural sector's susceptibility to extreme weather. The country's membership of the Western African Economic and Monetary Union ("**WAEMU**") and the Economic Community of West African States ("**ECOWAS**"), as well as strong support from the IMF, in terms of an approximate US$134 million extended credit facility, serve partly to mitigate the risks related to the decrease of the value of oil products and uranium and the increase of investments related to defence and safety[56]. This participates in the increase of investor confidence.

In April 2014, Niger adopted a new investment code that lays out the general principles governing the reception and protection of foreign investment, as well as the incentives available for approved projects. The code allows for negotiated tax breaks provided by the Ministry of Commerce on a case-by-case basis. Most investors benefit from special tax treatment and tariff protection for varying periods depending on the level and location of investment. The investment code guarantees equal treatment of investors regardless of nationality. The investment code offers incentives for sectors the government deems key to economic development[57].

Oil and gas industry overview

Exploration activities in the Agadem Rift Basin of Niger have been ongoing since the 1970s. Between 1974 and 2004, five discoveries were made from a total of 25 exploration wells, all of which were drilled based on 2D seismic backed geological models. Companies active at that time included Elf, Texaco, Conoco, Sun Oil Esso and Petronas. In 2008, CNPC acquired the exploration rights to the Agadem License Area through paying a US$300 million signature bonus to acquire the five existing discoveries and the exploration rights to the area for eight years. Over the period 2008 – 2016, CNPC made an additional 95 discoveries and established a 2P reserve base of circa 1 bn bbls. In doing so, CNPC clearly demonstrated the pro-business environment of Niger, given the magnitude of the work programme pursued in a relatively short period of time, which included: (1) drilling more than 225 exploration, appraisal and development wells; (2) acquiring approximately 18,000 km of 2D seismic and 13,000 sq km of 3D seismic; and (3) building a 462.5 km pipeline and the 20kboe/d Zinder refinery, achieving first oil for the country in 2011 with the commencement of production from the Sokor and Goumeri fields.

In early 2013, CNPC completed the sale of 20 per cent. of the License Area to CPC Corporation (the Taiwanese national oil company). In July 2013, the first period of exploration of the Agadem License Area by CNPC ended, and circa 50 per cent. of the acreage was returned to the public domain under the terms of CNPC's Production Sharing Contract ("PSC") with the Government of Niger. In July 2014, Savannah Petroleum plc signed a PSC with the Government of Niger for the R1/R2 license area, followed by the signature of the R3/R4 PSC in July 2015. Savannah now has circa 50 per cent. of the Agadem Rift Basin under license.

Niger's domestic oil consumption is relatively low (currently circa 7,000 bopd), meaning a significant proportion of existing production is exported, and the majority of oil expected to be produced from future developments is expected to be exported. CNPC has committed to implement an export solution to allow discovered resources at Agadem to be commercialised. Potential export routes include an extension to the existing Chad-Cameroon pipeline, a pipeline to the Kaduna refinery in northern Nigeria as well as a potential trucking solution to northern Nigeria. The export of crude oil is currently expected to commence by the end of 2020.

National legislative framework

The national legislative framework of petroleum activities in Niger is greatly influenced by the evolution of the local industry. The law pertaining to the Niger petroleum code was amended several times in 2004, 2006 and 2007 (Law number 2007-01 dated 31 January 2007, which implementation modalities are provided for in Decree N°2007-082/PRN/MME dated 28 March 2007). A bill on the Petroleum Code has recently been adopted by the members of the Niger National Assembly, with the aim of replacing the Petroleum Code dated 2007.

The Nigerien oil industry is governed by the Ministry of Petroleum, which also implements the policies. The Ministry represents the government in all upstream oil and gas industry dealings and investments. SONIDEP

[55] Index of foreign trade laid down by the National Institutes of Niger for last quarter of 2016, published in March 2017; Index of foreign trade laid down by the National Institutes of Niger for the first quarter of 2017, published in May 2017

[56] Niger is involved in the fight against terrorism in Nigeria and Sahel region since February 2015

[57] U.S. Department of State, 2015 Investment Climate Statement – Niger

is the National Downstream Oil Company whose sole mission is to ensure proper distribution of refined products to all parts of the Nigerien territory and export any excess refined production from the Soraz refinery. The Petroleum Code is enforced by the agents of the Ministry of Petroleum which is divided into five departments:

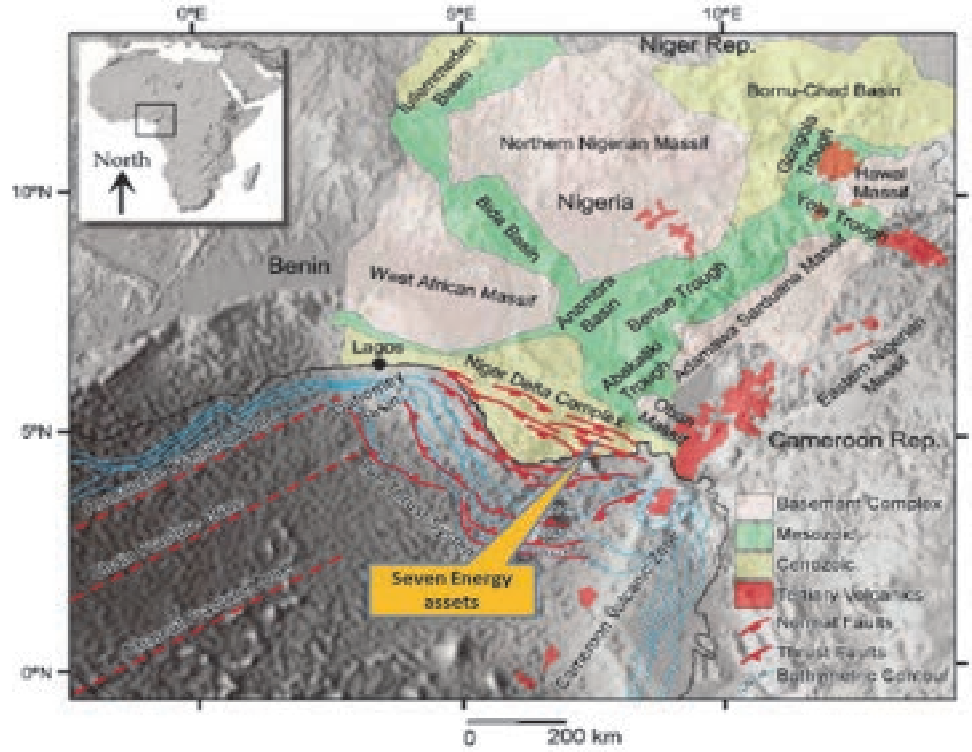
- Hydrocarbon Exploration and Production;
- Refining, Transport and Distribution;
- Environment, Health and Safety;
- Economy and Tax; and
- Valuation and Follow up of Petroleum Investment.

PART 7

NIGERIAN ASSET SUMMARY

The Seven Assets are located onshore in southern Nigeria, in the south east of the prolific petroleum system of the Niger Delta (Figure 19). In addition to its high-ranking world petroleum status (eleventh largest reserves in the world) with some 37.1 billion barrels oil reserves as of end 2016, Nigeria has the second largest gas resources in the African continent with some 187 trillion cubic feet (Tcf) of nominal reserves (BP Statistical Review of World Energy, June 2017), and these have remained largely unexploited. Associated gas has traditionally been flared in the absence of any developed gas market but policy and economic development are now moving rapidly towards a favourable climate for gas commercialisation.

Figure 19, Niger Delta – Regional Setting



Source: Modified from Corredor et al., the American Association of Petroleum Geologists, Copyright 2005

The Niger Delta Basin is a highly prolific, mature petroleum province, extending from the onshore delta onto the marine shelf and slope (Figure 19). Late Jurassic to Early Cretaceous rifting controlled initial development of the delta and its main depocentre, while the Tertiary aged sedimentary pile has been prograding south-westwards since Eocene times (ca. 55 Ma). The Tertiary age Niger Delta now covers an area of about 75,000 sq km, and has a sedimentary thickness of up to 10 km.

The assets under consideration are located in the south-eastern part of the onshore delta, which is dominated by normal faults trending northwest to southeast and down-thrown to the southwest towards the basin depocentre. Traps are present in a variety of combinations of rollover structures with different faulting styles.

The principal petroleum bearing formation in the Niger Delta Basin is the Miocene age Agbada Formation, which contains multiple hydrocarbon bearing sand units, interbedded with extensive mudstones which form seals to the reservoir units. Reservoir sands are generally quite thick (of the order of 10 to 50 m) with excellent reservoir quality and with good lateral continuity. The interbedded mudstones are also thick and form good seals against faults. Sufficient burial of the pro-delta, marine shales of the underlying Akata Formation has allowed maturation for oil and gas generation, and these provide prolific source rocks to the area providing light, paraffinic crude.

Upon completion of the proposed Acquisition, the Enlarged Group will hold in the South-East region of Nigeria:

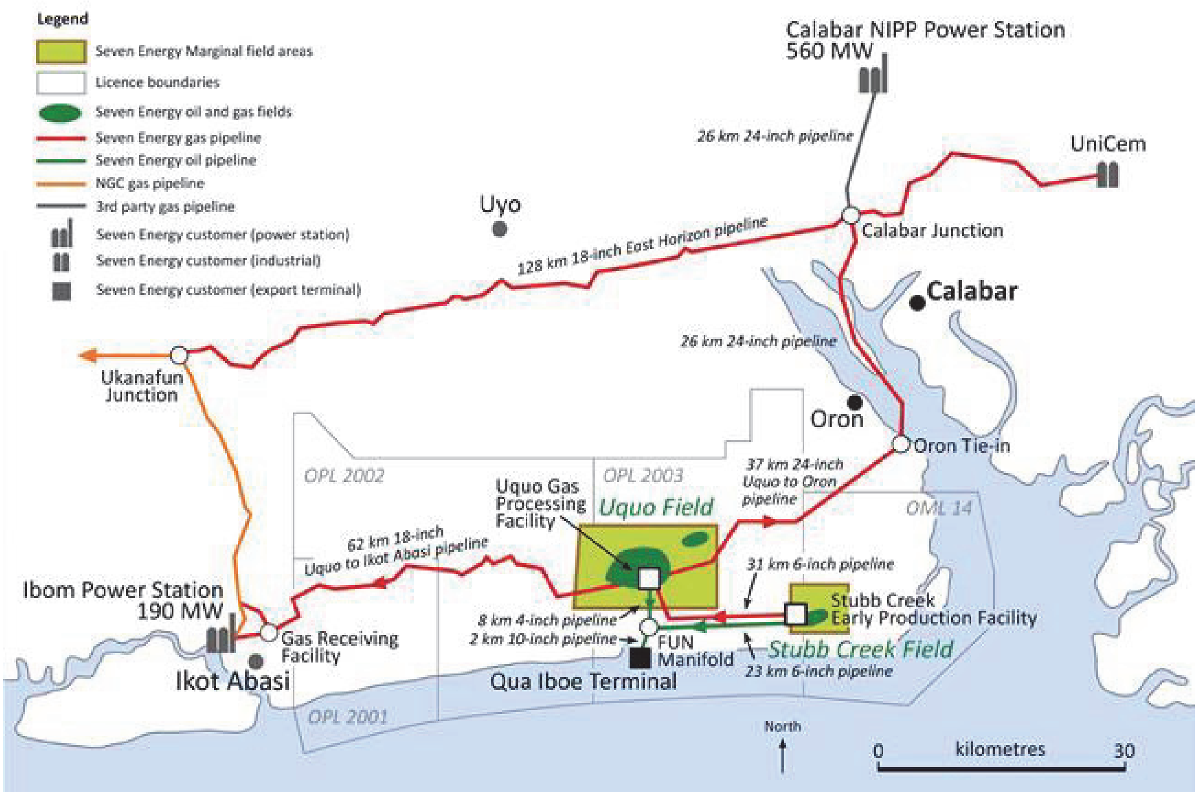
- a 40 per cent. participating interest in the Uquo Field;
- a 62.5 per cent. interest in Universal, which holds a 51 per cent. participating interest in the Stubb Creek Field; and
- a 20 per cent. carried interest in Accugas Limited, the owner of the Accugas Midstream Business.

Frontier, an indigenous Nigerian E&P, is the operator of the Uquo Field and Universal is the operator of the Stubb Creek Field.

Asset	*Operator*	*Participating Interest (%)*	*Status*	*Licence Expiry Date*	*Licence Area*
Uquo	Frontier	40	Production	2026	171 sq km
Stubb Creek	Universal	31.9	Production	2026	42 sq km

Both of these assets are currently in production. The Exxon-Mobil QIT, through which oil from both the Uquo Field and Stubb Creek Field is exported, lies a short distance to the south of the Uquo Field (Figure 20). A number of large industrial gas consumers are located in this part of the Delta, including power stations at Ibom and Calabar, a cement plant at Calabar, and other users closer to Port Harcourt; these are connected to the Uquo Field via Accugas Limited's gas pipeline network.

Figure 20, Seven Energy assets and Infrastructure, South East Niger Delta



Source: Seven Energy

Gross oil and gas reserves, and net attributable reserves in the two upstream assets, as determined by LR in the Nigeria CPR, are shown below. Attributable volumes are calculated from an economic model, incorporating all the elements of the fiscal terms applicable to the fields. The combined assets amount to 9.2 MMbbl oil and 495.5 Bscf gas in net attributable 2P (Proved plus Probable) reserves.

Figure 21, Oil and Gas Reserves from Nigeria CPR (as of 1 November 2017)

	Gross on License			*Net Attributable*			
	1P	*2P*	*3P*	*1P*	*2P*	*3P*	*Operator*
Oil and Liquids Reserves (MMstb)							
Uquo	4.2	7.8	12.4	3.5	6.7	9.0	FOL
Stubb Creek	9.6	17.1	26.7	1.3	2.5	4.2	UERL
Total MMstb	13.8	24.9	39.1	4.8	9.2	13.2	
Gas Reserves (Bscf)							
Uquo	364.5	565.0	788.1	319.7	495.5	634.3	FOL
Total Bscf	364.5	565.0	788.1	319.7	495.5	634.3	

Source: Adapted from Nigeria CPR

Contingent Resources, as determined by LR in the Nigeria CPR, are summarised below. Additional gas at the Uquo Field, and the large gas resource at the Stubb Creek Field, are considered by LR to have a high probability of future commercial development (>75 per cent.). 2.3 MMbbl of oil and 247.9 Bscf of gas are attributable to the Enlarged Group in the 2C, "Best Estimate" case:

Figure 22, Oil and Gas Contingent Resources from Nigeria CPR (as of 1 November 2017)

	Gross on License			*Net Attributable*			*Chance of*	
	1C	*2C*	*3C*	*1C*	*2C*	*3C*	*Development*	*Operator*
Oil and Liquids Resources (MMstb)								
Uquo	1.0	2.5	5.1	0.9	2.1	3.0	25%–75%	FOL
Stubb Creek	0.7	1.0	1.4	0.1	0.2	0.3	>75%	UERL
Total MMstb	1.7	3.5	6.5	1.0	2.3	3.3		
Gas Resources (Bscf)								
Uquo	45.0	72.5	115.6	39.5	63.6	79.6	>75%	FOL
Stubb Creek	364.9	515.3	680.3	129.4	184.3	238.1	>75%	UERL
Total Bscf	409.9	587.8	795.9	168.9	247.9	317.7		

Source: Adapted from Nigeria CPR

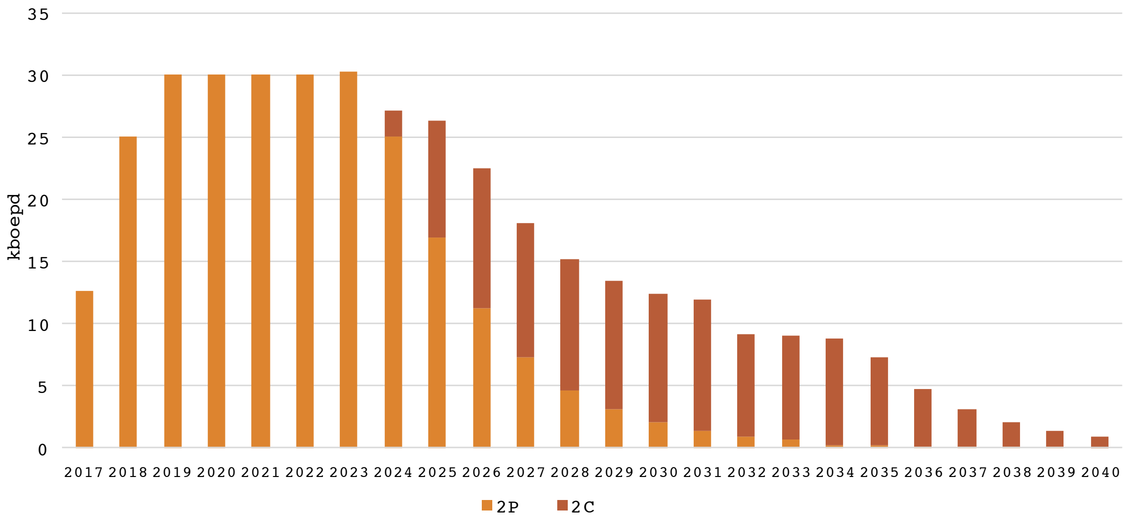
Estimates of the NPV, based on discounted cash flow of future net revenues, after deduction of capex, opex, taxes and royalties derived from the Seven Energy share are shown below. The NPVs are calculated using a discount rate of 10 per cent. and an oil price assumption of US$60/bbl (real January 2018, inflated at 2 per cent. p.a. thereafter). All relevant assumptions are provided in the Nigeria CPR.

Figure 23, NPV10 for Reserves Net to Seven Energy from Nigeria CPR (as of 1 November 2017)

	Proved	*Proved + Probable*	*Proved + Probable + Possible*
South East Niger Delta (US$ million)			
Uquo Liquids	61.1	103.1	141.3
Uquo Gas	261.0	397.3	494.6
Stubb Creek Oil	26.1	47.6	55.3
Total	348.2	548.0	691.2

Source: Adapted from Nigeria CPR

Figure 24, Production Profile Net to Seven Energy from Nigeria CPR (as of 1 November 2017)



1. Uquo Marginal Field

SUGL holds a 40 per cent. participating interest in the Uquo Field, with its joint venture partner Frontier holding the remaining 60 per cent. operated interest. Under the terms of its joint operating agreement and technical services agreement with Frontier, SUGL acts as technical and funding partner to Frontier and as project manager for the Uquo field development. SUGL holds an 87.7 per cent. gas and 85 per cent. oil revenue interest in the asset.

The Uquo Field was designated as "Marginal" and awarded to Frontier in 2003. Uquo is a significant gas development, with some associated oil production, and is located onshore in OML 13 in Akwa Ibom State, South East Niger Delta, around 10 km from QIT (Figure 20). The Uquo Field, with several associated prospects, is contained within the Uquo Field licence area, the area of which was recently enlarged and now encompasses both the field and most of the undeveloped Discoveries and Prospects identified (see Figure 25).

The Uquo Field was discovered by Shell in 1958, who identified oil and gas in a number of discrete sands in the Miocene Agbada Formation at Uquo-1 between 6,800ftss (2,100m) and 8,000ftss (2,400m). Appraisal drilling in the 1970's encountered mainly gas, although one well was subsequently completed as an oil producer. The Uquo Field was awarded to Frontier in the 2003 Marginal field round, with Seven acquiring its interest in 2009. Nine wells have been drilled to date on the field, which have proven four separate structures with 19 hydrocarbon bearing reservoirs (14 gas, 4 oil and 1 potential oil) all of which lie within the Early Miocene Agbada Formation.

The Uquo Field has primarily been developed as a gas field, with four wells (Uquo-2, -4, -7 and -8/8ST) completed as gas producers in the D1.0 and D2.0 reservoirs, and just one well (Uquo-3) completed as an oil producer in the slightly deeper D5.0 reservoir. An exploration/appraisal well, Uquo-9/9ST, was drilled in 2014 on an upthrown fault block to the north east, and discovered gas in Agbada C6.0, D1.0 and D1.5 sands, as well as oil in deeper D1.6 and D7.0 sands, but this "Uquo NE" discovery has yet to be developed. The license area is covered by a high quality 3D seismic survey, acquired in 2006-2007.

Current average gas production is around 89 MMscf/d (October 2017), with cumulative production of 82 Bscf of gas (to end October 2017) since first gas was achieved in Q4 2013. Commercial production from the field commenced in January 2014. Current liquids facility capacity at the field is approximately 2,000 kbopd (October 2017), with liquids evacuated via pipeline to the QIT.

Near-term operational plans at the field include the completion of the Uquo-9 oil well and an 11 km pipeline tie-in to the Uquo CPF in 2018, which is expected to deliver oil production of c.1,800 bopd, and the drilling of one new gas well to maintain GSA DCQs. The Nigeria CPR estimates 2018 gross capital expenditures on the Uquo Field at US$33.5MM.

The Uquo Field is low-cost, with LR having assessed life of field gross capital and operating costs to be US$1.7/boe and US$1.3/boe respectively on a forward basis.

1.1 ***Gas and oil accumulations***

The gas and oil accumulations proven at Uquo Field lie in four distinct areas, corresponding to structural highs within the overall down-to-south fault complex, with varying gas/water and oil/water contacts within the different Agbada Formation sands (see Figure 26).

- *Uquo-2/4 area*

This dip closed rollover has gas proven in five of the Agbada D sands, with gas-initially-in-place (GIIP) of around 475 Bscf (Best Estimate), at depths between 5,900ftss (1,800m) and 7,550ftss (2,300m). There are two wells on production (Uquo-2 and Uquo-4) from the D2.0 and D1.0 sands respectively. Upside exists in un-completed D sands and in the overlying Agbada C section, where an additional 36 Bscf GIIP is identified in the C9.0 sand.

- *Uquo-3 area*

This is a dip and fault-bounded footwall accumulation, with gas in Agbada D1 sands between c. 5,900ftss (1,800m) and 6,100ftss (1,900m) and oil/gas in the deeper D5 below c. 6,900 ftss (2,100m). The Best Estimate GIIP is 239 Bscf (mainly in D1.0), with initial oil-in-place (STOIIP) of 5.5 MMstb in the D5.0 sand. Two gas wells are currently producing from the D1.0 sand (Uquo-7 and -8ST). Upside potential exists in up-dip “attic gas” and in associated extensions to the west.

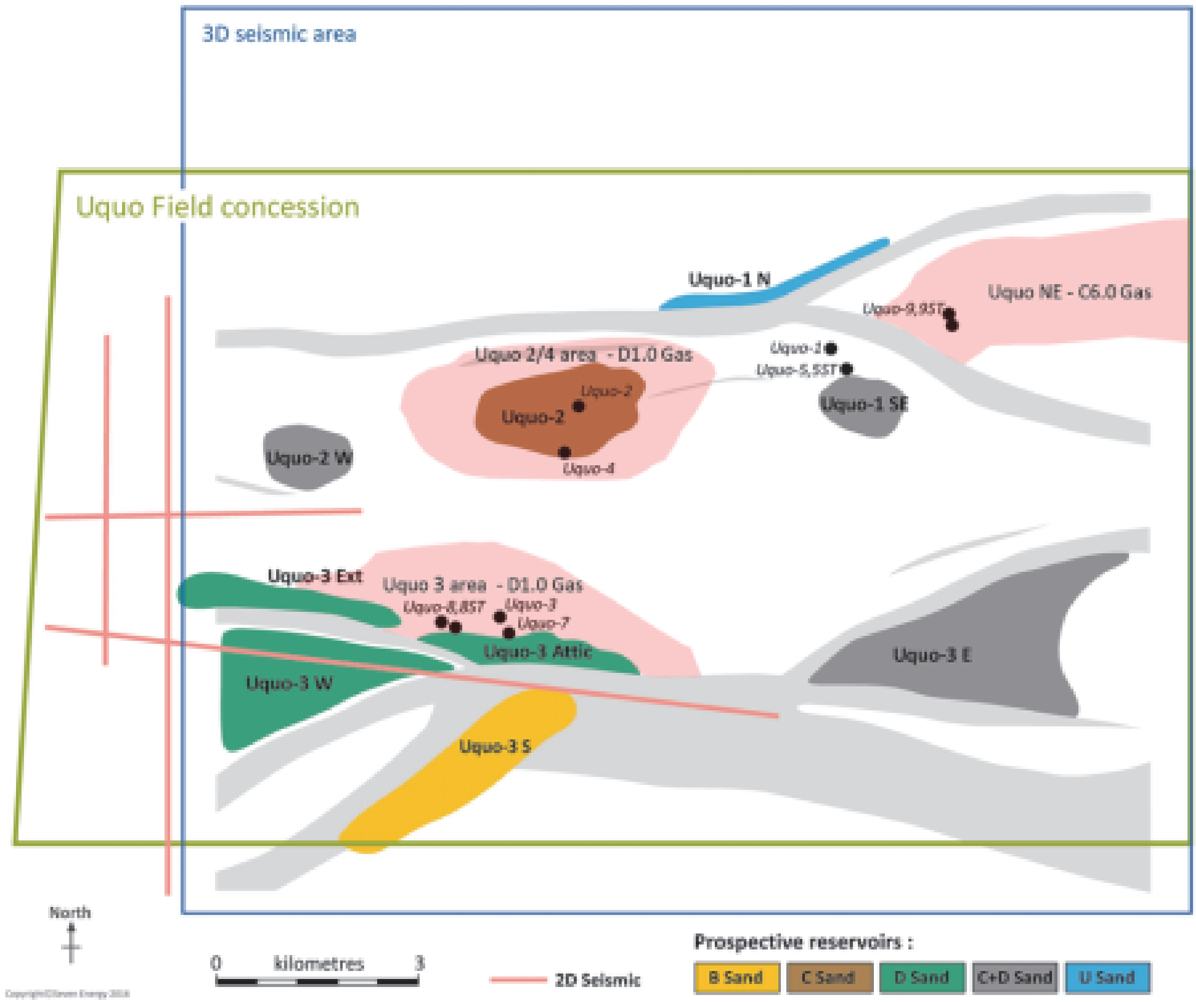
- *Uquo-5 area*

This is a small dip-closed rollover in the hanging wall of an E-W fault, which was tested in the original discovery well and its Uquo-5 twin. A small volume of gas has been identified in the C8.5 sand (Best Estimate GIIP 14 Bscf), but this is not included in any development plan. Oil in the deeper U5.0 sand, below c.7,900ftss (2,400m), was seen in the discovery well but remains un-appraised, and there is thought to be some up-dip exploration potential in the C and D sands.

- *Uquo NE area*

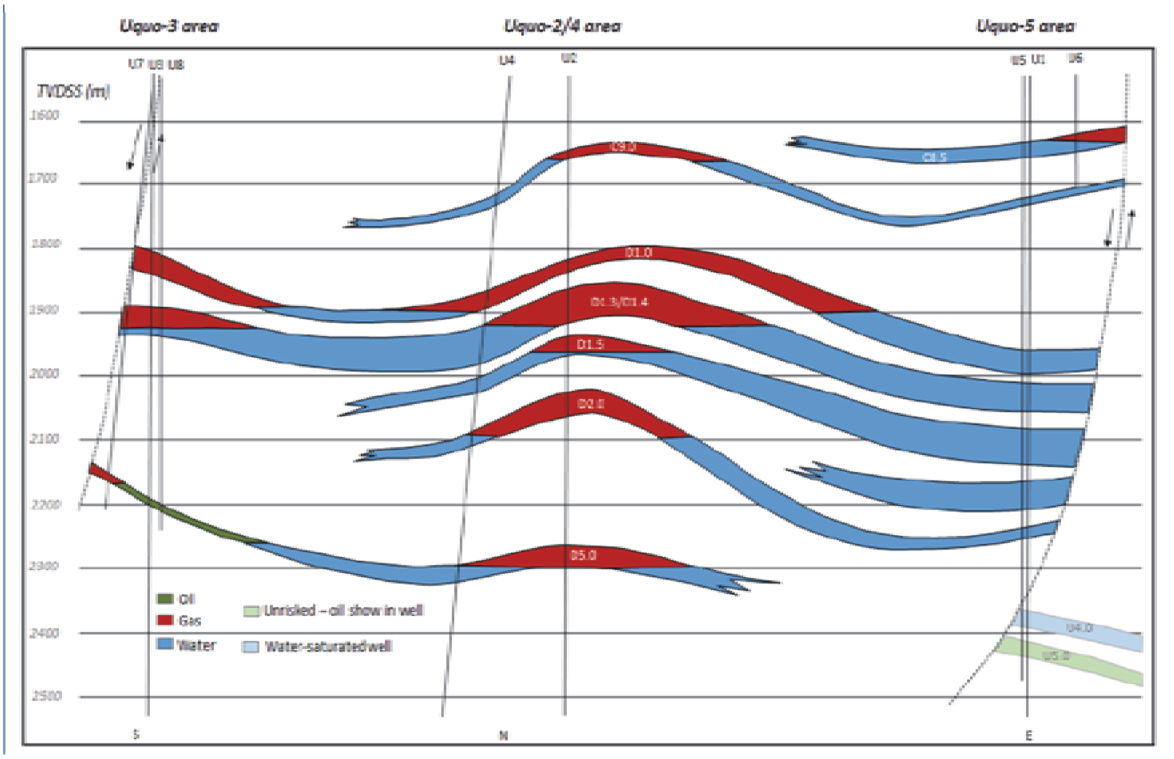
This is a large upthrown fault block to the north east, with fault and dip closure. Oil and gas was discovered in the Uquo-9/9ST well The Best Estimate GIIP on the license is around 144 Bscf (in the Agbada C6.0 at around 4,200ftss (1,300m), and D1 sands), with 21 MMstb STOIIP in the deeper D1.6 and D7.0 sands.

Figure 25, Uquo Marginal Field, Discoveries and Prospects



Source: Nigeria CPR

Figure 26, Uquo Marginal Field, schematic cross-section



Source: Nigeria CPR

Gas

A full development of these gas accumulations, estimated to have a total GIIP in excess of 800 Bscf (Best case), is thought to require seven wells; four existing wells, three new wells, and two of these wells to be worked-over. Based on these assumptions, an independent assessment estimates around 565.0 Bscf could be recovered in the Proven plus Probable case, of which 495.5 Bscf are attributable to the Company's interest. Cumulative gas production to 31 October 2017 was 82.0 Bscf. Gas volumes within known gas sands which are not currently planned for completion and development are classified as Contingent Resources, and constitute a substantial upside.

Figure 27, Uquo Marginal Field – Gas Reserves and Contingent Resources (as of 1 November 2017)

	Gross on License			*Net Attributable*		
Gas (Bscf)	*1P/1C*	*2P/2C*	*3P/3C*	*1P/1C*	*2P/2C*	*3P/3C*
Reserves	364.5	565.0	788.1	319.7	495.5	634.3
Contingent Resources	45.0	72.5	115.6	39.5	63.6	79.6

Source: Adapted from Nigeria CPR

Oil

The Uquo-3 well started production in February 2015. The well is in terminal decline and no reserves are currently assigned.

The Uquo NE discovery well, Uquo-9, is currently suspended, but is planned to be completed as an oil producer in the D1.6 sand during 2018. Over 7 MMstb of 2P Reserves have been assigned to the Uquo NE area in the D1.6 sand, with a upside potential designated as Contingent Resources in the deeper D7.0 sand, which will require additional drilling.

Figure 28, Uquo Marginal Field – Oil Reserves and Contingent Resources (as of 1 November 2017)

	Gross on License			Net Attributable		
Oil (MMbbl)	*1P/1C*	*2P/2C*	*3P/3C*	*1P/1C*	*2P/2C*	*3P/3C*
Reserves	4.2	7.8	12.4	3.5	6.7	9.0
Contingent Resources	1.0	2.5	5.1	0.9	2.1	3.0

Source: Adapted from Nigeria CPR

1.2 ***Exploration Prospects***

A number of un-drilled structural closures and un-evaluated sands have been identified in the immediate area of the Uquo Field, and have been classified as notional "Exploration Prospects" (see Figure 29). Given the multiple reservoir horizons identified in this prolific area the exploration risks are thought to be moderate, with Chance of Success assessed at over 50 per cent. in some cases, and seismic reprocessing is planned to further derisk. Together they provide a significant potential upside for the field, with over 800 Bscf of un-risked potential GIIP.

Figure 29, Exploration prospects

Gross GIIP (Bscf)	*Low*	*Best*	*High*	*Chance of Success***
Uquo 1SE	55.7	84.8	139.9	0.50
Uquo 2	13.6	25.4	51.0	0.73
Uquo 2W	71.3	88.4	103.7	0.57
Uquo 3E Licence	151.5	221.7	335.7	0.35
Uquo 3S Licence	114.8	154.3	200.1	0.66
Uquo 3W Licence	72.5	115.2	204.1	0.18
Uquo 3 Extension	10.2	15.1	22.6	0.14
Uquo 3 Attic	13.3	23.4	42.6	0.17
Uquo 3 Fault Zone	49.0	83.8	93.9	0.20
Uquo 1N	6.1	14.7	35.2	0.18
Total Licence*	558.0	826.8	1,228.8	

* Arithmetic sum

** "Chance of Success" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource. A High Chance of Success indicates a high chance of discovering hydrocarbons in sufficient quantity for them to be tested to surface.

Source: Adapted from Nigeria CPR

1.3 ***Production Facilities***

Gas produced from the Uquo Field is processed through the Uquo CPF, which is owned by Accugas Limited. It is expected that the Enlarged Group will hold a 20 per cent. carried interest in Accugas. A detailed description of the assets held by Accugas Limited are contained in Section 4 of this Part 7.

Liquids from the Uquo Field are transported via a 4-inch 8 km pipeline to the FUN Manifold facilities before being on-sold to ExxonMobil.

2. Stubb Creek Marginal Field

The Enlarged Group is expected to hold an interest in the Stubb Creek Field through its 62.5 per cent. subsidiary, Universal. Universal holds a 51 per cent. operated interest in the field, with Sinopec holding the remaining 49 per cent. interest. Stubb Creek lies within the area OPL 276, formerly OML 14, near the mouth of the Cross River (Figure 20).

Discovered by Shell in 1971, the Stubb Creek Field was awarded to Universal as a Marginal field in 2003. Seven acquired its interest in 2009 and 2010 through a two-stage acquisition of a 62.5 per cent. shareholding in Universal, and thereby gained control over the operatorship of the field by virtue of its shareholding and management position. The Stubb Creek Field was brought into commercial production in 2015 using the Stubb Creek EPF, which is capable of processing oil at a gross rate of c.3 kbopd.

Oil and gas accumulations at the Stubb Creek Field are found in a series of sands of the Miocene Agbada Formation, located in a broadly E-W oriented rollover anticline structure in the downthrown hanging wall of a prominent E-W fault. A total of nine wells have been drilled in the Stubb Creek Field; four exploration and appraisal wells drilled by Shell between 1971 and 1983, and five development wells drilled, tested and completed ready for production by the current operator Universal between 2007 and 2009. Oil is evacuated via the FUN Manifold to QIT.

The focus of appraisal and development to date has been the oil at the Stubb Creek Field, located in the deeper sands on the south side of the field; production started in February 2015, with 2.0 MMstb produced to date from three wells (to end October 2017). However, since the involvement of Seven Energy in the asset, attention has turned to the large but un-appraised gas resources in the shallower section. The field is covered by a 3D seismic survey acquired in 2005/06 by Universal. Data quality is excellent, allowing accurate structural mapping, and identification of amplitude anomalies related to hydrocarbon distribution.

It is anticipated that in 2018 that the existing Stubb Creek EPF will be debottlenecked, to increase oil production capacity to c.5 kbopd. The contingent gas resources are currently expected to be developed in 2025 (Best Estimate Case), as the Uquo Field gas production declines below DCQ, and to be tied back to the Uquo CPF via a new 31 km pipeline. The Nigeria CPR estimates 2018 gross capital expenditures on the Stubb Creek Field at US$25.8 million.

2.1 ***Oil and gas accumulations***

- *D Sands*

  The deeper D sand section of the Agbada formation forms a dip and fault bounded closure adjacent to a complex series of E-W normal faults on the south side of the field area. Oil is found in the Upper D3 sands, at depths below 6,050ftss (1,800m). A thin oil rim (12ft) also occurs at the base of the deepest overlying C9 gas sand at around 4,700ftss (1,400m), but only the Upper D3 sand is thought to be commercially viable for oil development. This unit has excellent reservoir properties, and is estimated to contain STOIIP of 38.9 MMstb (Best Estimate). The C9 oil rim is estimated to contain 32.6 MMstb STOIIP (Best Estimate), but is not included in any recoverable reserve estimates.

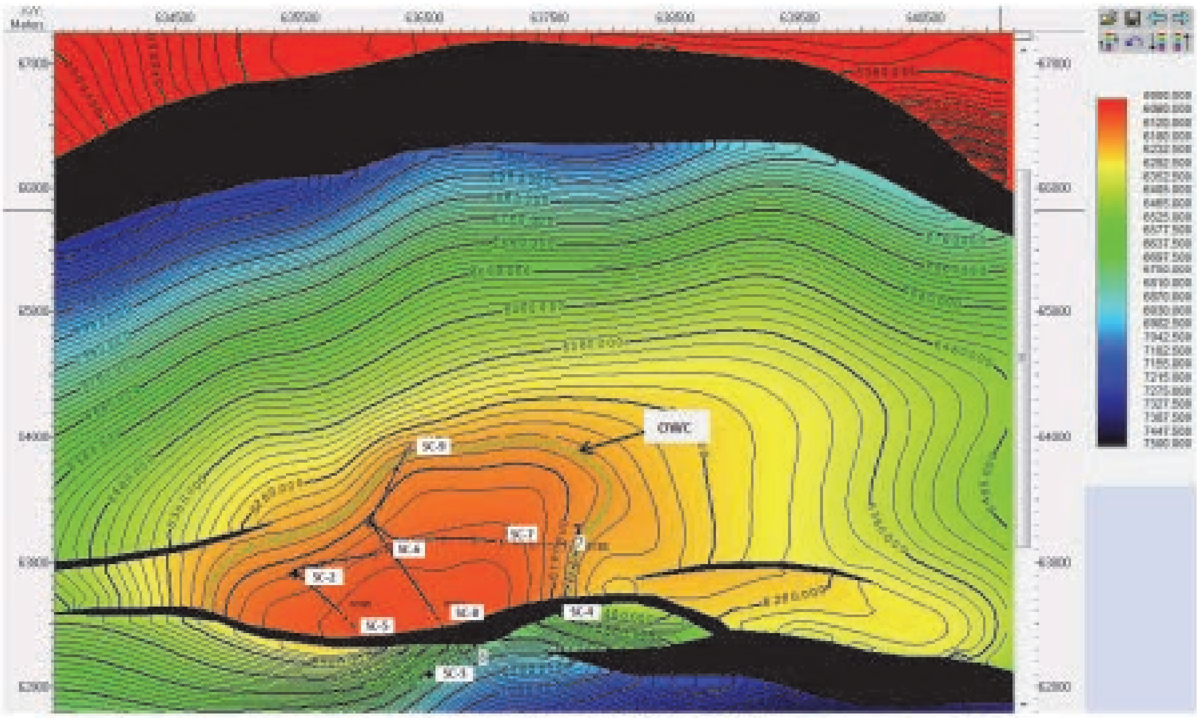
- *C Sands*

  The Agbada C gas sands occur at depths of 3,600ftss (1,100m) to 5,000ftss (1,500m), shallower than the oil accumulations in the D sands. Gas occurs in the Upper and Lower C3, C7, C8 and C9 sands (see Figure 30). The majority of the GIIP – 466 Bscf (Best Estimate) – is located in the C3 sands, of which the shallowest, Upper C3, is the largest. These gas accumulations are only penetrated by a single well, the SC-1, although the gas volumes are quite clearly defined by their seismic amplitude signature on 3D seismic data. An additional 150 Bscf GIIP is estimated in the C9 sand, overlying the thin oil rim; this has been penetrated by four wells in the oil development area, and the accumulation is also well defined on 3D seismic.

Oil

Reserves have been assigned only to the Upper D3 sand (Figure 12), which has been developed with five wells (SC-2, -5, -6, -7 and -8), of which three are on currently production at a combined rate of 2,760 bopd (October 2017). The SC-9 well, on the northern down-dip edge of the accumulation, has been completed as a water injector. These wells, together with the addition of another injector in 2018, should be sufficient to fully develop the Upper D3 oil pool with about a 50 per cent. recovery factor. Production is expected to increase to around 4,650 bopd by Q4 2018 following the completion of production facilities. Gross remaining 2P reserves are 17.1 MMstb, of which 2.5 MMstb are attributable to Seven's interest.

Figure 30, Stubb Creek Marginal Field – Top UD3 Depth Map



Source: Nigeria CPR

Figure 31, Stubb Creek Marginal Field – Oil & Condensate Reserves and Contingent Resources (as of 1 November 2017)

	Gross on License			*Net Attributable*		
Oil (MMbbl)	*1P/1C*	*2P/2C*	*3P/3C*	*1P/1C*	*2P/2C*	*3P/3C*
Reserves	9.6	17.1	26.7	1.3	2.5	4.2
Contingent Resources	0.7	1.0	1.4	0.1	0.2	0.3

Source: Adapted from Nigeria CPR

Gas

There are no gas reserves currently assigned to the Stubb Creek Field, as the main gas accumulations have not been flow tested or appraised and there is no approved field development plan at this stage. These are however high quality gas reservoirs; a recovery factor of 80 per cent. is anticipated, with high individual well productivity, and over 500 Bscf (Best Estimate case) have been classified as Contingent Resources of which around 184.3 Bscf are attributable to the Seven Energy interest.

Figure 32, Stubb Creek Marginal Field – Gas Reserves and Contingent Resources (as of 1 November 2017)

	Gross on License			*Net Attributable*		
Gas (Bscf)	*1P/1C*	*2P/2C*	*3P/3C*	*1P/1C*	*2P/2C*	*3P/3C*
Reserves	0	0	0	0	0	0
Contingent Resources	364.9	515.3	680.3	129.4	184.3	238.1

Source: Adapted from Nigeria CPR

2.2 *Production Facilities*

Oil production at the Stubb Creek Field is currently via the Stubb Creek EPF, which has facilities to treat and stabilise oil for export by pipeline, via a 23 km 6-inch line constructed in 2010-2011, to the FUN Manifold located north of the QIT. About 1.7 MMscf/d of associated gas are currently produced and used to power the facilities, with excess flared on site. The Stubb Creek Field to Uquo Field pipeline system also includes a 31 km 6-inch gas pipeline, which is planned to be utilised to route associated gas to the Uquo CPF. This pipeline is owned by the Stubb Creek JV.

The Stubb Creek EPF, which has a current capacity of 3,000 bopd, is expected to be debottlenecked to give a maximum capacity of 5,000 bopd. Seven Energy is currently forecasting the debottlenecking to be complete by September 2018, including the drilling of a second water injection well.

Plans for production facilities to allow exploitation of the gas resources at the Stubb Creek Field are likely to include a larger pipeline to the Uquo Field. Gas from the Stubb Creek Field is expected to fulfil any GSA commitments to existing Accugas Limited customers, as production from the Uquo Field declines below GSA DCQs.

3. FUN Manifold

The FUN JV participants are Frontier (Uquo Field), Universal (Stubb Creek Field) and Network Exploration and Production Limited (Qua Iboe Field OML/13). The FUN JV owns the 25,000 bopd capacity common oil evacuation infrastructure which allows the individual crude production from each member's field to be comingled and evacuated to the QIT. The FUN Manifold is connected to the QIT via a 2 km 10-inch pipeline, which is owned by the FUN JV.

4. Accugas

The Enlarged Group is expected to acquire a 20 per cent. carried interest in Accugas. Accugas Limited focuses on the marketing, processing, distribution and sale of gas to the Nigerian market. Currently, Accugas Limited supplies gas to power station and industrial customers in South East Nigeria, however the Enlarged Group expects additional high value incremental demand from regional industrial customers as evidenced by Heads of Terms which have been signed.

The Accugas Midstream Business comprised of:

- 200 MMcfpd Uquo CPF;
- circa 260 km network of gas pipelines; and
- circa 600 MMcfpd gas distribution capacity.

Accugas Limited buys raw gas from its sole current supplier, the Uquo JV, at a price of US$1.7/Mscf, and sells this gas to three separate customers at a weighted average price of US$3.5/Mscf. This price is expected to increase by an average of over five per cent. p.a. over the next six years due to price indexation clauses which are included in the GSAs.

Uquo CPF's first commercial gas delivery began in January 2014 to the 190 MW Ibom power station. At present, Accugas Limited has three long-term GSAs in place, the largest of which is with the 560 MW Calabar NIPP power station. Together with its contract with the 190 MW Ibom Power station, Accugas Limited supplies gas to fuel around ten per cent. of Nigeria's power generation capacity. The key terms of Accugas Limited's GSAs are summarised below.

The Uquo CPF consists of two identical gas processing trains, each designed to process up to 100 MMscfd. One train has been tested at levels up to 120 MMscfd, and it is the opinion of Seven that the CPF, with limited optimisation, could operate at up to 240 MMscfd on a continuous basis. As such, spare capacity of up to c.50 MMscfd is intended to be used as part of Accugas' business development plans going forward. There also exists significant spare capacity in Accugas Limited's pipeline network.

Savannah has conducted a review of the value of Accugas Limited, which has been assessed as reasonable by LR and incorporated in the Nigeria CPR. The base case NPV10 for Savannah's 20 per cent. interest in the Accugas Midstream Business has been assessed at US$209 million, which when adjusted for Savannah's pro rata share of approximately US$470 million debt which sits at Accugas Limited represents a base case value of US$115 million.

Gas Sales Agreements

There are currently three existing long-term GSAs in place, all of which are 80 per cent. take-or-pay arrangements and currently taking deliveries.

Figure 33, Accugas Summary of Key Gas Sales Agreements

	Calabar NIPP	*Unicem*	*Ibom Power*
Description	Nigerian State Power Plant	Lafarge Cement Plant	Nigerian State Power Plant
Term (Remaining)	20 Years (20)	20 years (14)	10 years (6)
Start Date	September 2017	January 2012	January 2014
Daily Contract Quantity (“DCQ”)	131 MMscfd	38.7 MMscfd	19.7 MMscfd
Take-or-Pay	80 per cent.	80 per cent.	80 per cent.
Gas Price	US$3.29/Mscf for the first year (price escalation applies)	US$5.00/Mscf	US$2.15/Mscf (price escalation applies)

Note: DCQ and Gas price defined in calorific value in some GSAs, have been converted to volume in this table.

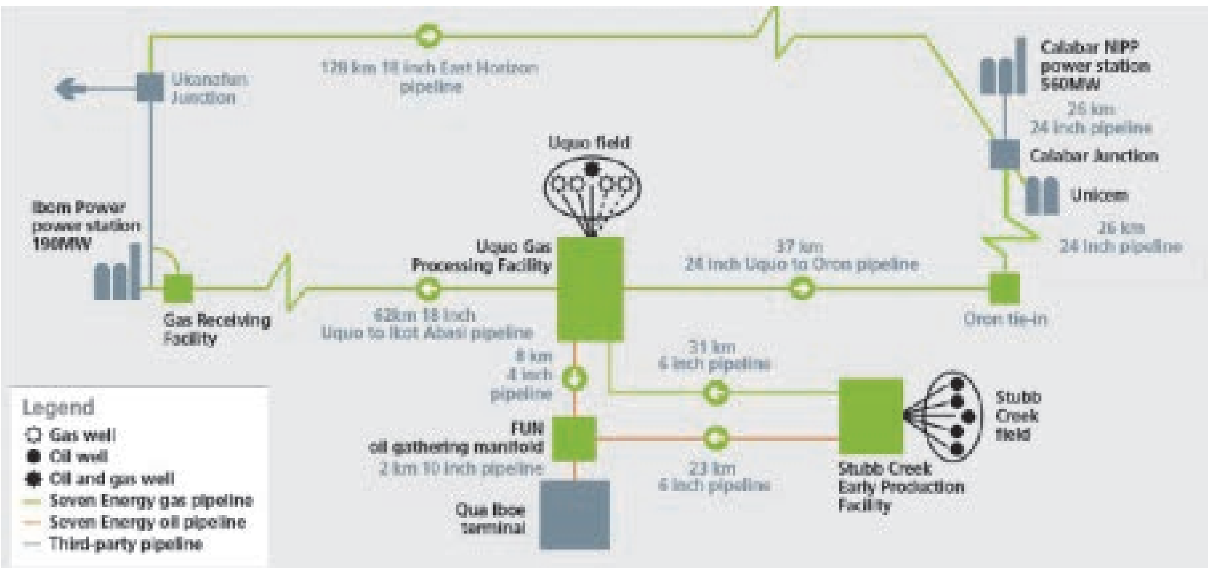
Accugas Limited’s historic focus has primarily been on high volume, but lower price power station customers, which sell their electricity into the regulated Nigerian distribution network. These customers underpinned the contracted forward gas sales which were required to justify the initial capital investment into the Accguas’ business infrastructure. Going forward, Accugas Limited’s business development opportunities are expected to be focused around the tie-in of high-value industrial customers. These “last-mile” customers are typically reliant on diesel fuel solutions, creating a significant pricing arbitrage for Accugas Limited to exploit. Accugas Limited’s facilities tie into three principal industrial activity hubs (areas surrounding Calabar, Port Harcourt and Aba).

Three non-binding heads of terms have been signed by Accugas Limited with potential new industrial customers in the Calabar area for gas sales of circa 5 MMscfd at an average price of US$7.5/Mcf.

Infrastructure

Recent developments at Accugas Limited’s facilities include the completion of the Uquo to Creek Town pipeline in November 2016 which facilitates the export of gas to Calabar NIPP and Unicem cement plant.[58]

Figure 34, Accugas Midstream Infrastructure



Source: Seven Energy, LR Nigerian CPR

[58] Seven Energy, 22 November 2016, Quarterly Report

Uquo Gas Processing Facility

The Uquo CPF processes gas from the Uquo Field, and a network of pipelines links the processing facility to existing customers. Commercial production from the Uquo Field commenced in 2014.

In addition to processing non-associated gas from the Uquo Field and future non-associated gas from the Stubb Creek Field, the Uquo CPF has the potential to provide a processing outlet for associated gas from other nearby Marginal fields; Qua Iboe (operated by Network Exploration and Production Nigeria Limited) and the Stubb Creek Field (operated by Universal). The associated gas from these fields can be delivered to the Uquo CPF by gas pipelines and eliminate gas flaring from crude oil operations and allow for oil production ramp-up.

Accugas Pipeline Network

The key gas pipelines in the Accugas Limited network include:

- Uquo to Ikot Abasi (62 km, 18-inch) – connects Uquo to the Ibom power station, constructed in 2010 – 2011
- Uquo to Oron (37 km, 24-inch) – connects Uquo to Oron, constructed in 2013-2014
- Oron to Creek Town (26 km, 24-inch) – connects Oron to the Calabar junction, construction completed in 2016
- East Horizon gas pipeline (128 km, 18-inch) – acquired in Q1 2014, delivering gas since 2012.

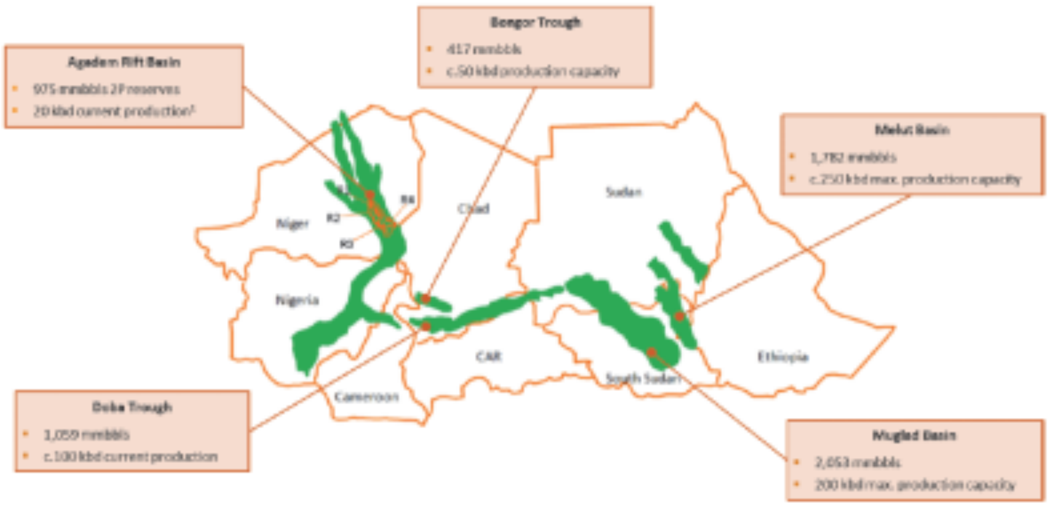
Accugas also owns the 8 km, 4-inches Uquo to Qua Iboe oil pipeline, which links the Uquo gas processing facility to the FUN Manifold (constructed in 2010-2011).

PART 8

NIGERIEN ASSET OVERVIEW

The Company's Nigerien assets, the R1/R2 and R3/R4 PSC Areas, are two large, onshore PSCs covering 8,406km^2 and 5,260km^2 respectively. The PSC Areas are located in the highly prospective Agadem Rift Basin in South East Niger. The ARB is comparable in scale to the North Sea rift system, and forms part of the Central African Rift System. The Central African Rift System consists of a series of highly oil prolific Cretaceous and Tertiary rifts throughout Niger, Chad, Sudan, South Sudan and also Nigeria, with over 6bn bbls of oil discovered to date. Topography in the ARB is relatively flat, with no significant mobile sand dunes. The PSC Areas are located c.200 km away from the nearest major population centres.

Central African Rift System – Regional Discoveries

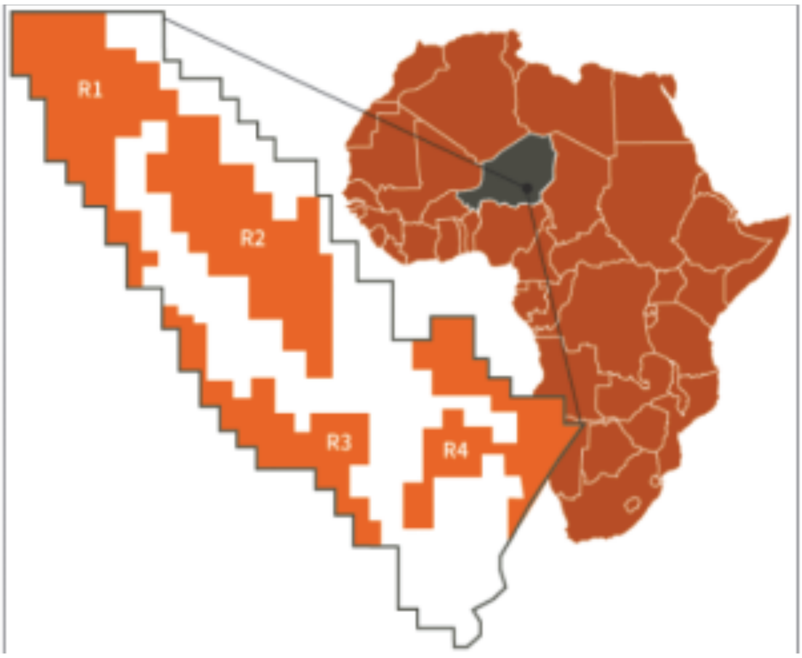


Source: Savannah

The PSC Areas represent c.50 per cent. of the ARB, and of the original Agadem PSC Area which was compulsorily relinquished by the CNPC in July 2013 and subsequently acquired by Savannah over the course of 2014 and 2015.

CNPC's involvement in Agadem has been transformational for the upstream industry in Niger, markedly increasing the success rate in the area, with 97 discoveries from 127 exploration wells, establishing 2P reserves of c.1bn bbls through the application of 3D seismic technology coupled with an efficient and effective operating model. Following the construction of a 20kbd refinery at Zinder and a 463km pipeline linking the refinery to Agadem, first oil from Agadem was established in 2011, only three years after license acquisition.

Location of the Company's Niger Assets



Source: Savannah

R1/R2 Production Sharing Contract

The R1/R2 PSC Area covers an area of approximately 8,406km^2. The R1/R2 PSC Area was formerly part of the original Agadem permit operated by CNPC, 50 per cent. of which CNPC mandatorily relinquished in June 2013 in accordance with the terms of the CNPC PSC.

On 3 July 2014, Savannah Niger entered into the R1/R2 PSC with the State of Niger to acquire a 100 per cent. working interest, pursuant to which the R1/R2 Signature Bonus was paid to the State of Niger.

R3/R4 Production Sharing Contract

On 31 July 2015, Savannah announced that Savannah Niger had signed the R3/R4 PSC, pursuant to which the R3/R4 Signature Bonus was paid to the State of Niger. The R3/R4 PSC Area was also formerly part of the original Agadem permit operated by CNPC and comprises a 5,249km^2 area in close proximity to the Company's R1/R2 PSC Area.

Operational Achievements

The Company acquired a basin-wide, airborne Full Tensor Gradiometry (FTG) survey in 2015-2015. 36,949km of data was acquired, on time and on budget, and was incorporated into Savannah's subsurface model.

In September 2016, the Company commenced a 3D seismic survey over an area of approximately 806km^2 of part of the R3 portion of the R3/R4 PSC Area ("**R3 East**"). The seismic survey was completed in January 2017, approximately US$1.2 million under budget and in 90 recording days, 25 days fewer than planned.

The Company's subsurface work on the R3 East 3D area confirmed the existence of multiple fault blocks, which have similar configurations to the Agadem Rift Basin's existing producing fields and to some of the Agadem Rift Basin's largest discoveries. As such, the focus of Savannah's initial upcoming drilling campaign in Niger will be the R3 East area, as announced on 11 April 2017.

Final pre-stacked time migrated dataset for the R3 East 3D seismic survey was received in July 2017, with excellent data quality and meeting key objectives of enhancing seismic imaging of the Eocene Upper Sokor and Alternances plays, and providing better definition of deeper prospective Cretaceous structures.

Drilling Programme and 3D Seismic Acquisition Plans

Savannah is planning to pursue its previously announced operational campaign in Niger, and plans to drill three wells in this initial campaign, focused on the R3 East 3D seismic area. The Company has signed a drilling contract with Great Wall Drilling Company Niger SARL, who have extensive experience of drilling and operating in the ARB. Drilling is expected to commence following the issue of the Second Tranche Placing Shares, using the GWDC 215 rig as previously announced. Wells are expected to cost US$6 – 8 million per well for this campaign.

Each well is expected to assess potential oil pay in the Eocene Sokor Alternances as a primary target, and in the Eocene-Oligocene Upper Sokor as a secondary target. CGG has prepared the Niger CPR that covers the Savannah PSCs. See Part 11 of this Admission Document for full details.

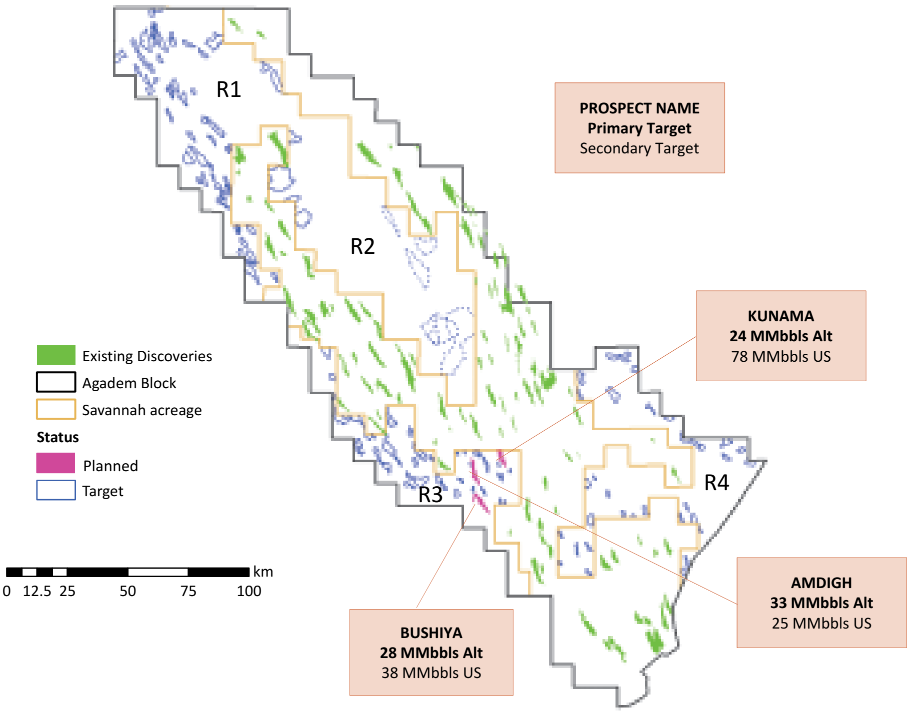
As part of this CPR, CGG has conducted a review of nine indicative Targets across the Savannah PSCs which have been high-graded for potential drilling. CGG has assessed these Targets to carry a low risk profile (i.e. similar to those drilled elsewhere in the basin to date).

Initial Drilling Campaign Planned Targets[1]

	PSC Area	Alternances Unrisked Mean Recoverable Resources, mmbbls	Upper Sokor Unrisked Mean Recoverable Resources, mmbbls	Total Unrisked Mean Recoverable Resources, mmbbls
Bushiya	R3	28	38	36
Amdigh	R3	33	25	39
Kunama	R3	24	78	35
Total		**85**	**141**	**110**

Source: Niger CPR, CGG

Prospect Location Map



Source: Savannah

[1] Volumes are CGG estimates of mean unrisked recoverable resources and assume a recovery factor of 30 per cent. Proposed well targets and order of drilling remain subject to change.

Rig and Drilling Contracts

The Company has signed a rig contract as well as other ancillary drilling service contracts (including cementing, drilling fluids, logging, etc.) with Great Wall Drilling Company Niger SARL, a subsidiary of the large Chinese integrated petroleum engineering service provider. GWDC currently operates in 33 countries worldwide with 439 rigs. GWDC has operated in Niger for over 11 years, and has drilled over 200 wells on Agadem (exploration, appraisal and development). GWDC has eight drilling rigs currently on Agadem, and four workover rigs used for completion and well testing.

The Enlarged Group has secured the use of the GW215 rig for its upcoming drilling campaign. The rig was constructed in 2007, and has drilled over 40 wells in the Agadem region to date.

Development Planning

Savannah has carried out conceptual studies for a 73mmbbl cluster development of four notional discoveries in the R3/R4 PSC Area, which have been reviewed by CGG and found to be reasonable. The R3 part of the R3/R4 PSC Area is where the Enlarged Group intends to carry out its initial exploration drilling campaign and the notional discoveries are intended to approximately replicate the drilling targets. The envisaged development concept includes a "hub and spoke" development model that has been used successfully elsewhere already in the basin. The concept consists of Field Processing Facilities tied back to a Central Field Processing Facility. A leased Early Production Facility is also proposed to enable a shorter schedule to first production.

CNPC currently sells domestically to the approximately 20kbopd capacity Nigerien Zinder refinery, via the 463 km Agadem-Zinder domestic pipeline. As the existing Zinder refinery is already fully supplied, incremental oil production will have to be exported. Three options for exporting production have therefore been developed by the Enlarged Group and reviewed by CGG.

Niger Oil Export Routes Map

Source: Savannah

Capital and field operating costs are estimated to be approximately \$6/bbl and \$8/bbl respectively. Descriptions of the three options and the estimated respective costs and tariffs are tabulated below.

Niger Oil Development Concept – Cost Assumptions

	Max Oil rate	Total Wells Drilled	Total Capex	Field Opex	Export tariff
	bopd	*#*	*US$ millions*	*US$ millions*	*$/bbl*
1. New third party 800km pipeline to connect with existing Chad-Cameroon pipeline	18,000	43	411	595	16
2. New third party 800km pipeline to Kaduna refinery, northern Nigeria	18,000	43	411	595	5
3. Existing 463km pipeline to Zinder refinery, and then trucking to Kaduna refinery, northern Nigeria	10,000	43	427	561	6

Source: Niger CPR, CGG

Results of the economic analysis are presented in the table below for the three options based on a $60/bbl Brent oil price escalating at 2 per cent. per year.

Summary of Niger Development Concept Economics

	Development Concept		
	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
NPV0 ($MM)	801	1132	1093
NPV10 ($MM)	**252**	**386**	**269**
IRR (%)	*32.2%*	*44.0%*	*26.1%*
NPV/bbl ($)	3.6	5.5	4.1

Source: Niger CPR, CGG

If the exploration drilling is successful, first production could be achieved in late 2020. This would be a fast-track program that relies on the completion of export pipelines by others in two of the options being considered. The option of trucking can this risk, and also offers a temporary early production solution for the pipeline options.

PART 9A

ACCOUNTANTS REPORT AND HISTORICAL FINANCIAL INFORMATION OF THE SEVEN GROUP

The Directors
Savannah Petroleum Plc
40 Bank Street
London E14 5NR

22 December 2017

Dear Directors

Seven Energy International Ltd

We report on the financial information set out on pages 119-179 for the three years and six months ended 30 June 2017 in respect of the consolidated financial information for Seven Energy International Ltd (the 'Seven Group'). This financial information has been prepared for inclusion in the AIM Admission Document dated 22 December 2017 of Savannah Petroleum Plc on the basis of the accounting policies set out in note 2. This report is required by Paragraph (a) of Schedule Two of the AIM Rules for Companies and is given for the purpose of complying with that paragraph and for no other purpose. We have not audited or reviewed the financial information for the six months ended 30 June 2016 which has been included for comparative purposes only, and accordingly do not express an opinion thereon.

Responsibilities

The Directors of Savannah Petroleum Plc are responsible for preparing the financial information on the basis of preparation set out in note 2 to the financial information and in accordance with International Financial Reporting Standards as adopted by the European Union.

It is our responsibility to form an opinion on the financial information and to report our opinion to you.

Save for any responsibility arising under Paragraph (a) of Schedule Two of the AIM Rules for Companies to any person as and to the extent there provided, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Paragraph (a) of Schedule Two of the AIM Rules for Companies, consenting to its inclusion in the AIM Admission Document.

Basis of opinion

We conducted our work in accordance with Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. Our work included an assessment of evidence relevant to the amounts and disclosures in the financial information. It also included an assessment of the significant estimates and judgments made by those responsible for the preparation of the financial information and whether the accounting policies are appropriate to the entity's circumstances, consistently applied and adequately disclosed.

We planned and performed our work so as to obtain all the information and explanations which we considered necessary in order to provide us with sufficient evidence to give reasonable assurance that the financial information is free from material misstatement whether caused by fraud or other irregularity or error.

Opinion on financial information

In our opinion, the financial information gives, for the purposes of the AIM Admission Document dated 22 December 2017, a true and fair view of the state of affairs of the Seven Group as at 31 December 2014, 31 December 2015, 31 December 2016 and 30 June 2017 and of its consolidated losses, consolidated cash flows and consolidated recognised gains and losses and changes in equity for the years ended 31 December 2014, 31 December 2015 and 31 December 2016 and the six months ended 30 June 2017 in accordance with the basis of preparation set out in note 2 and in accordance with IFRS as adopted by the European Union as described in note 2.

Material uncertainty related to going concern

We draw attention to note 2 to the Financial Information which indicates that the Seven Group's ability to continue as a going concern is dependent on the sufficiency of funding available to Seven prior to the completion of the transaction, within the period to at least twelve months from the date of approval of the Financial Information. This assessment includes the continued availability of Seven's existing debt facilities during that period up to completion along with the successful completion of the transaction. These events and conditions, along with the other matters explained in note 2, constitute a material uncertainty that may cast significant doubt on the Seven Group's ability to continue as a going concern. Our opinion is not modified in respect of this matter.

Declaration

For the purposes of Paragraph (a) of Schedule Two of the AIM Rules we are responsible for this report as part of the AIM admission document and declare that we have taken all reasonable care to ensure that the information contained in this report is, to the best of our knowledge, in accordance with the facts and contains no omission likely to affect its import. This declaration is included in the AIM admission document in compliance with Schedule Two of the AIM Rules.

Yours faithfully

KPMG LLP

15 Canada Square
London
E14 5GL

Consolidated Statement of Comprehensive Income

	Notes	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Revenue	5	378,155	353,571	101,920	66,538	61,750
Change in underlift	19	190,620	(61,985)	69,797	28,765	(97,182)
Production expenses	6	(231,736)	(190,400	(34,557)	(22,121)	(14,374)
Depletion	17	(120,273)	(88,956)	(45,603)	(34,646)	(16,096)
Gross profit/(loss)		216,766	12,230	91,557	38,536	(65,902)
Depreciation and amortisation	17	(3,000)	(3,320)	(1,758)	(1,184)	(639)
Impairment charge	17	(546,239)	(90,381)	(299,090)	–	(221,692)
Restructuring expenses	10	–	–	(6,942)	(6,943)	(3,057)
Other operating income/ (expenses)	8	(4,925)	(3,295)	3,507	7,023	4,312
Administrative expenses	9	(58,731)	(35,253	(25,763)	(13,228)	(8,690)
Operating profit/(loss)		(396,129)	(120,019)	(238,489)	24,204	(295,668)
Investment revenue	5	83	536	505	326	16
Finance costs	13	(76,181)	(103,420)	(107,611)	(51,786)	(59,628)
Foreign exchange gains – realised	11	429	1,974	9,274	11,363	(2,269)
Foreign exchange gains – unrealised	11	7,392	4,951	33,620	28,356	3,199
Profit/(Loss) before tax		(464,406)	(215,978)	(302,701)	12,463	(354,350)
Tax (expense)/credit	14	179,008	65,851	95,528	(3,988)	28,354
Profit/(Loss) after tax		(285,398)	(150,127)	(207,173)	8,475	(325,996)
Attributable to:						
Owners of the company		(261,609)	(149,033)	(240,017)	8,399	(325,097)
Non-controlling interests	34	(23,789)	(1,094)	32,844	76	(899)
Other comprehensive income/ (expense) for the period						
Profit/(Loss) for the year		(285,398)	(150,127)	(207,173)	8,475	(325,996)
Total other comprehensive income for the period		–	–	–	–	–
Total comprehensive income/ (expense) for the period		(285,398)	(150,127)	(207,173)	8,475	(325,996)
Attributable to:						
Owners of the Company		(261,609)	(149,033)	(240,017)	8,399	(325,097)
Non-controlling interests	34	(23,789)	(1,094)	32,844	76	(899)
Profit/(Loss) per share ($ per share)						
Basic from continuing operations	15	(74.43)	(37.72)	(54.50)	1.94	(72.76)
Diluted from continuing operations	15	(74.32)	(37.72)	(54.50)	1.79	(72.76)

Consolidated Statement of Financial Position

	Notes	*Year ended 31 December 2014 $000*	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Non-current assets					
Interest in joint arrangements	36	11,528	11,528	–	–
Intangible assets	16	73,896	104,714	–	–
Tangible assets and PPE	17	1,319,469	1,206,242	1,010,181	782,726
Other receivables	19	8,267	8,641	3,443	3,343
Deferred tax assets	23	200,111	233,206	254,843	260,294
		1,613,271	1,564,331	1,268,467	1,046,363
Current assets					
Inventories	20	291,396	228,988	295,324	197,410
Trade and other receivables	19	46,273	119,015	71,522	85,488
Cash and cash equivalents	21	38,454	30,473	12,804	14,150
		376,123	378,476	379,650	297,048
Total assets		1,989,394	1,942,807	1,648,117	1,343,411
Current liabilities					
Trade and other payables	22	(603,699)	(585,055)	(508,181)	(543,222)
Borrowings	24	(112,510)	(424,653)	(400,829)	(838,850)
Deferred revenue	29	(12,204)	–	–	(7,636)
Current tax liabilities	14	(727)	(720)	(785)	(784)
		(729,140)	(1,010,428)	(909,795)	(1,390,492)
Non-current liabilities					
Borrowings	24	(653,582)	(420,818)	(435,152)	–
Deferred tax liabilities	23	(124,916)	(103,580)	(29,625)	(6,721)
Provisions	26	(49,759)	(50,945)	(42,532)	(46,097)
Deferred revenue	29	(34,605)	(79,315)	(62,179)	(56,396)
		(862,862	(654,660)	(569,488)	(109,214)
Total liabilities		(1,592,002)	(1,665,088)	(1,479,283)	(1,499,706)
Net Assets/(liabilities)		397,392	277,719	168,834	(156,295)
Equity					
Share capital	30	5	5	5	5
Share premium		95,710	96,111	96,111	96,111
Irredeemable convertible loan notes ("ICLNs")	31	895,442	920,909	1,019,562	1,019,562
Retained reserves	32	(592,082)	(736,529)	(976,911)	(1,301,141)
Equity attributable to owners of the Company		399,075	280,496	138,767	(185,463)
Non-controlling interests	34	(1,683)	(2,777)	30,067	29,168
Total equity		397,392	277,719	168,834	(156,295)

Consolidated Statement of Changes in Equity

	Share Capital $000	Share Premium $000	Irredeemable Convertible Loan Notes ('ICLNs') $000	Retained Deficit $000	Equity Reserves $000	Total $000	Non-Controlling Interests $000	Total Equity $000
At 1 January 2014	5	95,310	612,583	(373,607)	39,384	373,675	22,106	395,781
Credit to equity for share based payments	–	–	–	–	4,150	4,150	–	4,150
Warrants expiry	–	–	–	1,396	(1,396)	–	–	–
Issuance of shares	–	400	–	–	(400)	–	–	–
Issuance of ICLNs	–	–	288,000	–	–	288,000	–	288,000
Expenses on issuance of ICLNs	–	–	(5,141)	–	–	(5,141)	–	(5,141)
Total comprehensive income/(expense) for the period	–	–	–	(261,609)	–	(261,609)	(23,789)	(285,398)
At 31 December 2014	5	95,710	895,442	(633,820)	41,738	399,075	(1,683)	397,392
Credit to equity for share based payments	–	–	–	–	4,987	4,987	–	4,987
Issuance of shares	–	401	–	–	(401)	–	–	–
Issuance of ICLNs	–	–	25,650	–	–	25,650	–	25,650
Expenses on issuance of ICLNs	–	–	(183)	–	–	(183)	–	(183)
Total comprehensive income/(expense) for the period	–	–	–	(149,033)	–	(149,033)	(1,094)	(150,127)
At 31 December 2015	5	96,111	920,909	(782,853)	46,324	280,496	(2,777)	277,719
Credit to equity for share based payments	–	–	–	–	145	145	–	145
Treasury Shares	–	–	–	–	(2,324)	(2,324)	–	(2,324)
Issuance of ICLNs	–	–	100,000	–	–	100,000	–	100,000
Expenses on issuance of ICLNs	–	–	(1,342)	–	–	(1,342)	–	(1,342)
Total comprehensive income/(expense) for the period	–	–	–	8,399	–	8,399	76	8,475
At 30 June 2016 (unaudited)	5	96,111	1,019,567	(774,454)	44,145	385,374	(2,701)	382,673
Credit to equity for share based payments	–	–	–	–	1,813	1,813	–	1,813
Treasury Shares	–	–	–	–1	1	–	–	1
Issuance of ICLNs	–	–	(5)	–	–	(5)	–	(5)
Total comprehensive income/(expense) for the period	–	–	–	(248,416)	–	(248,416)	32,768	(215,648)
At 31 December 2016	5	96,111	1,019,562	(1,022,870)	45,959	138,767	30,067	168,834
Credit to equity for share based payments	–	–	–	–	867	867	–	867
Total comprehensive income/(expense) for the period	–	–	–	(325,097)	–	(325,097)	(899)	(325,996)
At 30 June 2017	5	96,111	1,019,562	(1,347,967)	46,826	(185,463)	29,168	(156,295)

Consolidated Statement of Cash Flows

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*(Unaudited) six months ended 30 June 2016 $000*	*Six months ended 30 June 2017 $000*
Operating activities					
(Loss)/profit for the period	(285,398)	(150,127)	(207,173)	8,475	(325,996)
Adjustments for:					
Investment revenue	(83)	(536)	(505)	(326)	(15)
Finance costs	76,181	103,420	107,611	51,786	59,628
Impairment charge	546,239	90,381	299,090	–	221,692
Depreciation and amortisation	3,000	3,320	1,758	1,184	639
Depletion	120,273	88,956	45,603	34,646	16,096
Loss on disposal of property, plant and equipment	53	53	95	24	31
Tax credit	(179,008)	(65,851)	(95,528)	3,988	(28,354)
Share-based payment expense	4,150	–	4,969	145	867
Provision for doubtful debts and inventory	–	4,987	1,958	–	–
Unrealised foreign exchange gains	(7,821)	(4,945)	(33,620)	(28,356)	(3,199)
Operating cash flow before movements in working capital	277,586	69,658	124,258	71,566	(58,611)
Decrease/(increase) in inventories	(192,226)	62,443	(66,336)	(28,763)	97,914
Decrease/(increase) in trade and other receivables	5,908	(20,728)	47,493	18,628	(13,966)
Increase/(decrease) in trade and other payables	66,504	116,534	(24,112)	(19,838)	(3,987)
Increase/(decrease) in deferred revenue	(16,700)	(13,099)	(24,064)	(544)	1,853
Net cash provided by operating activities	141,072	214,808	57,239	41,049	23,203
Investing activities					
Interest received	83	40	156	82	9
Proceeds from disposal of property, plant and equipment	89	43	248	–	–
Proceeds from disposal of oil and gas asset (note 18)	7,000	–	–	–	–
Purchases of property, plant and equipment and intangible assets	(334,734)	(198,672)	(77,917)	(71,582)	(3,609)
Acquisitions of subsidiaries, net of cash acquired	(151,205)	(444)	–	–	–
Net cash used in investing activities	(478,767)	(199,033)	(77,513)	(71,500)	(3,600)
Financing activities					
Interest and financing fees paid	(105,937)	(116,531)	(88,459)	(49,803)	(15,452)
Net financing deposits received	3,880	838	3,760	(29)	101
Repayments of borrowings	(483,213)	(43,995)	(32,474)	(14,012)	(2,278)
Proceeds from borrowings	657,343	136,879	23,300	–	–
Proceeds from issue of ICLNs	255,000	–	100,000	100,000	–
Net cash provided/(used) by financing activities	327,073	(22,809)	6,127	36,156	(17,629)
Net increase/(decrease) in cash and cash equivalents	(10,622)	(7,034)	(14,147)	5,705	1,974
Cash and cash equivalents at beginning of period	50,383	38,454	30,473	30,473	12,804
Effect of foreign exchange rate changes	(1,307)	(947)	(3,522)	(2,814)	(628)
Cash and cash equivalents at end of period	38,454	30,473	12,804	33,364	14,150

NOTES TO THE HISTORICAL FINANCIAL INFORMATION

1. General information

The historical financial information ("HFI") has is being prepared in compliance with Paragraph (a) of Schedule Two of the AIM Rules for Companies.

Savannah Petroleum Plc ("Savannah") is acquiring certain Nigerian oil and gas assets of Seven Energy International Limited (the "Agreed Transaction").

The Agreed Transaction involves the acquisition by Savannah of the following interests from Seven, Seven Energy Finance Limited and certain other subsidiaries of Seven (together the "Seven Group"):

- 40 per cent. participating interest in the Uquo oil & gas field;
- 62.5 per cent. interest in Universal Energy Resources Limited ("UERL"), which holds a 51 per cent. participating interest in the Stubb Creek oil & gas field; and
- A 20 per cent. interest in the Accugas Limited ("Accugas") midstream business, a c.260km gas pipeline network and associated gas processing infrastructure.

The historical financial information ("HFI") is presented in US Dollars, which is the functional currency of both Savannah and Seven. All values are rounded to the nearest thousand, except where otherwise indicated. Foreign operations are included in accordance with the policies set out in note 2.

The HFI presented below has been prepared by the Directors of Savannah and shows the consolidated financial statements of the Seven Group for the 12 month periods ended 31 December 2014, 31 December 2015, 31 December 2016 and the six month period ended 30 June 2017 ("review period"), as adjusted by Savannah for the purposes of presenting such information in accordance with Savannah's own accounting policies and to reflect the latest certified reserves information. The consolidated Seven Group financial information includes interests not being acquired as part of the Agreed Transaction, notably those relating to Seven's Strategic Alliance Agreement ("SAA") with the Nigerian Petroleum Development Company ("NPDC") and the Anambra basin; the information also reflects Seven's 100 per cent. interest in Accugas.

2. Significant accounting policies

Basis of accounting

The Financial Statements have been prepared on the historical cost basis, except for the revaluation of certain financial instruments and share-based payments. Historical cost is generally based on the fair value of the consideration given in exchange for the assets at the time of initial recognition. The principal accounting policies adopted are set out below.

The consolidated financial information does not constitute statutory accounts for the review period.

For the years ended 31 December 2014 and 31 December 2015, the Seven Group audit report included an emphasis of matter relating to the significant uncertainty regarding the company's ability to continue as a going concern. At the date of approval of the HFI, no audit report had been issued for the Seven Group for the year ended 31 December 2016 nor for the six months ended 30 June 2017.

Accounting policies adopted in these Financial Statements are based on those of Savannah. These accounting policies henceforth represent those of Savannah and the Seven Group combined (the "Enlarged Group").

Statement of compliance

The consolidated financial information has been prepared in accordance with the requirements of the Prospectus Directive and the Listings Rules, and has been prepared in accordance with IFRSs adopted for use in the EU ("Adopted IFRSs").

Going concern

The Transaction

On 14 November 2017 Seven Energy International Limited and certain of its subsidiary undertakings ('Seven Group') entered into an agreement with Savannah Petroleum PLC ('Savannah') and certain of the Seven Group's financial creditors (the 'Lock Up Agreement'). Under the terms of the Lock Up Agreement, the Seven Group has conditionally agreed:

i. to dispose of, or granted the option to dispose of, specified assets of the Seven Group to Savannah by way of the sale of shares in the principal subsidiary undertakings and any rights under the disputed Strategic Alliance Agreement ('SAA') with Nigerian Petroleum Development Corporation (see note 4 to the Historical Financial Statements) (the 'Transaction'); and

ii. terms for the redemption of certain of the Seven Group's borrowings and the restructuring of other borrowings on revised terms amounting to US$473.9 million in aggregate (the 'Amended Debt') which will be repaid or assigned under the terms of the Transaction.

Whilst Savannah has raised up to US$125 million through the issue of shares to new and existing investors on 22 December 2017 for the purposes of funding the Transaction and Amended Debt set out in the Lock Up Agreement the Lock Up Agreement is conditional on Savannah obtaining government and regulatory consents to the change in control of the relevant oil and gas interests and pipeline licenses of the Seven Group that are the subject of the Transaction and to the satisfactory execution of certain terms set out in a signed agreement between (1) Savannah and (2) the African Infrastructure Investment Fund 3 ("AIIM") AIIM, together with one or more potential co-investors, being the 'Investor' (the "**Investment Agreement**"). The Investment Agreement will be executed before posting of the Admission Document with the agreed form Accugas Shareholder Agreement appended to it. Savannah will acquire 20 per cent. and the Investors 80 per cent. in Accugas on Completion of the Transaction with the Seven group. The Investors will inject US$45 million of new money in the form of working capital into Accugas. The Company is currently in discussions with Frontier in relation to the execution of certain new agreements in order to formalise the arrangements between: (i) Frontier and SUGL in relation to the Uquo JOA; (ii) Frontier and Accugas in relation to the Uquo CPF; and (iii) the Uquo JV and Accugas in relation to the sale of gas to Accugas Limited. The Company will not enter into the Implementation Agreement and proceed with the Transaction unless and until the Frontier Agreements in a form satisfactory to it have been agreed and executed.

The SSN element of the Transaction may be implemented by way of Court sanctioned Schemes of Arrangement in various jurisdictions, following which an Administrator will be appointed to conclude the affairs of the Seven Group and, ultimately, to wind the Company up. On the basis of the planned liquidation, the Seven Group as a whole would not meet the definition of a going concern. The audited Seven Group financial statements for the years ended 31 December 2014 and 2015 were prepared on a going concern basis and the Auditors Reports thereon contained an Emphasis of Matter with respect to the going concern assumption but were not qualified in this respect. Seven Group financial statements have not yet been approved for the year ended 31 December 2016 or for the period to 30 June 2017. Whether the financial statements of the Seven Group would be prepared by the directors of Seven on a going concern basis or on a non-going concern basis does not affect the amounts of assets, liabilities income or expense reported in this Historical Financial Information prepared by the Directors of Savanah.

However, in accordance with SIR 2000 and EU-IFRSs, the disclosures below explain the uncertainties that exist in respect of the equity fund raising, the successful completion of the proposed transaction and, ultimately, the continuation as a going concern of those parts of the Seven Group that Savanah proposes to acquire.

The assets and operations that Savannah intend to acquire will remain under the control of the Seven group until completion of the transaction, the timing of which is uncertain. During that period Seven will continue to be reliant on the continued availability of its existing funding to continue to meet its liabilities as they fall due. As explained below, the terms of the transaction provide for Savannah to provide additional funding to Seven (the "Liquidity facility") during the period between the equity fundraising and completion of the transfer of the relevant assets and liabilities. It is expected that Seven will require the 1st and 2nd tranche to meet certain obligations related to advisor fees and Savannah is prepared to waive one of the conditions precedent (CP) to allow them to do so. The CPs in relation to the 3rd tranche remains unchanged.

These Consolidated Historical Financial Statements consolidate the individual financial statements of all Seven Group entities that are controlled by the Seven group including the Seven Group's principal operating subsidiaries which are part of the Transaction including Seven Uquo Gas Limited, Accugas Limited, East Horizon Gas Company Limited, Universal Energy Resources Limited and Seven Exploration & Production Limited.

Seven Group's operational and funding position

The Company entered a period of financial distress in 2016, which left it unable to service its debt and ongoing funding obligations as they fell due, and is therefore in default under the terms of each of these borrowing facilities and the Seven Group has not received any waivers of these defaults.

These borrowings are, therefore, currently repayable on demand and have been categorized as falling due in less than one year as at 30 June 2017. While the Transaction envisages amendment to the terms of certain Debt (see note 24), these amended terms are conditional on the Transaction being completed. Therefore, in the period prior to completion of the Transaction, the Seven Group will remain reliant on the continued availability of amounts borrowed under the existing facilities and in respect of which the Seven Group remains in default.

The Seven Group is also in the process of renegotiating certain other borrowings that are not subject to the Lock Up agreement, but will need to be renegotiated prior to completion of the Transaction. These other borrowings amount to US$416.7 million in aggregate, including US$412 million of borrowings by Accugas Limited. No agreement has yet been reached with the lenders and the Seven Group remains reliant on the continued availability of amounts borrowed under the existing facilities and in respect of which the Seven Group remains in default.

As at 30 June 2017, the Seven Group had borrowings of US$890.5 million[1] and cash and cash equivalents of US$17.5 million with access to these funds largely restricted by the lending banks. The Seven Group requires waivers from the banks in order to release funds from the accounts. The Seven Group has sought to secure funding from other parties, including existing shareholders but has been unsuccessful in its efforts and as a result is currently going through a restructuring process alongside having entered into the Lock Up Agreement with Savannah as noted above. The Seven Group has recently seen an increase in cash flows and expects those to be sufficient to cover some of the short term funding requirement.

Savannah's interests in the Seven Group on completion and the Amended Debt

The Agreed Transaction will involve the acquisition by Savannah of the following Seven Group interests:

- 40 per cent. participating interest in the Uquo oil & gas producing field;
- 62.5 per cent. interest in Universal Energy Resources Limited ("UERL"), which holds a 51 per cent. participating interest in the Stubb Creek oil & gas producing field; and
- 20 per cent. interest in the Accugas Limited ("Accugas") midstream business, which comprises c.260km gas pipeline network in Akwa Ibom and Cross River States and associated gas processing infrastructure in conjunction with a co-investors AIIM (and certain other potential co-investors) as set out in the Accugas Term Sheet

The Transaction consideration is expected to be:

- US$42.5 million in cash and US$109.5 million in new ordinary shares to the holders of the SSNs;
- US$3.5 million in cash and US$9.2 million in new ordinary shares to the lender of the second bilateral facility;
- Reinstatement of US$85 million of Seven's 10.50 per cent. Senior secured notes due 2021 issued at a Savannah subsidiary company level on a non-recourse basis to Savannah; and
- A US$20 million new capital contribution for the SSNs will be exchanged for a new US$26.7 million Savannah share issuance.

In relation to the SAA, NPDC served a notice of termination on 31 January 2017 alleging default by Seven Energy Production Limited ("SEPL"). SEPL has contested this allegation and continues to seek to agree a settlement with NPDC with a view to effecting a reinstatement of the SAA on the same or different terms.

[1] Includes $4.7 million loan from the Akwa Ibom Investment (a related party)

SEPL is not being acquired by Savannah as part of the Transaction. In line with its business and stated strategy, Savannah will take advantage of future commercial opportunities, which may include the SAA depending upon the outcome of the ongoing settlement discussions. In such circumstances, the assumption or acquisition of the SAA would be the subject of a separate transaction independent from the Transaction.

Seven Group ongoing operations

Between the date on which the Lock-Up Agreement is entered into and completion of the transaction, Savannah will exercise certain controls over the Group by virtue of the obligations imposed on the group under the Lock-Up Agreement as regards the management of its business and its support for the transaction. Upon signature of the Implementation Agreement these controls will become more fulsome, including greater support of the transaction, more prohibited actions on all parties and a more complete outline of the transaction.

Implementation of the Agreed Transaction is expected to take around 4-5 months from the point of entering into the Lock-Up Agreement, allowing for, *inter alia*:

- completion by Savannah of a successful equity marketing process to raise the cash to effect the Agreed Transaction;
- signing of the Implementation Agreement with all relevant stakeholders;
- sanction of the Schemes or the Exchange Offer; and
- receipts of governmental and regulatory consents.

We expect that Seven Group's obligations in the Implementation Agreement will include taking reasonable steps to preserve and protect the value of the Group's business and assets as well as actively assisting with the implementation and consummation of the transaction.

Funding Position

In the interim period between Lock-Up and the Transaction completing, Savannah has also agreed to provide to the Seven Group a super senior secured revolving credit facility (the "Liquidity Facility") of up to US$20 million to be made available in three tranches as follows:

- firstly, US$1.5 million (1st tranche) which has been pre-funded to a client account of legal counsel to the Seven Group (and is held subject to an undertaking provided by such legal counsel) and which shall be transferred to an account of Seven upon signing of the Liquidity Facility and the satisfaction of all conditions precedent thereunder and which is only permitted to be withdrawn to finance projected costs in connection with any insolvency, liquidation or administration proceedings and working capital requirements involving any member of the Seven Group;
- secondly, US$3.5 million (2nd tranche) available from signing of the Lock-Up Agreement, subject to all conditions precedent to the Liquidity Facility having been satisfied although Savannah is willing to waive (through the addendum to the Lock-up agreement) one of the conditions precedent to allow the Seven Group to have access to these funds; and
- thirdly, the remaining US$15 million (3rd tranche) available from signing of the Implementation Agreement (subject to all conditions precedent to the Liquidity Facility having been satisfied).

Any drawings under the Liquidity Facility (other than the US$1.5 million that has to be pre-funded) are subject to approval by Savannah of the payments to be made from such drawings unless such payments are pre-agreed. Loans under the Liquidity Facility are subject to PIK interest at 6 per cent. p.a. and are repayable in full upon completion of the Agreed Transaction or, if earlier, on termination of either the Lock-up Agreement or the Implementation Agreement.

It is intended that the Liquidity Facility will be used to part fund the advisory and legal fees incurred by the Seven Group as part of the Agreed Transaction. Savannah intends to fund the first and second tranches of the Liquidity Facility from existing cash resources, its revolving loan facility with Oragroup SA and Loan Notes issued by the Company. The third tranche will be financed from the proceeds of the proposed equity fundraise.

Going Concern basis of preparation

The Savannah Directors, have considered the Seven Group current operations, funding position and forecast Transaction completion timescale for the period of at least twelve months from the date of approval of the Historical Financial Information, prepared for the purpose of the re-admission of the Savannah shares and the proposed Transaction.

The forecast indicates that the Seven Group will not generate adequate cash to meet its obligations for the foreseeable future therefore the timing of the completion of the transaction is relevant to an assessment of the funds needed by the Seven Group in the forecast period and should Completion be delayed beyond 31 March 2018 then the Seven Group may have to secure additional funding to meet its obligations as they fall due and address its current debt position with its banks.

The Seven Group cashflow projections and operational forecasts assume that the amounts currently made available under the existing debt facilities remain available, together with the additional funding from Savannah; and assume that the outstanding conditions as set out above are concluded and the Transaction completes by the end of April 2018.

Whilst the Savannah Board believe that it is reasonable to assume that the Transaction will complete in the timescale this may not be the case and there is uncertainty that the funding provided to the Seven group through the Liquidity Facility will be sufficient to meet the funding requirements of the Seven Group as set out in the Liquidity Facility agreement and that cash shortages will not arise requiring alternative spending plans to be required or that unforeseen operational matters or other Corporate related events may give rise to increased levels of funding requirement that cannot be met out of the Seven Group's existing working capital facilities. In addition, it is assumed that the current arrangements with Seven Group's debt providers, particularly where the Seven Group is in default, will be maintained or waived during the period up to Completion of the Transaction but this remains an area of uncertainty. The Savannah Board are not aware of any specific indications to suggest that these arrangements will not be maintained or waived.

It is noted that the Transaction may not complete or complete as planned given the various regulatory approvals that are required along with the additional agreements to be agreed. Should the Transaction not conclude, then the Seven Group will require alternative debt restructuring arrangements and will need to make alternative plans with regards to the planned winding up of the Seven Group. If the Transaction is not implemented, and in the absence of continued forbearance and liquidity support from the Seven Group's financial creditors, certain key Seven Group companies are likely to have to enter into insolvency processes.

The Savannah Directors, after making enquiries and considering the complexities of the proposed Transaction and the related uncertainties described above, consider that the above matters represent a material uncertainty that may cast significant doubt on Seven Group's ability to continue as a going concern and, therefore, to continue realising its assets and discharging its liabilities in the normal course of business in the period prior to the uncertain completion of the Transaction. These Historical Financial Statements do not include any adjustments that would result from the Going Concern basis of preparation being inappropriate.

Basis of consolidation

The consolidated Financial Statements incorporate the Financial Statements of the Seven Group, made up to 31 December 2014, 31 December 2015, 31 December 2016, as well as for the half year to 30 June 2017. An unaudited statement of comprehensive income and statement of cash flows have also been prepared for the half year ended 30 June 2016. Control is achieved where the Seven Group:

- has the power over the investee;
- is exposed, or has rights to variable returns from its involvement with the investee; and
- has the ability to use its power to affect its returns.

The results of subsidiaries acquired or disposed of during the year are included in the consolidated statement of comprehensive income from the date of obtaining control or up to the effective date of disposal, as appropriate. Where necessary, adjustments are made to the Financial Statements of subsidiaries to bring the accounting policies used in line with those used by the Enlarged Group. All intra-group transactions, balances, income and expenses are eliminated on consolidation.

Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Enlarged Group's equity therein. Non-controlling interests consist of the amount of those interests at the date of the original business combination (see below) and the non-controlling interest's share of changes in equity since the date of the combination.

Changes in the Enlarged Group's interests in subsidiaries that do not result in a loss of control are accounted for as equity transactions. The carrying amount of the Enlarged Group's interest and the non-controlling interests are adjusted to reflect the changes in their relative interests in the subsidiaries. Any difference between the amount by which the non-controlling interests are adjusted and the fair value of the consideration paid or received is recognised directly in equity and attributed to the owners of Seven.

Jointly controlled operations

A joint arrangement is an arrangement over which two or more parties have joint control. The Seven Group is engaged in oil and gas exploration, development, production and distribution through unincorporated joint ventures or jointly controlled entities. The Seven Group accounts for its share of assets, liabilities, revenues and expenses of unincorporated joint ventures as joint operations. The Seven Group accounts for its interests in jointly controlled entities using the equity method. Under the equity method, the investment is initially recognised at cost. The carrying amount of the investment is adjusted to recognise changes in the Seven Group's share of net assets of the venture since the acquisition date. The consolidated statement of comprehensive income reflects the Group's share of results of operations in the venture.

The Seven Group accounts for its interest in the SAA as jointly controlled operation. It therefore fully consolidates its 55 per cent. share of the operation. More detail on the SAA and its accounting treatment can be found in the SAA section under note 4 "Critical accounting judgements and key sources of estimation uncertainty". Other joint operations are detailed in note 36.

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The consideration transferred in a business combination is measured at fair value, which is calculated as the sum of the acquisition date fair values of assets transferred by the Enlarged Group, liabilities incurred by the Enlarged Group to the former owners of the acquiree, and the equity interest issued by the Enlarged Group in exchange for control of the acquiree. Acquisition-related costs are recognised in the statement of comprehensive income as incurred.

Where applicable, the consideration for the acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition where they qualify as measurement period adjustments. All other subsequent changes in the fair value of contingent consideration classified as an asset or liability are accounted for in accordance with relevant IFRSs.

Where a business combination is achieved in stages, the Enlarged Group's previously held interests in the acquired entity are re-measured to fair value at the acquisition date (i.e. the date the Enlarged Group obtains control) and the resulting gain or loss, if any, is recognised in the consolidated statement of comprehensive income. Amounts arising from interests in the acquiree prior to the acquisition date that have previously been recognised in other comprehensive income are reclassified to the consolidated statement of comprehensive income, where such treatment would be appropriate if that interest were disposed of.

The acquiree's identifiable assets, liabilities and contingent liabilities that meet the conditions for recognition under IFRS 3 (2008) are recognised at their fair value at the acquisition date, except that:

- deferred tax assets or liabilities and liabilities or assets related to employee benefit arrangements are recognised and measured in accordance with *IAS 12 Income Taxes and IAS 19 Employee Benefits* respectively;
- liabilities or equity instruments related to the replacement by the Enlarged Group of an acquiree's share-based payment awards are measured in accordance with *IFRS 2 Share-Based Payment*; and
- assets (or disposal groups) that are classified as held for sale in accordance with *IFRS 5 Non-current Assets Held for Sale and Discontinued Operations* are measured in accordance with that Standard.

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of non-controlling interest of the acquiree, and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the acquisition date amounts of the identifiable assets acquired and liabilities assumed.

If the initial accounting for a business combination is incomplete by the end of the reporting period in which the combination occurs, the Enlarged Group reports provisional amounts for the items for which the accounting is incomplete. Those provisional amounts are adjusted during the measurement period, or additional assets or liabilities are recognised, to reflect new information obtained about facts and circumstances that existed as of the acquisition date that, if known, would have affected the amounts recognised as of that date.

The measurement period is the period from the date of acquisition to the date the Enlarged Group obtains complete information about facts and circumstances that existed as of the acquisition date, and is subject to a maximum of one year.

Commercial reserves

The Enlarged Group defines commercial reserves as proven and probable oil and gas reserves, which are defined as the estimated quantities of crude oil, natural gas and natural gas liquids that geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and that are considered commercially producible. This is equivalent to the 2P classification established by the Society of Petroleum Engineers where there is a 50 per cent. statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proven and probable reserves and a 50 per cent. statistical probability that it will be less.

Intangible assets – oil and gas exploration and appraisal assets

The Enlarged Group adopts the "successful efforts" method of accounting for exploration and evaluation costs under IFRS 6, Exploration for and Evaluation of Mineral Resources. All licence acquisition, exploration and evaluation costs are capitalised within intangible exploration and appraisal assets in cost centres by well, field or exploration area, as appropriate. Pre-licence expenditures on oil and gas assets are recognised as an expense within the consolidated statement of comprehensive income when incurred.

If commercial reserves are established then the relevant cost is transferred (following an impairment review as described below) from intangible exploration and appraisal assets to upstream assets within property, plant and equipment. Expenditure incurred after the commerciality of the field has been established are capitalised within upstream assets pending evaluation of commercial reserves. If prospects are deemed to be impaired (unsuccessful) on completion of an evaluation, the associated capitalised costs are charged to the consolidated statement of comprehensive income.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation, depletion and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning obligation, if any, and, for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

With the exception of upstream oil and gas assets, depreciation is charged to the consolidated statement of comprehensive income on a straight-line basis:

	Annual rate
Furniture, fixtures and equipment	20 per cent.
Vehicles	20 per cent.
Computer hardware and software	10 per cent.
Leasehold improvements	33 per cent.

The Seven Group's infrastructure assets (pipelines, processing facility and gas receiving facility) are depreciated on a straight line basis over the useful economic lives of the material component assets being principally between 15-25 years. Depreciation is shown within Depletion in the consolidated statement of comprehensive income. The Seven Group reviews the useful economic lives and depreciation rates annually.

Oil and gas properties are depleted using a unit-of-production method, which is the ratio of oil and gas production in the period to the estimated quantities of commercial reserves at the end of the period plus production in the period, generally on a field-by-field basis. Costs used in the unit-of-production calculation take into account expenditures incurred to date, together with the future capital expenditure expected to be incurred to access the commercial reserves. Changes in the estimates of commercial reserves or future field development costs are accounted for prospectively.

Assets in the course of construction are not depreciated. Depreciation commences on assets in the course of construction when the assets are ready for their intended use.

The gain or loss arising on the disposal or retirement of an asset is determined as the difference between the sales proceeds and the carrying amount of the asset and is recognised in administrative expenses.

Impairment

The Enlarged Group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable, for example, low prices or margins for an extended period or, for oil and gas assets, significant downward revisions of estimated commercial reserves or increases in estimated future development expenditure. If any such indication of impairment exists, the Enlarged Group makes an estimate of the asset's recoverable amount. Where it is not possible to estimate an asset's recoverable amount, the Enlarged Group estimates the recoverable amount and assesses impairment of the cash generating unit ("CGU") to which the asset belongs. A CGU is the lowest level of a group of individual assets that are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets.

An asset or CGU's recoverable amount is the higher of its fair value less costs to sell and its value in use. Where the carrying amount of an asset or CGU exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using an appropriate discount rate that reflects current market assessments of the time value of money.

An assessment is made at each reporting date as to whether there is any indication that previously recognised impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years. Such reversal is recognised in the consolidated statement of comprehensive income.

Decommissioning provision

Provision for decommissioning is recognised when the Enlarged Group has a legal or constructive obligation to dismantle and remove a facility or an item of plant and to restore the site on which it is located, and where a reliable estimate can be made. A corresponding adjustment to property, plant and equipment of an amount equivalent to the provision is also recognised. This is subsequently depreciated as part of the asset and included in depletion expense in the statement of comprehensive income. Changes in the estimated timing of decommissioning or decommissioning cost estimates are accounted for prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The unwinding of the discount on the decommissioning provision is classified in the consolidated statement of comprehensive income as finance costs.

Inventories

Inventories of oil and gas assets (underlift) are stated initially at their net realisable values and any movements in net realisable values are recognised in the income statement.

Other inventories are stated at the lower of cost and net realisable value. Cost is determined by the first-in first-out method and comprises direct materials and, where applicable, direct labour, overheads and other charges incurred in bringing the inventories to their present location and condition. Net realisable value represents the estimated selling price less all estimated costs to be incurred in marketing, selling and distribution.

Revenue recognition

Revenue arising from the sale of oil and gas products is recognised when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for oil and gas products provided in the normal course of business, net of discounts, customs duties and sales taxes.

Liftings or offtake agreements associated with the sale of oil, natural gas, natural gas liquids, liquefied natural gas, petroleum and petrochemical products in which the Enlarged Group has an interest in jointly owned or controlled operations are such that each participant may not receive and sell its precise share of the overall production in each period. The resulting imbalance between cumulative entitlement and cumulative production (less inventory) attributable to each participant at a reporting date represents 'overlift' or 'underlift'. Overlift and underlift are initially valued at market value and recorded as current liabilities or current assets respectively. Underlift balances are recorded as Inventory as it relates to produced oils stock. Movements in overlift or underlift are adjusted during an accounting period such that gross profit is recognised on an entitlements basis. Revenue is recognised on an actual invoiced basis for the value of the liftings made in the period.

Interest income is accrued on a time basis, by reference to the principal outstanding and at the effective interest rate applicable, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial asset to that asset's net carrying amount.

Foreign currencies

The Enlarged Group's functional currency and presentation currency for the consolidated Financial Statements is the US Dollar.

At each balance sheet date, monetary assets and liabilities that are denominated in foreign currencies are retranslated at the rates prevailing on the balance sheet date. Non-monetary items carried at fair value that are denominated in foreign currencies are translated at the rates prevailing at the date when the fair value was determined. Non-monetary items that are measured in terms of historical cost in a foreign currency are not retranslated. Exchange differences upon re-measurement are recognised in the statement of comprehensive income in the period in which they arise.

For the purpose of presenting consolidated Financial Statements, the assets and liabilities of the Enlarged Group's foreign operations are translated at exchange rates prevailing on the balance sheet date. Income and expense items are translated at the exchange rates at the date of transactions. Exchange differences arising, if any, are recognised in Other comprehensive income and in the Enlarged Group's equity reserves. Upon disposal of an operation, the amounts accumulated in the foreign currency translation reserve are recognised as income or expense in the period in which the operation is disposed of.

Borrowing costs

Finance costs of debt are allocated to periods over the term of the related debt at a constant rate on the carrying amount. Arrangement

fees and issue costs are deducted from the debt proceeds on initial recognition of the liability and are amortised and charged to finance costs over the expected life of the debt.

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are capitalised, until such time as the assets are substantially ready for their intended use or sale. All other borrowing costs are recognised in the consolidated statement of comprehensive income in the period in which they are incurred.

Financial instruments

Financial assets and financial liabilities are recognised on the Enlarged Group's balance sheet when the Enlarged Group becomes party to the contractual provision of the instrument.

Effective interest method

The effective interest method is a method of calculating the amortised cost of an interest bearing financial asset or liability and for allocating interest income or expense over the relevant period. The effective interest rate is the rate that discounts estimated future cash receipts or payments to present value (including all fees on points paid or received that form an integral part of the effective interest rate, transaction costs and other premiums or discounts) through the expected life of the financial asset or liability, or, where appropriate, a shorter period.

Financial assets

All financial assets are initially measured at fair value. Financial assets are classified into the following specified categories: financial assets "at fair value through profit or loss" ("FVTPL"), "held-to-maturity" investments, "available-for-sale" financial assets and "loans and receivables". The classification depends on the nature and purpose of the financial assets and is determined at the time of initial recognition. All of the Enlarged Group's financial assets are currently classified as "loans and receivables".

Loans and receivables

Trade receivables, loans, and other receivables that have fixed or determinable payments that are not quoted in an active market are classified as loans and receivables. Loans and receivables are measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate, except for short-term receivables when the recognition of interest would be immaterial.

Impairment of financial assets

Financial assets are assessed for indicators of impairment at each balance sheet date. Financial assets are impaired where there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the financial asset have been impacted. For financial assets measured at amortised cost, if there is objective evidence of impairment, the impairment is measured as the difference between the present value of estimated future cash flows discounted at the instrument's original effective interest rate less the carrying value of the financial asset.

The carrying amount of the financial asset is reduced by the impairment loss directly for all financial assets with the exception of trade receivables, where the carrying amount is reduced through the use of an allowance account. When a trade receivable is considered uncollectible, it is written off against the allowance account. Subsequent recoveries of amounts previously written off are credited against the allowance account. Changes in the carrying amount of the allowance account are recognised in the consolidated statement of comprehensive income.

Trade receivables

Trade receivables are measured at their fair value upon initial recognition. Appropriate allowances for estimated irrecoverable amounts are recognised in the consolidated statement of comprehensive income when there is objective evidence that the asset is impaired.

Cash and cash equivalents

Cash and cash equivalents consist of cash at bank or in hand and short-term deposits with an original maturity of three months or less. In addition, the Enlarged Group holds a number of restricted cash balances relating to deposits and cash balances associated with the Enlarged Group's borrowing facilities. These amounts are shown within the Seven Group's receivable balances.

Derecognition of financial assets

The Enlarged Group derecognises a financial asset only when the contractual rights to the cash flows from the asset expire; or it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another entity.

Financial liabilities and equity

Financial liabilities and equity instruments are classified according to the substance of the contractual arrangements entered into and the definitions of a financial liability and equity instrument.

Equity instruments

An equity instrument is any contract that evidences a residual interest in the assets of the Enlarged Group after deducting all of its liabilities. Equity instruments issued by the Enlarged Group are recorded at the proceeds received, net of direct issue costs.

Compound instruments

The component parts of compound instruments issued by the Enlarged Group are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangement. At the date of issue, in the case of a bond denominated in the functional currency of the issuer that may be converted into a fixed number of equity shares, the fair value of the liability component is estimated using the prevailing market interest rate for a similar non-convertible instrument. This amount is recorded as a liability on an amortised cost basis using the effective interest method until extinguished upon conversion or at the instrument's maturity date. The equity component is determined by deducting the amount of the liability component from the fair value of the compound instrument as a whole at initial recognition. This is recognised and included in equity, net of income tax effects, and is not subsequently re-measured.

Issue costs are apportioned between the liability and equity components of the convertible loan notes based on their relative carrying amounts at the date of issue. The portion relating to the equity component is charged directly against equity.

Financial liabilities

Financial liabilities are classified as either financial liabilities at fair value through profit and loss ("FVTPL") or held at amortised cost.

Financial liabilities at FVTPL

Financial liabilities are classified as at FVTPL when the financial liability is either held for trading or is designated as at FVTPL.

A financial liability is classified as held for trading if:

- it has been incurred principally for the purpose of repurchasing it in the near term; or
- on initial recognition it is part of a portfolio of identified financial instruments that the Group manages together and has a recent actual pattern of short-term profit-taking; or
- it is a derivative that is not designated or effective as a hedging instrument.

A financial liability other than a financial liability held for trading may be designated as at FVTPL upon initial recognition if:

- such designation eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise; or
- the financial liability forms part of a group of financial assets or financial liabilities or both, which is managed and its performance is evaluated on a fair value basis, in accordance with the Group's

documented risk management or investment strategy, and information about the grouping is provided internally on that basis; or

- it forms part of a contract containing one or more embedded derivatives, and IAS 39 Financial Instruments: Recognition and Measurement ("IAS 39") permits the entire combined contract (asset or liability) to be designated as at FVTPL.

Financial liabilities at FVTPL are stated at fair value, with any gain or losses arising on re-measurement recognised in the consolidated statement of comprehensive income. The net gain or loss recognised in the consolidated statement of comprehensive income incorporates any interest paid on the financial liability and is included in the finance costs line item in the consolidated statement of comprehensive income.

Other financial liabilities

Other financial liabilities, including borrowings and trade and other payables, are initially measured at fair value, net of transaction costs. Other financial liabilities are subsequently measured at amortised cost using the effective interest method, with interest expense recognised on an effective yield basis, except for short-term trade payables when the recognition of interest would be immaterial.

Derecognition of financial liabilities

The Enlarged Group derecognises financial liabilities when, and only when, the Enlarged Group's obligations are discharged, cancelled or they expire.

Embedded derivatives

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contracts and the host contracts are not measured at FVTPL.

An embedded derivative is presented as a non-current asset or non-current liability if the remaining maturity of the hybrid instrument to which the embedded derivative relates is more than 12 months ahead and is not expected to be realised or settled within 12 months. Other derivatives are presented as current assets or current liabilities.

Share-based payments

The Enlarged Group makes equity-settled share-based payments to certain employees. Equity-settled share-based schemes are measured at fair value (excluding the effect of non-market-based vesting conditions) at the date of grant, measured by use of an option valuation model. The expected lives of the options used in the model are adjusted, based on management's best estimate, for the effects of non-transferability, exercise restrictions and behavioural considerations.

The fair value determined at the grant date of the equity-settled share-based payments is expensed on a straight-line basis over the vesting period, based on the Enlarged Group's estimate of shares that will eventually vest.

At each balance sheet date, the Enlarged Group revises its estimate of the number of equity instruments expected to vest as a result of the effect of non-market-based vesting conditions. The impact of the revision of the original estimates, if any, is recognised in the consolidated statement of comprehensive income such that the cumulative expense reflects the revised estimate, with a corresponding adjustment to the equity reserve.

Retirement benefit costs

Payments to defined contribution retirement benefit schemes are charged as an expense as they fall due. Payments made to state-managed retirement benefit schemes are dealt with as payments to defined contribution schemes where the Enlarged Group's obligations under the schemes are equivalent to those arising in a defined contribution retirement benefit scheme. The Enlarged Group had no defined benefit schemes in place during the periods presented.

Taxation

Tax expense represents the sum of the tax currently payable and deferred tax. The tax currently payable is based on taxable profit for the period. Taxable profit differs from net profit/loss as reported in the consolidated statement of comprehensive income because it excludes items of income or expense that are taxable or deductible in other years and it further excludes items that are never taxable or deductible. The Enlarged Group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted at the balance sheet date.

Deferred tax is the tax expected to be payable or recoverable on differences between the carrying amounts of assets and liabilities in the Financial Statements and the corresponding tax bases used in the computation of taxable profit, and is accounted for using the balance sheet liability method. Deferred tax liabilities are generally recognised for all taxable temporary differences and deferred tax assets are recognised to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilised. Such assets and liabilities are not recognised if the temporary difference arises from the initial recognition of goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Deferred tax liabilities are recognised for taxable temporary differences arising on investments in subsidiaries and associates, and interests in joint ventures, except where the Enlarged Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered.

Deferred tax is calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realised. Deferred tax is charged or credited in the statement of comprehensive income, except when it relates to items charged or credited directly to other comprehensive income or equity, in which case the deferred tax is also recognised in other comprehensive income or equity.

Current and deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Enlarged Group intends to settle its current tax assets and liabilities on a net basis.

Provisions

Provisions are recognised when the Enlarged Group has a present obligation as a result of a past event, and it is probable that the Enlarged Group will be required to settle that obligation. Provisions are measured at the Enlarged Group's best estimate of the expenditure required to settle the obligation at the balance sheet date, taking into account the risks and uncertainties of the obligation, and are discounted to present value where the effect is material.

Operating leases

Rentals payable under operating leases are charged to income on a straight-line basis over the term of the relevant lease.

3. Adoption of new and revised standards

New standards and interpretations adopted with no significant effect on the Financial Statements

The following new standards and amendments resulting from improvements to IFRS standards and interpretations are effective and have been adopted. Their impact on the consolidated financial statements is not considered to be material.:

Amendment to IAS 12: 'Recognition of Deferred Tax Assets for Unrealised Losses'
Amendment to IAS 7: 'Disclosure Initiative'
Annual Improvements to IFRS 2014-2016 Cycle

New standards and interpretations in issue but not yet effective

The following new standards and amendment are in issue but are not yet effective. They are relevant to the Seven Group and result from improvements to IFRS standards and interpretations.

The impacts of IFRS 15: Revenue from Contracts with Customers and IFRS 16: Leases have not been assessed.

The impact of the following new standards and interpretations has not been assessed:

IFRS 9: 'Financial Instruments'
IFRIC 22: 'Foreign currency transactions and advanced consideration'
Clarifications to IFRS 15: 'Revenue from contracts with customers'
Amendment to IFRS 2: 'Classification and measurement of share based payment transactions'
Amendment to IAS 12: 'Recognition of Deferred Tax Assets for Unrealised Losses'

4. Critical accounting judgements and key sources of estimation uncertainty

The Savannah Directors and management are required to make judgements, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, and the accompanying disclosures, and the disclosure of contingent liabilities at the date of the consolidated financial statements. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates. The estimates and underlying assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Revisions to accounting estimates are recognised in the period in which the estimate is revised, if the revision affects only that period, or in the period of the revision and future periods if the revision affects both current and future periods. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities affected in future periods.

The Enlarged Group has identified the following areas where critical accounting judgements, estimates and assumptions are required. Further information on each of those areas and how they impact the various accounting policies are described below and also in the relevant note to the Consolidated Financial Statements.

Critical accounting judgements

Going concern

Further details are provided in note 2 to the Financial Statements.

Strategic Alliance Agreement ("SAA")

General Information on the SAA

The Seven Group entered into a SAA with the Nigerian Petroleum Development Company ("NPDC") in November 2010 to provide technical services and to fund 100 per cent. of NPDC's share of capex and opex from its 55 per cent. interest in the Joint Operating Agreement for OMLs 4, 38 and 41, for which SEPLAT Petroleum ("the operator") is the operator. The Seven Group paid an entrance fee of $54 million to enter into the SAA. In return, the Seven Group recovers its cost via cost oil and is also entitled to a share of profit oil.

A key area of judgement is that the Seven Group accounts for the SAA as a jointly controlled operation (i.e. full consolidation of the Seven Group's 55 per cent. share) despite not being part of the legal Joint Operating Agreement between the operator and NPDC. The Savannah Directors believe this judgement to be appropriate on the basis that joint control is exercised through the participation of the Seven Group in technical and financial discussions, participation in the decision making process for the development of the OMLs through NPDC, and also the funding of NPDC's 55 per cent. share of costs. Joint control is exhibited by the fact that the Seven Group and NPDC have equal voting powers on developments and operations, with the other Joint Operating Agreement participants. The Seven Group can also veto any strategic, financial and/or operating decisions related to the SAA.

Accounting Measurement and Disclosure of SAA

The SAA with NPDC relies on an agreed financial model to determine the Seven Group's production entitlement from this agreement. Within this model, current year operating and capital expenditure costs are initially estimated from monthly cash calls (issued by the operator based on expected expenditure for the coming month) and then actualised once cost returns are agreed by the operator, resulting in either an over or an under-funded position. Daily field production rates are adjusted to reflect expected terminal throughput rates based on past experience and then trued up for actual throughput by the terminal operator. The Seven Group's share of production is determined at different percentage rates based on both baseline and incremental production volumes which change over the course of the contract. In the following year, NPDC and the operator formally approve the cost performance for the prior year. As such, adjustments to operating costs, capital expenditures, production entitlement and depletion are made in the year of agreement. Adjustments to tangible assets as a result of formal approval of costs are separately disclosed in note 17. Occasionally, residual costs relating to other prior years are also submitted and agreed, and the impact of these additional revisions are also reflected in the current year.

The Seven Group recognises revenue under the SAA on a liftings basis (i.e. reflecting actual oil barrels lifted and sold by the Seven Group) which historically has differed from the Seven Group's entitled share of oil barrels under the agreement. This gives rise to an underlift, which is a balance resulting from oil produced not being sold in entirety. As the Seven Group bases entitlement on cash calls/returns received by NPDC, which are subject to revisions and approvals post-year end (as explained above), changes to the Seven Group's entitlement and therefore to capex, production expenses, underlift and depletion occur in the subsequent period. The cash calls are based on the 55 per cent. share of costs carried by the Seven Group.

During 2014 NPDC reached agreement with the operator in relation to past costs incurred in the year ended 31 December 2013, which were initially estimated and unapproved by NPDC. This resulted in reduced operating and capital expenditure being attributed to the Seven Group. An equivalent agreement process was conducted in 2015. This also led to a reduction in operating and capital expenditure being attributed to the Seven Group. In 2016, the equivalent process resulted in an increase in operating and capital expenditure being attributed to the Seven Group. More detail can be found in note 17.

2016 Forcados Terminal Shutdown

Damage to the Trans Forcados pipeline in February 2016 led to a prolonged pipeline and export terminal shutdown throughout 2016. This resulted in NPDC being unable to allocate oil liftings to the Seven Group, which also adversely impacted the Seven Group's ability to fund unpaid cash calls.

Discussions between NPDC and the Seven Group continued throughout 2016 and into early 2017 to positively address the above challenges faced. This resulted in a funding protocol, informally agreed in June 2016, whereby NPDC agreed to pay all the cash calls associated with the OML's expenditures in 2016. The accounting position recorded in the financial statements reflected the economic substance of these agreements even where, in some circumstances, the legal documentation was not formalised.

As a result, the Seven Group was not presented with any costs in 2016 to pay on behalf of NPDC and accordingly no expenditures were recorded or payables recognised by the Seven Group for any 2016 activity at the OML's 4, 38 & 41. Consequently, production entitlement recorded in 2016 reflected the Seven Group's entitlement arising from historic capital expenditure incurred on behalf of NPDC in previous years. This information can be seen in Note 7. This accounting treatment initially continued until February 2017.

The Forcados shutdown resulted in an impairment of $183.3 million to the SAA in 2016.

2017 Impairment Indicator and Testing

In February 2017, the Seven Group received a notice from NPDC of its intention to terminate the SAA. The Seven Group obtained a legal injunction to prevent any termination as the Seven Group believed that there was no legal basis to do so. Thereafter, the Seven Group continued with out of court discussions with NPDC aimed at amicably resolving the situation. Whilst discussions are still ongoing, the Seven Group anticipates that reinstatement of the SAA would require a substantial front-end cash payment of accrued legacy costs and a working capital injection. The quantum of this is still subject to negotiation and agreement with NPDC, but it is likely that a net investment of up to $200 million will be required to reinstate the SAA.

Given the contractual uncertainty, the ongoing resolution discussions and the significant funding requirement, Savannah believes there is sufficient evidence to impair the carrying value of the SAA assets to its estimated recoverable amounts. Part of the out of court discussions with NPDC involved a reconciliation process to determine the outstanding balances as at 31 December 2015 – no activity for 2016 and 2017 has been recorded since 1 January 2016. Included in this process was a review of the agreed financial model used to determine the Group's production entitlement. In order to facilitate the out of court settlement process, the lower oil tax rate for new entrants for the first five years was deemed to be no longer applicable, although contractually agreed between the parties on commencement. The full oil tax rate was therefore retrospectively applied to the financial model. This change in rate does not impact taxation payable but effects the amount of entitlement the Seven Group receive as determined by the SAA.

This reconciliation determined that the Seven Group was entitled to: $163 million of unrecovered capital expenditures (before discounting of $35 million), $194 million of current oil underlift (note 20) and unpaid cash calls of $361 million (note 22). Although no formal agreement has been reached with NPDC, the Seven Group believes that these reconciled amounts are its best estimates of the recoverable and payable amounts. The estimated balances are subject to change depending on the final agreement with the NPDC. As such, in 2017, the Seven Group impaired its underlift balance by $97 million and impaired its carrying value of the SAA Upstream assets by $222 million (inclusive of the discounting, note 17) to reflect those estimates. The overall closing position on the SAA is as at 30 June 2017. This position remains an issue for the Seven Group to resolve with NPDC and does not form part of the Agreed Transaction with Savannah.

Estimation uncertainty

Upstream and infrastructure oil and gas assets (estimation of oil and gas reserves)

The determination of the Enlarged Group's estimated oil and natural gas reserves requires significant judgements and estimates to be applied and these are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, drilling of new wells, and commodity prices all impact on the determination of the Enlarged Group's estimates of its oil and natural gas reserves. The Enlarged Group employs independent reserves specialists who periodically report on the Enlarged Group's level of commercial reserves by evaluating the estimates of the Enlarged Group's in-house reserves specialists and where necessary referencing geological, geophysical and engineering data together with reports, presentation and financial information pertaining to the contractual and fiscal terms applicable to the Enlarged Group's assets. In addition, the Enlarged Group undertakes its own assessment of commercial reserves, using standard evaluation techniques and related future capital expenditure by reference to the same datasets using its own internal expertise.

In compiling the HFI, Savannah's own reserves estimations have been considered in arriving at the correct carrying value of oil and gas assets.

The estimates adopted by the Enlarged Group may differ from the independent reserves specialists' estimates where management considers that adjustments are appropriate in the circumstances. The last assessment by its independent reserves specialist was as at 30 June 2017.

Oil and gas reserves also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements. If reserves estimates are revised downwards, earnings could be affected by changes in depreciation expense or an immediate write-down of the property's carrying value. Information on the carrying amounts of the Seven Group's oil and natural gas properties, together with the amounts recognised in the income statement as depreciation, depletion and amortisation, is contained in Note 16 and Note 17.

Impairment of upstream and infrastructure oil and gas assets

Management compares the carrying value of its oil and gas assets to the estimated value-in-use of the underlying oil and gas reserves and related future cash flows that could be generated from these reserves.

Determination as to whether, and by how much, an asset is impaired involves management applying its latest development plans and business strategies along with estimates on highly uncertain matters such as future commodity prices, operational down-time assumptions for oil export lines and terminals, the effects of inflation on operating expenses, discount rates applied, production profiles and the outlook for regional market supply-and-demand conditions from our gas offtakers, including the performance of the wider power and industrial sectors that rely on gas as feedstock.

For value-in-use calculations, future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The pre-tax discount rate is derived from the cost of funding the Seven Group has calculated using an established model. The discounts rate applied in assessments of impairment are reassessed each year. Reserves assumptions for value-in-use tests are restricted to prove and probable reserves.

The reserve and resources estimates are management's best estimates and are described above in – Upstream oil and gas reserves and resources.

Details of impairment charges recognised in the income statement and details on the carrying amounts of assets are shown in note 17, along with disclosures on key estimates used in impairment assessments.

Decommissioning

The Seven Group has decommissioning obligations in respect of certain of its oil and gas interests and related midstream infrastructure. The extent to which a provision is recognised requires management to make judgements on the legal and constructive obligations at the date of decommissioning, the level of future abandonment, work required and timing.

In calculating the decommissioning cost/provision, an assessment is made based on the different asset categories: facilities, pipelines and wells. For facilities, internal experts use the P90 estimation (using the Monte-Carlo model, where P90 is the high side cost).For the pipelines, an independent external expert is employed to value decommissioning and the Most Likely (ML) case is applied. The Seven Group's internal experts on wells carried out a detailed assessment in line with a class 3 estimation method. This estimation method is as per the Cost Estimate Classification System (source: AACE International).

Estimating the decommissioning provision relies on professional judgement and is an area of accounting susceptible to material changes over the life of the product. The Seven Group will at least be partially aware of what needs to be decommissioned (some capex will only be incurred in the future and therefore what ultimately needs to be decommissioned may not be immediately determinable) but the value of the ultimate cash outflow could be materially affected by a variety of factors, including (but not limited to): technology available at the time of decommissioning, fiscal/regulatory climate, potential for life extension of facilities, potential value of "scrap", inflation and exchange rates.

For the six months ended 30 June 2017, the combined discount rate applied to future decommissioning expenditure was 10.73 per cent. (2016: 10.91 per cent., 2015: 8.87 per cent., 2014: 7 per cent.). The blended inflation rate for the six months ended 30 June 2017 was 5.54 per cent. (2016: 5.75 per cent., 2015: 5.59 per cent., 2014: 4.54 per cent.). Although Savannah does not yet have decommissioning responsibilities as a result of its exploration phase, Savannah management is comfortable with the rates and assumptions used by the Seven Group. Combined/blended rates are required as result of both the United States Dollar and Nigerian Naira being used in the operations of the Seven Group.

Deferred Tax

The recoverability of the deferred tax asset recognised throughout the review period is based on forecasted taxable profits for the Seven Group, against which the deferred tax asset currently recognised will be able to be fully utilised. The Seven Group's operations are considered to be in their early stages. As such, it was expected that significant capex and losses would be incurred before a full ramp-up and meaningful profitability. This trend is usual for an extractive industry. A deferred tax asset has been recognised primarily in relation to unutilised tax losses and accelerated capital allowances on fixed assets. Further detail on the deferred tax asset recognised can be found in note 23. As part of the Agreed Transaction, the assets being targeted carry $67.7 million of unutilised losses and accelerated capital allowances, which Savannah believes will be available to the Enlarged Group post transaction.

5. Revenue

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Oil sales	344,426	261,193	11,503	7,234	9,339
Gas sales	33,729	92,378	90,417	59,304	52,411
Revenue	378,155	353,571	101,920	66,538	61,750
Investment revenue	83	536	505	326	16
Total	378,238	354,107	102,425	66,864	61,766

Revenue from oil sales for 2014 and 2015 primarily relates to the Seven Group's sale of oil lifted from the SAA. During 2015 the Seven Group also commenced oil sales from its Uquo and Stubb Creek fields in the South-east Niger Delta.

Following a declaration by ExxonMobil (the offtaker for Uquo and Stubb Creek oil) in 2016, Oil sales from the Uquo and Stubb Creek fields were interrupted. This was due to damage to the export terminal at Qua Iboe, which led to no exports between 18th July and 24th September 2016. Sales have since recommenced.

No oil liftings were received under the SAA during 2016 as a result of the closure of the Forcados terminal in mid-February 2016 and the declaration of force majeure by Shell (the terminal operator), which was only lifted in June 2017. The Group sells its oil entitlement from the OMLs 4, 38 & 41 via this terminal. For further detail on the SAA, refer to note 4 "Critical accounting judgements and key sources of estimation uncertainty". Note that Savannah is not acquiring the SAA and therefore, prospectively, no revenue will be reported on this asset in the Enlarged Group's results.

Revenue from gas sales represents deliveries from the Seven Group's south east Niger Delta gas infrastructure business to its gas customers in the region, including the power generation and industrial sector. Gas customers reduced down to 3 in the half year to June 2017 (2016: 5, 2015: 5, 2014: 2).

6. Production Expenses

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Production costs – oil	208,678	155,758	7,741	3,667	4,044
Production costs – gas	23,058	34,642	26,816	18,454	10,330
	231,736	190,400	34,557	22,121	14,374

Oil production costs for 2014 and 2015 relate primarily to the Seven Group's share of production costs associated with the SAA. During 2015 oil production also commenced at the Uquo and Stubb Creek fields, which introduced additional production expenses.

The decrease in production costs in 2016 and 2017 largely reflects the agreement reached with NPDC in the last quarter of 2016, whereby NPDC would fund all the 2016 cash calls due under the SAA and therefore no share of operator costs was recorded by the Seven Group for any 2016 or 2017 activity. For further detail on the SAA, refer to note 4 "Critical accounting judgements and key sources of estimation uncertainty".

Gas production costs relate to production and delivery of gas from the Uquo field.

7. Business and geographical segments

The accounting policies of the reportable segments are the same as the Seven Group's accounting policies described in note 2. Segment operating result represents the profit/(loss) by each segment without allocation of central administration costs, investment revenue, finance costs, and tax expense. Segment operating results are provided to the Seven Board for the purpose of resource allocation and assessment of segment performance. Savannah intends on managing the segments in a similar way, however this will only include assets included within the Agreed Transaction. Segmental analysis will therefore exclude the North-west region (the SAA) and the Anambra basin. Accugas (which forms part of the South-east region) will be managed separately, in conjunction with certain third-party investors.

The Savannah directors are of the opinion that the Seven Group is engaged in business with clear operating segments, which are categorised by geographic region. The chief operating decision maker is considered to be the Seven Board of Directors, which is provided with this information on a monthly basis. The Savannah Board will be responsible for this on completion of the Agreed Transaction.

As disclosed in Note 1, Savannah are acquiring certain assets of the Seven Group. The assets being purchased relate to the South East Region (Stubb Creek, Uquo and a 20 per cent. interest in Accugas). The North West Region relates to the Strategic Alliance Agreement and the Anambra Basin relates to the Intangible assets and neither of these segments form part of the Agreed Transaction. The following is an analysis of the Seven Group's revenue and results by reportable segment:

	North-west June 2017 $000	South-east June 2017 $000	Anambra basin June 2017 $000	Corporate June 2017 $000	Total June 2017 $000
Revenue	–	61,750	–	–	61,750
Change in underlift	(97,182)	–	–	–	(97,182)
Production expenses	(434)	(13,940)	–	–	(14,374)
Depletion	–	(16,096)	–	–	(16,096)
Gross profit/(loss)	(97,616)	31,714	–	–	(65,902)
Depreciation and amortisation	–	(486)	–	(153)	(639)
Impairment charge	(221,692)	–	–	–	(221,692)
Other operating income/(costs)	5	6,459	(2,152)	–	4,312
Restructuring expenses	–	–	–	(3,057)	(3,057)
Administrative expenses	(105)	(4,826)	(33)	(3,726)	(8,690)
Segment operating result	(319,408)	32,861	(2,185)	(6,936)	(295,668)
Investment revenue	–	9	–	7	16
Finance costs	(26,569)	(32,236)	–	(823)	(59,628)
Foreign exchange – realised	1	(2,275)	–	5	(2,269)
– unrealised	(8)	3,288	(28)	(53)	3,199
Loss before tax	(345,984)	1,647	(2,213)	(7,800)	(354,350)
Tax credit					27,980
Loss for the year					(326,370)

	(Unaudited) North-west June 2016 $000	(Unaudited) South-east June 2016 $000	(Unaudited) Anambra basin June 2016 $000	(Unaudited) Corporate June 2016 $000	Total June 2016 $000
Revenue	–	66,538	–	–	66,538
Change in underlift	29,102	(337)	–	–	28,765
Production expenses	(1,595)	(20,526)	–	–	(22,121)
Depletion	(7,637)	(27,009)	–	–	(34,646)
Gross profit/(loss)	19,870	18,666	–	–	38,536
Depreciation and amortisation	–	(830)	(5)	(349)	(1,184)
Impairment (charge)/reversal	–	–	–	–	–
Other operating income/(costs)	8,170	(1,147)	–	–	7,023
Restructuring expenses	–	(4,965)	–	(1,978)	(6,943)
Administrative expenses	(79)	(6,918)	(107)	(6,124)	(13,228)
Segment operating result	27,961	4,806	(112)	(8,451)	24,204
Investment revenue	–	7	–	319	326
Finance costs	(25,318)	(30,488)	–	4,020	(51,786)
Foreign exchange – realised	235	8,270	1	2,857	11,363
– unrealised	20	28,663	(176)	(151)	28,356
Loss before tax	2,898	11,258	(287)	(1,406)	12,463
Tax credit					(3,988)
Loss for the year					8,475

	North-west December 2016 $000	*South-east December 2016 $000*	*Anambra basin December 2016 $000*	*Corporate December 2016 $000*	*Total December 2016 $000*
Revenue	–	101,920	–	–	101,920
Change in underlift	69,797	–	–	–	69,797
Production expenses	(4,349)	(30,208)	–	–	(34,557)
Depletion	(20,713)	(24,890)	–	–	(45,603)
Gross profit/(loss)	44,735	46,822	–	–	91,557
Depreciation and amortisation	–	(1,227)	(9)	(522)	(1,758)
Impairment (charge)/reversal	(183,354)	–	(115,736)	–	(299,090)
Other operating income/(costs)	7,179	(3,672)	–	–	3,507
Restructuring expenses	–	(4,965)	–	(1,977)	(6,942)
Administrative expenses	(244)	(16,134)	(163)	(9,222)	(25,763)
Segment operating result	(131,684)	20,824	(115,908)	(11,721)	(238,489)
Investment revenue	–	18	–	487	505
Finance costs	(54,917)	(51,270)	–	(1,424)	(107,611)
Foreign exchange – realised	272	5,846	(6)	3,162	9,274
– unrealised	42	25,302	(211)	8,487	33,620
Loss before tax	(186,287)	720	(116,125)	(1,009)	(302,701)
Tax credit					95,528
Loss for the year					(207,173)

	North-west December 2015 $000	*South-east December 2015 $000*	*Anambra basin December 2015 $000*	*Corporate December 2015 $000*	*Total December 2015 $000*
Revenue	248,007	105,564	–	–	353,571
Change in underlift	(63,523)	1,538	–	–	(61,985)
Production expenses	(147,261)	(43,139)	–	–	(190,400)
Depletion	(59,910)	(29,046)	–	–	(88,956)
Gross profit/(loss)	(22,687)	34,917	–	–	12,230
Depreciation and amortisation	–	(2,539)	(40)	(741)	(3,320)
Impairment (charge)/reversal	(90,381)	–	–	–	(90,381)
Other operating income/(costs)	(174)	(3,121)	–	–	(3,295)
Restructuring expenses	–	–	–	–	–
Administrative expenses	(400)	(17,206)	(337)	(17,310)	(35,253)
Segment operating result	(113,642)	12,051	(377)	(18,051)	(120,019)
Investment revenue	228	71	–	236	535
Finance costs	(46,692)	(55,096)	–	(1,632)	(103,420)
Foreign exchange – realised	26	1,947	–	2	1,975
– unrealised	23	4,960	(58)	26	4,951
Loss before tax	(160,057)	(36,067)	(435)	(19,419)	(215,978)
Tax credit					78,438
Loss for the year					(137,540)

	North-west December 2014 $000	South-east December 2014 $000	Anambra basin December 2014 $000	Corporate December 2014 $000	Total December 2014 $000
Revenue	345,436	32,719	–	–	378,155
Change in underlift	190,620	–	–	–	190,620
Production expenses	(205,121)	(26,615)	–	–	(231,736)
Depletion	(90,667)	(29,606)	–	–	(120,273)
Gross profit/(loss)	240,268	(23,502)	–	–	216,766
Depreciation and amortisation	–	(2,328)	(15)	(657)	(3,000)
Impairment (charge)/reversal	–	(546,239)	–	–	(546,239)
Other operating income/(costs)	(247)	(4,678)	–	–	(4,925)
Restructuring expenses	–	–	–	–	–
Administrative expenses	(3,475)	(28,902)	(256)	(26,098)	(58,731)
Segment operating result	236,546	(605,649)	(271)	(26,755)	(396,129)
Investment revenue	–	–	–	–	83
Finance costs	–	–	–	–	(76,181)
Foreign Exchange Gains – realised	–	–	–	–	–
– unrealised	–	–	–	–	7,821
Loss before tax	236,546	(605,649)	(271)	(26,755)	(464,406)
Tax credit					166,422
Loss for the year					(297,984)

Results for the North-west Niger Delta relate to the Seven Group's share of operating activities under the SAA. Historically, lifting quantities allocated to the Seven Group under this agreement have been notified by NPDC, which are sold to a third party offtaker via Shell's Forcados Export Terminal. In the South-east Niger Delta, revenues and expenditures predominantly relate to gas deliveries to the Seven Group's gas customers; and commencing in 2015, oil sales were made from the Uquo and Stubb Creek Fields to Exxon Mobil's Que Iboe Terminal.

Segment assets

Assets are not reported to the Chief Operating Decision Maker by Segment on a regular basis. Management monitor assets-based on classification as upstream assets. Infrastructure assets and Other Property, Plant and Equipment. Information on these assets is included within Note 7.

Other segment information additions to non-current assets

	North-west Jun-17 $000	South-east Jun-17 $000	Anambra basin Jun-17 $000	Corporate Jun-17 $000	Total Jun-17 $000
Capital Investment	–	1,594	–	–	1,594

	North-west Dec-16 $000	South-east Dec-16 $000	Anambra basin Dec-16 $000	Corporate Dec-16 $000	Total Dec-16 $000
Capital Investment	–	48,065	561	139	48,765

	North-west Dec-15 $000	South-east Dec-15 $000	Anambra basin Dec-15 $000	Corporate Dec-15 $000	Total Dec-15 $000
Capital Investment	125,295	88,428	40,632	1,651	256,006

	North-west Dec-14 $000	South-east Dec-14 $000	Anambra basin Dec-14 $000	Corporate Dec-14 $000	Total Dec-14 $000
Capital Investment	407,900	489,592	64,131	1,062	962,685

8. Other operating expenses

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*(Unaudited) six months ended 30 June 2016 $000*	*Six months ended 30 June 2017 $000*
Total other operating income/(expenses)	(4,925)	(3,295)	3,507	7,023	4,312

Net other operating income mainly relates to the release of provisions relating to oil and gas levies. The increase in operating income in 2016 principally relates to the release of a VAT accrual associated with the SAA, along with the release of some pre-acquisition subsidiary liabilities no longer required. Operating expenses include levies charged by the Nigeria Delta Development Company (NDDC). This levy is calculated based on annual budget and is used to tackle ecological problems which arise from oil exploration and exploitation.

9. Administrative expenses

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*(Unaudited) six months ended 30 June 2016 $000*	*Six months ended 30 June 2017 $000*
Gross staff costs (note 12)	40,755	32,192	22,168	14,862	8,254
Other administrative expenses	33,080	20,396	14,646	7,465	4,519
Timewriting recharges to capital projects or production expenses	(15,104)	(17,335)	(11,051)	(9,099)	(4,083)
Total other operating (income)/expenses	58,731	35,253	25,763	13,228	8,690

Certain employees are required to complete timesheets as a basis to recharge their time spent on the Seven Group's various operations and capital expenditure programmes. This involves calculating a charge out rate for each relevant employee based on their direct remuneration and an element of the Seven Group's overhead. See note 12 for further details.

10. Restructuring expenses

During the six months ended 30 June 2017, the Seven Group incurred expenses of $3.1 million (June 2016 and December 2016: $6.9m) in advisory fees relating to the restructuring of the Seven Group. In 2016, the Seven Group began incurring expenses in connection with reorganisation in order to reduce the cost base; the amount mainly relates to staff redundancy costs and other associated payments.

11. Foreign exchange gains and losses

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Realised gains/(losses)	429	1,974	9,274	11,363	(2,269)
Unrealised gains/(losses)	7,392	4,951	33,620	28,356	3,199
Total foreign exchange gains	7,821	6,925	42,894	39,719	930

The unrealised gain in 2016 related mainly to the purchase of Naira with US Dollars at a more favourable rate compared to the central bank rate, due to the exchange rate market in Nigeria. This unrealised gain arose as a result of the devaluation of the Naira to the US Dollar which took place in June 2016 and resulted in significant unrealised gains on Naira denominated borrowings and working capital liabilities.

12. Staff Costs

The average number of employees was:

	Year ended 31 December 2014 Number	Year ended 31 December 2015 Number	Year ended 31 December 2016 Number	(Unaudited) six months ended 30 June 2016 Number	Six months ended 30 June 2017 Number
Management	4	4	5	5	5
Operations and support staff	116	123	102	120	81
Administration	69	71	66	71	54
Total number of employees	189	198	173	196	140

Their aggregate remuneration comprised:

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Wages and salaries	31,113	22,292	15,486	11,572	6,204
Social security costs	3,444	2,644	1,839	1,149	542
Defined contribution pension costs (note 28)	2,048	2,269	1,680	1,083	641
Gross expense of share-based payments (note 33)	4,150	4,987	3,163	1,058	867
Total staff costs	40,755	32,192	22,168	14,862	8,254

A portion of staff costs above were subsequently charged to the Seven Group's joint venture partners or capitalised through timewriting into the cost of fixed assets under the Seven Group's policy for Property, plant and equipment, or recharged through timewriting to Production expenses. The charge out rate via timewriting is comprised of direct remuneration as well as overhead costs absorbed which are indirectly relevant to employees (e.g. rent, security and IT).

13. Finance Costs

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Bank and other finance fees	21,031	12,452	15,142	7,312	10,972
Interest on bank loans and loan notes	61,142	90,282	98,439	47,879	47,632
Interest and other financial costs on convertible bonds	31,439	–	–	–	–
Total interest expense	113,612	102,734	113,581	55,191	58,604
Unwinding of discount on decommissioning provision (note 26)	1,118	2,766	2,165	1,223	1,024
Gain on redemption of convertible bonds	(182)	–	–	–	–
	114,548	105,500	115,746	56,414	59,628
Less: amounts capitalised in the cost of qualifying assets[i] (note 17)	(38,367)	(2,080)	(8,135)	(4,628)	–
Total finance costs	76,181	103,420	107,611	51,786	59,628

(i) Interest capitalised in 2015 and 2016 relates to general pool borrowings raised by the Seven Group's subsidiaries attributable to the construction of the Oron to Creek Town pipeline. In 2014, interest capitalised related to directly attributable borrowings raised for the construction of the completed Uquo to Oron pipeline as well as other Seven Group borrowings applied to qualifying additions. The Seven Group's capitalisation rate was 11.8 per cent. (2016: 11.8 per cent., 2015:11.7 per cent., 2014: 13.9 per cent.).

14. Tax

The tax expense/(credit) for the year is as follows:

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	(Unaudited) six months ended 30 June 2016 $000	Six months ended 30 June 2017 $000
Current tax					
Adjustment in respect of prior years	(330)	(7)	64	–	–
Current year	–	–	–	–	–
Deferred tax (note 23)					
Adjustment in respect of prior years	3,804	1,886	(1,962)	–	–
Current year	(182,482)	(67,730)	(93,630)	3,988	(28,354)
Tax expense/(credit) for the year	(179,008)	(65,851)	(95,528)	3,988	(28,354)

Corporation tax is calculated at the applicable tax rate for each jurisdiction based on the assessable profit or loss for the period. The Seven Group's outstanding current tax liabilities of $0.8 million (2016: $0.8 million, 2015: $0.7 million, 2014: $0.8 million) relate to corporation tax liabilities in Nigeria from prior years. In addition to corporation tax, the Seven Group incurs education tax and petroleum profits tax (PPT). PPT is a tax on the income of companies engaged in upstream petroleum operations in lieu of corporation tax. Education tax is imposed on every Nigerian resident company at a rate of 2 per cent. of the assessable profit for each year of assessment. PPT and education tax are not considered to be separate taxes – they are treated and paid alongside current taxation.

As part of the due diligence relating to the Agreed Transaction, Savannah has reviewed the tax exposures of the Seven Group and considers current provisions for tax to be appropriate.

The profit/(loss) for the period can be reconciled to the profit/(loss) before tax per the consolidated statement of comprehensive income as follows:

	Year ended 31 December 2014	*Year ended 31 December 2015*	*Year ended 31 December 2016*	*(Unaudited) six months ended 30 June 2016*	*Six months ended 30 June 2017*
(Loss)/profit before tax	(464,406)	(215,978)	(302,701)	12,463	(354,350)
Tax credit at the Nigerian corporation tax rate (30 per cent.):	(139,322)	(64,793)	(90,810)	3,739	(106,305)
Tax effects of:					
– Petroleum profits tax on oil activities	(39,265)	(15,383)	278	333	(290)
– Changes in effective future tax rates	(4,023)	417	–	–	–
– Education tax	4,396	(1,972)	(2,465)	(127)	(4,738)
– Expenses not deductible for tax purposes	3,016	2,493	2,419	(460)	8,301
– Unrecognised losses in head office and holding companies	12,660	6,553	8,750	(1,881)	5,073
– Other tax losses carried forward	77	220	182	–	–
– Other timing differences not recognised	939	2,020	8,160	(522)	718
– Profits/(losses) arising during tax holidays	11,098	2,715	21	2,932	(6,519)
– Initial Recognition of deferred tax assets	(32,059)	–	(22,046)	–	–
– Remeasurement of deferred tax liabilities	–	–	1,881	(26)	535
– Adjustments in respect of prior years	3,475	1,879	(1,898)	–	–
– De-recognition of deferred tax assets	–	–	–	–	74,871
Tax expense/(credit) for the year	(179,008)	(65,851)	(95,528)	3,988	(28,354)

15. Earnings per Share

The calculation of the basic and diluted (loss)/earnings per share is based on the following data:

	Year ended 31 December 2014	*Year ended 31 December 2015*	*Year ended 31 December 2016*	*(Unaudited) six months ended 30 June 2016*	*Six months ended 30 June 2017*
(Loss)/profit for the purposes of basic and diluted (loss)/earnings per share ($000)	(261,609)	(149,033)	(240,017)	8,399	(325,097)
Weighted average number of ordinary shares for the purposes of basic (loss)/earnings per share[1]	3,514,916	3,951,155	4,403,846	4,338,390	4,468,054
Weighted average number of ordinary shares for the purposes of diluted (loss)/earnings per share[1]	3,519,808	3,951,155	4,403,846	4,696,835	4,468,054
Basic (loss)/earnings per ordinary share ($)	(74.43)	(37.72)	(54.50)	1.94	(72.76)
Diluted (loss)/earnings per ordinary share ($)	(74.32)	(37.72)	(54.50)	1.79	(72.76)

1. The calculation of weighted average number of ordinary shares includes the weighted average number of shares that would be issued on conversion of the ICLNs as, for the reasons outlined in note 31, the ICLNs are believed to represent equity instruments of the Seven Group.

In 2017, there were 333,927 (2016: 358,445, 2015: 358,645, 2014: 302,261) of additional potentially dilutive instruments (being share options, warrants and ICLN pricing options) that were not included in the calculation of diluted earnings per share because they were anti-dilutive.

16. Intangible assets

Oil and gas exploration and appraisal assets

	Total *$000*
At 1 January 2014 (see note 18 for asset transferred to held for sale in 2013)	–
Additions	9,765
Acquisitions	64,131
At 31 December 2014	73,896
Additions	19,741
Transfers to property, plant and equipment (note 17)	(27,601)
Acquisitions (note 37)	38,678
At 31 December 2015	104,714
Additions	561
Reclassifications	(1,028)
Impairment charge	(104,247)
At 31 December 2016	–
Additions	–
Acquisitions	–
At 30 June 2017	–

Additions to oil and gas exploration and appraisal assets during 2014 related to expenditure on Uquo North East 1 prospect exploration well which was drilled at the end of 2014. Acquisitions in 2014 related to the Seven Group's acquisition of a 40 per cent. licence interest (60 per cent. economic interest) in Oil Prospecting Licence ("OPL 905") via its acquisition of the entire share capital of SRL 905 Holdings Limited on 31 January 2014.

Additions during 2015 relate to remaining expenditure to complete the Uquo North East 1 well, along with initial preparation work for future seismic studies on the Seven Group's Anambra basin assets. The Uquo North East 1 well successfully identified commercial quantities of oil and gas, such that $27.6 million of costs were transferred from intangible assets to Upstream assets within Property, plant and equipment (see note 17).

Acquisitions in 2015 related to the Seven Group's acquisition of a further 50 per cent. licence interest (36 per cent. economic interest) in OPL 905 via its acquisition of the entire share capital of Gas Transmission and Power Limited ("GTPL") on 27 February 2015. The Seven Group then held, in total, a 90 per cent. licence interest and 96 per cent. economic interest in OPL 905.

At 31 December 2016 a number of impairment triggers were apparent relating to the carrying value of the OPL 905 Anambra basin assets. These included the expiry of the exploration licence and that the Seven Group had not planned or budgeted for any substantive expenditure on this licence due to current funding constraints. Therefore, the carrying amount was written down to nil. The Anambra basin assets (which includes GTPL and any interest in OPL 905) are not being acquired as part of the Agreed Transaction.

17. Tangible Assets and PPE

Cost	*Upstream Assets[2] $000*	*Infrastructure assets $000*	*Other PP&E[1] $000*	*Total $000*
At 1 January 2014	939,437	559,348	13,405	1,512,190
Additions	444,353	120,024	4,222	568,599
Acquisitions (note 37)	–	269,822	81	269,903
Disposals	–	–	(505)	(505)
At 31 December 2014	1,383,790	949,194	17,203	2,350,187
Additions	125,294	53,904	1,756	180,954
Revisions to prior year joint venture cost estimates	(139,054)	–	–	(139,054)
Transfer from intangible assets (note 16)	27,601	–	–	27,601
Acquisitions (note 37)	–	–	24	24
Disposal	–	–	(3,013)	(3,013)
At 31 December 2015	1,397,631	1,003,098	15,970	2,416,699
Additions	2,251	45,472	481	48,204
Revisions to prior year joint venture cost estimates	(2,669)	–	–	(2,669)
Revisions to decommissioning provision (note 26)	(1,310)	(9,268)	–	(10,578)
Disposal	–	–	(2,826)	(2,826)
At 31 December 2016	1,395,903	1,039,302	13,625	2,448,830
Additions	859	736	–	1,595
Revisions to prior year joint venture cost estimates	6,935	–	–	6,935
Revisions to decommissioning provision (note 26)	713	1,828	–	2,541
Disposal	–	–	(780)	(780)
At 30 June 2017	1,404,410	1,041,866	12,845	2,459,121
Accumulated depreciation, depletion and impairment				
At 1 January 2014	(234,807)	(118,712)	(8,050)	(361,569)
Charge for the period	(93,366)	(26,907)	(3,000)	(123,273)
Impairment	(105,693)	(440,546)	–	(546,239)
Disposal	–	–	363	363
At 31 December 2014	(433,866)	(586,165)	(10,687)	(1,030,718)
Charge for the period	(75,448)	(13,508)	(3,320)	(92,276)
Impairment	(90,381)	–	–	(90,381)
Disposal	–	–	2,918	2,918
At 31 December 2015	(599,695)	(599,672)	(11,089)	(1,210,457)
Charge for the period	(34,615)	(10,988)	(1,758)	(47,361)
Impairment	(183,313)	(2)	–	(183,315)
Disposal	–	–	2,483	2,483
At 31 December 2016	(817,624)	(610,662)	(10,364)	(1,438,649)
Charge for the period	(8,826)	(7,270)	(639)	(16,735)
Impairment	(221,692)	–	–	(221,692)
Disposal	–	–	681	681
At 30 June 2017	(1,048,142)	(617,931)	(10,322)	(1,676,395)
Carrying Amount				
At 31 December 2014	949,924	363,029	6,516	1,319,469
At 31 December 2015	797,936	403,426	4,881	1,206,242
At 31 December 2016	578,279	428,640	3,261	1,010,181
At 30 June 2017	356,268	423,935	2,523	782,726

1. Other PP&E consists of vehicles, leasehold improvements and furniture, fixtures and equipment.
2. Upstream assets includes the SAA, Stubb Creek and Uquo.

The above note includes assets which are not being acquired as part of the Agreed Transaction. Within Upstream Assets, Savannah is not acquiring the SAA. Infrastructure Assets relate to the midstream side of the business (Accugas). As discussed in note 1, Savannah will only hold a 20 per cent. interest in Accugas.

The total value of the above assets is split as follows: SAA $128 million, Uquo $228 million, Stubb Creek $26 million and Accugas $398 million.

Decommissioning Asset

The decommissioning cost as at 30 June 2017 was $36.4 million (2016: $33.8 million, 2015: $44.4 million, 2014: $46 million). As at 30 June 2017, $26.1 million of this balance relates to infrastructure assets (2016: $24.3 million, 2015: $33.4 million, 2014: $35.4 million). The remainder as at 30 June 2017, being $10.3 million, relates to Upstream Assets (2016: $9.5 million, 2015: $11 million, 2014: $10.6 million).

Assets in the Course of Construction

The net book value of assets in the course of construction at 30 June 2017 was $nil (2016: $nil, 2015: $56.1 million, 2014: $100.6 million). Regarding the balances in 2014 and 2015, these were additions to upstream and infrastructure assets related to assets in the course of construction on the Uquo field, including the construction of the Oron to Creek Town gas pipeline. During 2014, $330.1 million of assets were transferred from assets in the course of construction being the Uquo to Oron pipeline, Stubb Creek field, FUN oil gathering manifold and second train of the Uquo gas processing facility.

Capitalised Interest

Additions for 2017 include no capitalised interest. There was $8.1 million worth of capitalised interest in 2016 (2015: $2.1 million, 2014: $38.4 million) from general borrowings raised by the Group for the construction of the Oron to Creek Town pipeline, using the Seven Group's capitalisation rate of 11.8 per cent. (2014: 13.9 per cent., 2015: 11.7 per cent.. In 2014, in addition to general borrowings, capitalised interest additions included directly attributable borrowings used to fund the now completed Uquo to Oron pipeline.

Fixed Charges

The Seven Group has granted fixed charges over $389.9 million (2016: $399.5 million, 2015: $523.8 million, 2014: $487.5 million) of its oil and gas assets to secure borrowings.

Acquisitions

Infrastructure asset acquisitions in 2014 include $269.8 million associated with the acquisition of East Horizon Gas Company Limited on 31 March 2014.

Revisions to Prior Year Charges (SAA)

In 2015, there were reductions in prior year capital expenditures of $139.1 million as a result of revisions made by the operator and NPDC to estimates of field expenditures. In 2016, this reduction was for $2.7 million and for the six months ended 30 June 2017, the revision resulted in an increase in $6.9 million to upstream asset cost. Further revisions could be made as part of a settlement agreement reached with NPDC. Refer to note 4 "critical accounting judgements and key sources of estimation uncertainty" for more detail on the accounting treatment of the SAA.

Transfers

Transfers during 2015 relate to costs incurred on drilling the Uquo North East-1 well which successfully identified commercial quantities of oil and gas, advancing the asset from the exploration and appraisal phase to development and production (note 17).

Impairments

The estimation of reserves is a key estimate in the preparation of these consolidated Financial Statements. Refer to note 4 for more detail. Increases in discount rates are predominantly as a result of the increase relating to Nigeria's economic deterioration.

a) North-west Impairment Testing (SAA)

In calculating the impairment on the SAA, a discount rate of 11.5 per cent. and 14 per cent. was used for the years ended 31 December 2015 and 31 December 2016 respectively. The oil price per barrel was taken as $55.00 for each year from 2017 onwards. These assumptions constitute the 'base case'.

The impairment to upstream assets in 2014 relates exclusively to the South-east region (see section (b) below).

In 2015, an impairment charge of $90.4 million on the SAA was made. This reflected the reduction in carrying value of capital expenditures of the north-west Niger Delta reporting segment, comprising the SAA. The impairment was largely as a result of the significant reduction in oil prices experienced during the year, and the revised future oil price forecasts compared to the previous year's impairment assessment, which had the effect of delaying the recovery of the Seven Group's cost oil and reducing the residual profit oil.

In 2016, the SAA was further impaired by $183.3 million. This was largely as a result of the ongoing disruption at the Trans Forcados oil terminal and the significant delay of when it became operational again, the impact of a contract dispute with NPDC on the SAA agreement, and a continued low oil price environment which has the effect of delaying the recovery of the Seven Group's cost oil and reduced any residual profit oil.

During 2017, a further impairment charge of $221.7 million was taken within upstream assets which reflected the reduction in carrying value of capital expenditures incurred in the SAA. The impairment for the six months ended 30 June 2017 was as a result of the termination notice issued by NPDC to the Seven Group. (see the SAA under note 4 "Critical accounting judgements and key sources of estimation uncertainty" for more detail).

Different scenarios were simulated to consider the sensitivity of impairments to changes in the base case assumptions.

With a lower oil price assumed (2017: $48/bbl, 2018: $50/bbl, 2019 onwards: $52/bbl), the net asset value reduces by $14.5 million and $2.6 million for the years ended 31 December 2015 and 31 December 2016 respectively.

With a higher oil price assumed (2017: $61/bbl, 2018: $67/bbl, 2019 and 2020: $75/bbl, 2021 onwards: $81/bbl), the net asset value increases by $51.9 million and $141.2 million for the years ended 31 December 2015 and 31 December 2016 respectively.

Retaining the base oil price of $55/bbl, if the discount rate is changed to 12.65 per cent. and 15.4 per cent. for the years ended 31 December 2015 and 31 December 2016 respectively, then the net asset value decreases by $22 million and $22.7 million for the years ended 31 December 2015 and 31 December 2016 respectively.

Retaining the base oil price of $55/bbl, if the discount rate is changed to 10.35 per cent. and 12.6 per cent. for the years ended 31 December 2015 and 31 December 2016 respectively, then the net asset value increases by $25.4 million and $24.4 million for the years ended 31 December 2015 and 31 December 2016 respectively.

No sensitivity testing has been performed for 2017 as the impairment made is considered to be a final settlement position.

b) South-east Impairment Testing (Midstream Assets, Uquo and Stubb Creek)

The assets which form part of the Agreed Transaction are included within this segment. As at 30 June 2017, the Net Book Value of these assets are: Stubb Creek $26 million, Uquo $228 million and Accugas $398 million.

In order to align the Seven Group's accounting policies with those of Savannah, impairment testing was re-performed using Savannah's own reserve estimations for the South-east region. In calculating these impairments, a discount rate of 10 per cent. was used for the year ended 31 December 2014. This discount rates is the same as that used by the Seven Group in their original impairment testing. The oil price per barrel was taken as $55.00 for each year from 2017 onwards. These assumptions constitute the 'base case'.

Impairment testing on the base case in 2014 resulted in a $105.7 million impairment against the Stubb Creek and Uquo operating assets and a $440.5 million impairment against infrastructure assets. The carrying amounts of these assets at the end of 2014 therefore equals their recoverable amounts. Impairment testing was performed from 2015 to 2017 and it was concluded that no impairment was necessary.

Different scenarios were simulated to consider the sensitivity of impairments to changes in the base case assumptions.

With a lower oil price assumed (2017: $48/bbl, 2018: $50/bbl, 2019 onwards: $52/bbl), the net asset value reduces by $5.7 million for the year ended 31 December 2014.

With a higher oil price assumed (2017: $61/bbl, 2018: $67/bbl, 2019 and 2020: $75/bbl, 2021 onwards: $81/bbl), the net asset value increases by $39.4 million for the year ended 31 December 2014.

Retaining the base oil price of $55/bbl, if the discount rate is changed to 11 per cent. for the year ended 31 December 2014, then the net asset value decreases by $48.5 million.

Retaining the base oil price of $55/bbl, if the discount rate is changed to 9 per cent. for the year ended 31 December 2014, then the net asset value increases by $52.8 million.

18. Assets held for sale

As at 1 January 2014, the Seven Group had an asset held for sale of $7.3 million for its 49 per cent. participating interest in the Matsogo field. During the year ended 31 December 2014, the Seven Group completed the sale of its 49 per cent. participating interest in this field to its Joint Venture partner, Chorus Energy, for $7.0 million. The value of this has asset had been written down to its recoverable amount in 2013 and therefore there was no profit or loss recorded on the sale in 2014. In addition, the Seven Group transferred to inventory a surplus generator from its Uquo field's central processing facility to be used as spares to maintain its existing generators.

19. Trade and other receivables

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Trade receivables				
Receivables from sales	28,040	79,572	33,023	46,736
Amounts receivable from joint venture partners	325	4,945	6,949	10,331
Total trade receivables	28,365	84,517	39,972	57,067
Other receivables				
Deposits	602	456	420	386
VAT receivables	2,453	3,811	7,034	8,332
Other receivables	7,262	19,729	13,431	13,248
Rental prepayments	3,210	4,565	2,085	1,434
Other prepayments	4,381	5,937	8,580	5,021
Total trade and other receivables	46,273	119,015	71,522	85,488

The average credit period given on joint interest billings and oil and gas sales is 60 days (2016: 60 days, 2015: 60 days, 2014: 60 days).

The Seven Group does not currently charge interest on past due receivables although in the event receivables become past due the Seven Group can do so at rates specified in the various agreements. The Seven Group periodically reviews all receivables outstanding to assess their recoverability.

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Neither past due nor impaired	29,670	13,066	5,917	10,337
Past due 1-30 days	–	10,281	7,519	13,171
Past due 31-90 days	61	30,641	9,439	13,124
Past due 90+ days	4,063	23,281	34,683	36,625
	33,794	77,269	57,558	73,257

2014 and 2015 provisions made within other receivables relate to past withholding taxes refundable from Nigerian vendors, historic payroll taxes and amounts owed from joint venture partners. No other trade receivable balances were impaired, including balances past 90 days due, as the Seven Directors believed the amounts to be recoverable based on the progress of discussions with its customers on resolving these outstanding amounts.

2016 provisions made within other receivables relate to historical amounts recoverable from joint venture partners. No other trade receivable balances were impaired, including balances past 90 days due, as the Seven Directors believed the amounts to be recoverable based on the progress of discussions with its customers on resolving these outstanding amounts. This position remained unchanged at 30 June 2017.

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Provisions against receivables				
Opening balance	(1,895)	(2,043)	(2,642)	(3,051)
Provided during the year	(538)	(1,100)	(1,546)	–
Utilisation of provision	390	501	1,137	–
Closing balance	(2,043)	(2,642)	(3,051)	(3,051)

Further detail on non-current other receivables is as below:

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Non-current other receivables				
Other receivables	–	1,445	–	–
Debt service reserve account for Seven Group borrowings	5,827	4,956	–	–
Stamp duty escrow reserve for Seven Group borrowings	2,440	2,240	1,442	1,342
Other cash restricted balances (note 21)	–	–	2,001	2,001
Total non-current other receivables	8,267	8,641	3,443	3,343

The debt service reserve account for Seven Group borrowings was released during 2016 when Accugas Limited entered into a $50.0 million debt service guarantee facility, further detailed in note 24 (i) to these consolidated financial statements.

The Savannah Directors consider that the carrying amount of trade and other receivables is approximately equal to their fair value.

20. Inventories

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Underlift	285,057	221,536	291,333	194,151
Hydrocarbon inventories	135	2,067	1,618	833
Spare parts	6,204	5,385	2,373	2,426
Total inventories	291,396	228,988	295,324	197,410

The underlift mainly includes the Seven Group's share of unsold production entitlement under the SAA.

In 2017, the Seven Group impaired a portion of its underlift inventory to its net realisable value as part of the impairment of the expenditures related to the notice of termination received from NPDC (see the SAA section under note 4 "critical accounting judgements and key sources of estimation uncertainty" and note 17). This resulted in a "change in underlift" charge of $97 million.

21. Cash and Cash Equivalents

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Held in Nigerian banks	26,250	27,768	11,272	12,824
Held in banks outside Nigeria	12,204	2,705	1,532	1,326
Cash and cash equivalents	38,454	30,473	12,804	14,150
Restricted cash balances	8,272	7,219	3,459	3,357
Total cash balances	46,726	37,692	16,263	17,507
Presented as:				
Restricted cash: in non-current other receivables (note 19)	8,267	7,196	3,443	3,343
Restricted cash: in trade and other receivables	5	23	16	14
Cash and cash equivalents	38,454	30,473	12,804	14,150
Total cash balances	46,726	37,692	16,263	17,507

Cash and cash equivalents comprise cash and short-term bank deposits with an original maturity of three months or less. Restricted cash balances include deposits, stamp duty and debt service reserve amounts required to be held relating to the Group's borrowings. The carrying amount of these assets is approximately equal to their fair value.

Cash being assumed by Savannah is expected to include all cash in the entities within the parameter of the Agreed Transaction.

22. Trade and other payables

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Trade payables	28,052	51,474	36,653	32,070
Accruals	491,185	68,878	77,512	56,688
Amounts owed under the Strategic Alliance Agreement	–	416,971	354,286	361,222
Amounts owed to joint operation partners	–	4,752	287	2,907
Other payables	55,861	9,135	9,780	13,421
PAYE and social security	1004	1,860	430	431
WHT and VAT payable	16,858	18,858	16,841	17,580
Interest payable	10,739	13,127	12,392	58,903
Total trade and other payables	603,699	585,055	508,181	543,222

Trade payables and accruals principally comprise amounts outstanding to the Seven Group's joint venture partners for capital expenditures, ongoing operational and corporate costs and amounts cash called or accrued under the SAA. The increase in accruals during 2014 included costs associated with the Strategic Alliance Agreement, which were initially unapproved by NPDC with the operator, but which were approved on subsequent review in 2015.

The increase in interest payable to $58.9 million in 2017 is due to the Seven Group not servicing the majority of its debt during the first half of 2017 (see note 24).

The average credit period taken for trade purchases is 289 days (2016: 135 days, 2015: 53 days, 2014: 40 days). For most suppliers, no interest is charged on the trade payables for the first 30 days from the date of the invoice. The Group has working capital risk management policies in place to ensure that all payables are paid within the agreed credit terms where possible and can increase due to liquidity pressures (see note 25). Savannah Management consider that the carrying amount of trade and other payables approximates to their fair value.

23. Deferred tax

The following are the major deferred tax assets/(liabilities) recognised by the Seven Group and movements thereon during the current and prior year:

	Fixed assets $000	*Unrealised FX (gains)/ losses $000*	*Share-based payments $000*	*Tax losses $000*	*Strategic alliance agreement $000*	*Other provisions $000*	*Capitalised interest $000*	*Total $000*
At 1 January 2014	(16,463)	707	2,210	19,308	(77,899)	568	(917)	(72,486)
Adjustments in respect of prior years	1,252	–	1,835	726	(7,617)	2	(2)	(3,804)
Acquisitions	(39,265)	–	–	8,268	–	–	–	(30,997)
Credit/(expense) to income	275,820	(3,486)	1,197	4,514	(95,203)	–	(360)	182,482
At 31 December 2014	221,344	(2,779)	5,242	32,816	(180,719)	570	(1,279)	75,195
Adjustments in respect of prior years	(3,442)	933	255	713	(1,065)	876	(154)	(1,886)
Acquisitions	(11,413)	–	–	–	–	–	–	(11,413)
Credit/(expense) to income - current year	65,113	(2,020)	1,483	15,714	(12,393)	(205)	38	67,730
At 31 December 2015	271,602	(3,866)	6,980	49,241	(194,177)	1,241	(1,395)	129,626
Re-categorise SAA depletion	(89,994)	–	–	–	89,994	–	–	–
Adjustments in respect of prior years	718	–	(467)	217	–	1,758	(266)	1,961
Credit/(expense) to income statement - current year	32,300	(8,217)	657	32,443	39,445	(2,007)	(990)	93,631
At 31 December 2016	214,626	(12,083)	7,169	81,903	(64,738)	992	(153)	225,218
Adjustments in respect of prior years	–	–	–	–	–	–	–	–
Credit/(expense) to income	(7,553)	(1,006)	(6,687)	(23,142)	64,738	(647)	2,651	28,354
At 30 June 2017	207,073	(13,089)	482	58,761	–	345	–	253,572

Certain deferred tax assets and liabilities have been offset in line with the Enlarged Group's accounting policy (note 2). The following is the analysis of the deferred tax balances (after offset) for financial reporting purposes:

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Deferred tax liabilities	(124,916)	(103,580)	(29,625)	(6,721)
Deferred tax assets	200,111	233,206	254,853	260,293
Total net deferred tax liabilities	75,195	129,626	225,218	253,572

At 30 June 2017, the Group has unused tax losses of $541.7 million (2016: $457.3 million, 2015: $382.2 million, $302.7 million) available for offset against future profits. A deferred tax asset has only been recognised where future utilisation of such losses is considered probable. A deferred tax asset has been recognised on gross losses of $155.8 million (2016: $235.1 million, 2015: $126.8 million, 2014: $88.8 million) on the basis of the Group's forecast results for each entity. No deferred tax asset has been recognised in respect of the remaining $385.9 million (2016: $222.2 million, 2015: $255.4 million, 2014: $213.9 million) of losses. Included in unrecognised tax losses are losses of $3.8 million (2016: $3.8 million, 2015: $1.6 million, 2014: $0.2 million) which will expire in 2018-2023. Other losses will be carried forward indefinitely.

The following deferred tax assets in entities which made a loss during the current or preceding year have been recognised on the basis of the Seven Group's forecasted results for each entity:

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Tax Losses	17,596	28,234	54,723	58,761
Fixed assets	184,286	207,729	211,544	213,793
Unrealised foreign exchange gain	(2,850)	(4,203)	(11,918)	(13,089)
Share based payments	509	484	483	483
Other provisions	570	962	11	345
Total deferred tax assets	200,111	233,206	254,853	260.293

As part of the Agreed Transaction, the overall deferred tax assets and liabilities being acquired are: UERL $67.7 million Asset, Accugas: $188.1 million Asset, Uquo: $6.7 million Liability.

24. Borrowings

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Secured borrowing at amortised cost				
Bank loans (i)				
– Loans from non-related parties	389,115	433,407	404,466	400,515
Other loans (ii)				
– Loans from non-related parties	350,000	401,810	432,819	432,319
– Loans from related parties (note 35)	50,000	50,000	53,038	53,038
Unsecured borrowing at amortised cost (iii)				
– Loans from non-related parties	11,056	6,000	–	–
– Loans from related parties (note 35)	8,533	7,800	5,023	4,674
Total gross borrowings	808,704	899,017	895,346	890,546
Unamortised finance costs incurred on raising debt	(42,612)	(53,546)	(59,365)	(51,696)
Total borrowings (net of unamortised finance costs)	766,092	845,471	835,981	838,850
Analysed as:				
Current borrowings	112,510	424,653	400,829	838,850
Non-current borrowings	653,582	420,818	435,152	–
Total borrowings	766,092	845,471	835,981	838,850

The borrowings of the Seven Group are to be substantially restructured as part of the Agreed Transaction. The terms of the debt restructuring are as per the Lock-up Agreement and are to be restructured in entirety.

The Seven Group has provided security in respect of certain of these borrowings in the form of share pledges, as well as fixed and floating charges over assets of the Seven Group. Share pledges are over a number of entities in the Seven Group and are either: in favour of Pari Debt (see definition below) and the Liquidity Facility, or in favour of Accugas Lenders. There are also securities in place over assets and bank accounts across Seven Group entities in Nigerian, British, Jersey and Mauritian jurisdictions.

Pari Debt includes the following:

(a) 10.25 per cent. Senior Secured Notes
(b) 10.50 per cent. Senior Secured Notes
(c) Senior Secured Term Loan Facility I
(d) Senior Secured Term Loan Facility II
(e) Working Capital Facility
(f) Promissory Note

The contractual maturity profile of the Seven Group's gross borrowings, including future interest expense on an undiscounted basis, is shown in the table below. This differs from both the carrying value and the fair value due to the effect of discounting, future interest costs and unamortised finance fees. Interest expense on floating rate debt is based on the Seven Group's best estimate of the LIBOR and NIBOR rates.

	Year ended 31 December 2014	Year ended 31 December 2015	Year ended 31 December 2016	Six months ended 30 June 2017
Current				
Amount due within one year	171,138	166,259	107,336	327,780
Amount due after one year but within two years	15,058	125,951	243,812	291,911
Amount due after five years but within five years	4,016	323,292	167,567	636,341
Non-current				
Amount due within one year	125,774	49,237	57,681	2,599
Amount due after one year but within two years	401,908	183,606	709,369	26,303
Amount due after five years but within five years	482,500	441,137	–	–
	1,200,394	1,289,482	1,285,765	1,284,934

(i) Bank loans

Bank loans are as follows:

Bank loans	*Year ended 31 December 2014 $ million*	*Year ended 31 December 2015 $ million*	*Year ended 31 December 2016 $ million*	*Six months ended 30 June 2017 $ million*
Accugas IV Facility	355	385	374.6	374.6
Debt Service Guarantee Facility	–	–	11.3	11.3
Bank of Industry Loan Facility	34.1	18.2	2.7	–
Naira Working Capital Facility (USD Equivalent)	–	30.2	15.9	14.6
Total	389.1	433.4	404.5	400.5

Accugas IV Facility

The Seven Group has a $445.0 million facility, of which the outstanding principal at 30 June 2017 was $374.6 million (2016: $374.6 million, 2015: $385.0 million, 2014: $355.0 million). The facility bears interest at US LIBOR plus 10.0 per cent. per annum and is repayable in quarterly instalments from 31 March 2016 to 30 September 2019. Due to Seven Group liquidity constraints the interest payment of $10.4 million and the principal payment of $1.0 million due on 31 March 2017, and the interest payment of $10.5 million and the principal payment of $1.0 million due on 30 June 2017 were not paid. In addition, as at 30 June 2017, as a result of a delay in finalisation of ancillary documentation in relation to the World Bank Partial Risk Guarantee (PRG), Accugas Limited had not fully complied with certain of the conditions subsequent. Therefore, Accugas Limited was not in compliance with its loan obligations and therefore the long-term balance of the outstanding loan has been disclosed within current borrowings.

Debt Service Guarantee Facility

As at 30 June 2017, the Seven Group had an outstanding principal of $11.3 million (2016: $11.3 million, 2015: nil, 2014: nil). On 29 December 2016, Accugas Limited entered into a $50.0 million debt service guarantee facility ("DSG Facility") with GuarantCo Limited. In the event of liquidity constraints the DSG Facility enables Accugas to meet up to $50 million of its debt service obligations in respect of the Accugas IV facility. The DSG Facility also eliminates the requirement under the Accugas IV facility to maintain a debt service reserve account thereby releasing approximately $5.0 million previously held. With the consent of GuarantCo and the Accugas IV facility lenders, Accugas Limited drew down $11.3 million immediately available under the DSG Facility in order to make the interest and principal repayment due on the Accugas IV Facility on 31 December 2016. Due to Seven Group liquidity constraints the interest of $0.2 million and standby fees for undrawn amounts of $0.1 million due on 30 June 2017 were not paid. As a result of this, and Accugas Limited's non-compliance with the Accugas IV facility loan obligations, a cross default with the DSG Facility has resulted and all principal amounts owed at 30 June 2017 have been disclosed within current borrowings.

Bank of Industry Loan Facility

At 30 June 2017, the Seven Group had fully repaid its Naira denominated Bank of Industry Loan Facility, held by the Seven Group's subsidiary EHGC (2016: $2.7 million, 2015: $18.2 million, 2014: $34.1 million). At the time of acquisition, and continuing to 31 December 2015, EHGC was not in compliance with certain financial covenants under the provisions of the facility. As a consequence, from 2014, the Bank of Industry Loan Facility has been disclosed in current borrowings.

Naira Working Capital Facility

The Seven Group has a four-year, 6.0 Billion Naira denominated working capital facility with FBN Merchant Bank. As at 30 June 2017, the Seven Group has 4.8 Billion Naira drawn down on the facility, a USD equivalent amount of $14.6 million (2016: $15.9 million, 2015: $30.2 million, 2014: nil). The facility bears interest at NIBOR plus 4 per cent. per annum and requires a mandatory full repayment of outstanding principal annually until 2019. As a result of Accugas Limited's non-compliance with the Accugas IV facility loan obligations, a cross default with the working capital facility has resulted and all principal amounts owed at 30 June 2017 have been disclosed within current borrowings.

Reserves Based Lending Facility

During 2014, the Seven Group had a $350.0 million Reserve Based Lending Facility with three banks (one of which was Standard Chartered Bank, a related party of the Seven Group). The outstanding Reserve Based Lending Facility principal amount of $200.3 million was fully repaid on 10 October 2014.

Working Capital Facility

During 2014, the Seven Group had a $40.0 million Working Capital Facility with First City Monument Bank plc for general funding requirements. The $25.0 million principal amount outstanding was fully repaid on 10 October 2014.

(ii) Other loans

10.25 per cent. Senior secured loan notes

The Seven Group has 10.25 per cent. Senior secured loan notes listed on the Irish Stock Exchange. The total principal outstanding at 30 June 2017 was $318.0 million (2016: $318.0 million, 2015: $300.0 million, 2014: $300.0 million). $50.0 million of loan notes were issued to the International Finance Corporation, a security holder and related party of the Seven Group. The notes, issued at a discount, mature in 2021 and have a fixed coupon of 10.25 per cent., paid semi-annually.

10.50 per cent. Senior secured loan notes

The Seven Group has a 10.50 per cent. Senior secured loan note issued to the Nigeria Sovereign Investment Authority. The total principal outstanding at 30 June 2017 was $106.5 million (2016: $106.5 million, 2015: $100.0 million, 2014: $100.0 million). The Bond, issued at par, matures in 2021 and has a fixed coupon of 10.5 per cent., paid semi-annually.

On 11 October 2016, Seven Energy Finance Limited (the "Issuer", a subsidiary of Seven) announced agreement on the terms of an amendment of the 10.50 per cent. Senior Secured Notes and 10.25 per cent. Senior Secured Notes (together, the "Notes"). The main terms of the amendment to the Notes ("Notes Amendments") include:

(i) the automatic capitalisation of the interest payments due under the Notes on 11 October 2016 ("initial PIK Interest Payment");

(ii) an ability for the Issuer, provided that certain operational covenants have been satisfied, to elect that interest payments due under the Notes on 11 April 2017 and 11 October 2017 are capitalised; and

(iii) an ability for the Issuer, provided that certain operational covenants have been satisfied and that the Company has raised at least $50.0 million of equity on or prior to 11 April 2018, to elect that the interest payment due under the Notes on 11 April 2018 is capitalised, collectively (i) to (iii) "PIK Interest Payments".

On 1 December 2016, the Notes Amendments were successfully executed. In addition to consenting holders receiving the initial PIK Interest payments, certain consent payments were made to consenting holders. PIK Interest Payments that are capitalised will accrue interest as follows:

(i) Interest period ending 11 April 2017 – 3.0 per cent. p.a. higher than the coupon rate;
(ii) Interest period ending 11 October 2017 – 3.5 per cent. p.a. higher than the coupon rate; and
(iii) Interest period ending 11 April 2018 – 3.5 per cent. p.a. higher than the coupon rate.

The Seven Group did not satisfy the operational covenants required in order to be able to capitalise the interest on the Notes, and as a result of Seven Group liquidity constraints, was also not able to service the interest due of $21.9 million due on 11 April 2017. All principal amounts owed at 30 June 2017 have been disclosed within current borrowings.

Senior secured term loans

On 23 June 2015, the Seven Group entered into two new senior secured term loan facilities which are *pari passu* with the Senior Secured Loan Notes and Private Bond, and have similar covenant requirements. The use of the proceeds are for general corporate purposes and working capital funding. These facilities are described below:

Senior Secured Term Loan Facility I – $25.0 million loan commitment for a term of four and a half years, with an option to extend for a further 18 months, subject to further approval. The repayment of any outstanding balance is due at the end of December 2019. During the term, amounts can be redrawn or repaid at any time. Interest accrues on the principal at US LIBOR plus 10.25 per cent. per annum and is payable quarterly. As at 30 June 2017 $25.0 million (2016: $25.0 million, 2015: $25.0 million, 2014: nil) was outstanding.

As a result of Seven Group liquidity constraints, the interest due of $0.7 million on 30 June 2017 was not paid.

Senior Secured Term Loan Facility II – $26.8 million loan commitment with a term of five years. Loan amortisation commences annually from December 2016 at approximately 10.0 per cent. of the total commitment until 2019, with the remaining balance due by June 2020. Interest accrues on the principal at US LIBOR plus 10.25 per cent. per annum for the first 18 months, increasing by 0.5 per cent. per annum every six months thereafter. Interest is payable semi-annually. As at 30 June 2017 $24.1 million (2016: $26.8 million, 2015: $26.8 million, 2014: nil) was outstanding.

As a result of Seven Group liquidity constraints interest due of $1.3 million on 30 June 2017 was not paid meaning the Seven Group did not comply with the terms of the loan and subsequently the outstanding principal amount is disclosed within current borrowings.

As a result of non-payment of interest due on 11th May 2017 for the Senior Secured Notes and the 10.50 per cent. Notes, two pari passu senior secured terms loans, the $25.0 million Senior Secured Loan Facility I and $26.8 million Senior Secured Loan Facility II, have become in default since that time.

Loans from non-related parties

The Seven Group has an $11.5 million promissory note (2016: $12.0 million, 2015: $6.0 million, 2014: $12.0 million) issued as part consideration for the acquisition of Afren Global Energy Resources Limited in 2014. The initial note was interest bearing at US LIBOR plus 10.0 per cent. per annum (payable semi-annually) and was repayable on 12 June 2016.

The revised terms of the note include interest payable at 3-month US LIBOR plus 11.25 per cent. per annum (payable quarterly in arrears), and repayable within 12 months from the date of the further drawdown: $6.0 million payable six months from the date of the of the further drawdown and thereafter six monthly repayments of $1.0 million each. In January 2017, the note holder agreed to further amend the repayment profile such that $6.0 million would be payable by July 2017 and the balance by January 2018.

$0.5 million was repaid on 16 February 2017, however due to Seven Group liquidity constraints no further principal repayments have been made including interest due of $0.4 million on 18 April 2017 has not been paid. The loan is now classified as current.

(iii) Unsecured borrowings at amortised cost

Loans from related parties

The Seven Group, through its subsidiary Universal Energy, holds a Naira denominated loan due to Akwa Ibom Investment (a Nigerian State Company which promotes industrialisation of the Akwa Ibom State) and Industrial Promotion Council (a minority shareholder in Universal Energy) for $4.7 million (2016: $5.0 million, 2015: $7.8 million, 2014: $8.5 million). Principal repayments were to commence from September 2013 in semi-annual instalments, together with interest payments from commencement of first oil production at 15.0 per cent. per annum. Due to the delays in the commencement of oil production, as at 30 June 2017, Universal Energy had failed to make any of the payments due and, therefore, was not in compliance with the loan agreement. As a consequence, the loan has been disclosed within current borrowings. Universal Energy's management are in discussion with the lender to reschedule the repayment and interest schedule.

Weighted average interest rate

The weighted average effective interest rates charged on borrowings during the period were as follows:

	Year ended 31 December 2014 $ million %	*Year ended 31 December 2015 $ million %*	*Year ended 31 December 2016 $ million %*	*Six months ended 30 June 2017 $ million %*
Weighted average effective interest rate	12.81	11.78	12.56	13.13

25. Financial Instruments

Categories of financial instruments

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Financial assets				
Cash and cash equivalents (note 21)	38,454	30,473	12,804	14,150
Loans and receivables	44,497	113,342	55,265	74,044
Total	82,951	143,815	68,069	88,194
Financial liabilities				
Held at amortised cost				
Trade and other payables	281,994	436,803	413,398	468,524
Borrowings (note 24)	766,092	845,471	835,981	838,850
Total	1,048,086	1,282,274	1,249,379	1,307,374

The combined fair values of the Senior secured loan notes at 30 June 2017 was $123.6 million (2016: $169.8 million, 2015: $204.0 million, 2014: $363.3 million). This is a level one valuation and is taken from quoted bond market rates.

Significant accounting policies

Details of the significant accounting policies and methods adopted, including the criteria for recognition, the basis of measurement and the basis on which income and expenses are recognised, in respect of each class of financial asset, financial liability and equity instrument are disclosed in note 2 to the Financial Statements.

Capital risk management

The Seven Group manages its capital, including ongoing monitoring and adherence to covenants and indebtedness obligations of its borrowings to ensure that entities in the Seven Group will be able to continue as going concerns while maximising the returns to stakeholders. Due to recent liquidity pressures faced, the Seven Group has been unable to meet its debt obligations and adherence to its covenants as discussed in further detail in note 24.

The capital structure of the Seven Group currently consists of net debt, which includes the borrowings and cash and cash equivalents, and equity which consists of irredeemable convertible loan notes and ordinary share capital. The irredeemable convertible loan notes are categorised as equity due to the terms of these instruments.

Financial risk management objectives

The Seven Group's Finance function coordinates access to international financial markets and monitors and manages the financial risks relating to the operations of the Seven Group. These risks include commodity price risk, currency risk, credit risk, interest rate risk and liquidity risk.

Commodity price risk

The Seven Group's activities expose it primarily to the financial risks of changes in oil and gas commodity prices. The Seven Group monitors and manages this risk where considered appropriate and possible through long-term sales contracts.

The Seven Group has exposure to changes in the oil price; however, this is mitigated to an extent as, under the terms of the Strategic Alliance Agreement, the Group recovers its cost oil in absolute US Dollar terms. Changes in the oil price only affects the timing of cost recovery, the number of barrels lifted, and the value of any residual profit oil.

The Seven Group has a number of gas sales agreements (refer to note 5 for the number of such agreements in place) of up to twenty years that contain long term fixed gas prices with annual inflation adjustments. As a result, changes in any market gas price over the duration of each agreement would have no impact on the Seven Group's result and equity in the current or future periods.

Foreign currency risk management and sensitivity analysis

The Seven Group operates internationally and has exposure to currency risk on purchases, sales, cash and cash equivalents that are denominated in currencies other than US Dollars. The currencies giving rise to this are principally the British Pound Sterling and Nigerian Naira. The Seven Group's exposure to foreign exchange fluctuations is reduced by maintaining cash balances primarily in US Dollars reflecting the currency of the majority of the Group's transactions, and where possible, the Seven Group seeks to settle non-US Dollar denominated liabilities in the same currency as other cash inflows, therefore providing a natural hedge against currency fluctuations.

The carrying amount of the Seven Group's foreign currency denominated monetary assets and monetary liabilities at the reporting date are as follows:

	Liabilities			
	Dec 2014	*Dec 2015*	*Dec 2016*	*June 2017*
	$000	*$000*	*$000*	*$000*
British Pound Sterling	(4,049)	(2,627)	(3,026)	(2,499)
Nigerian Naira	(87,446)	(110,790)	(60,415)	(34,204)

	Assets			
	Dec 2014	*Dec 2015*	*Dec 2016*	*June 2017*
	$000	*$000*	*$000*	*$000*
British Pound Sterling	4,934	2,327	1,458	1,375
Nigerian Naira	13,240	21,511	8,605	16,094

	Net assets/(liabilities)			
	Dec 2014	*Dec 2015*	*Dec 2016*	*June 2017*
	$000	*$000*	*$000*	*$000*
British Pound Sterling	885	(299)	(1,568)	(1,124)
Nigerian Naira	(74,206)	(97,097)	(51,810)	(18,110)

For 2017, a 20 per cent. increase and decrease in the US Dollar against the Sterling currency would have resulted in a decrease in loss and an increase in equity of $0.2 million and increased loss and decreased equity of $0.3 million, respectively. For 2016, a 20 per cent. increase and decrease in the US Dollar against the Sterling currency would have resulted in an increase in profit and equity of less than $0.3 million and a decrease of less than $0.3 million, respectively.

For 2017, a 20 per cent. increase and decrease in the US Dollar against the Naira currency would have resulted in a decrease in loss and increase in equity of $4.5 million and an increase in loss and decrease in equity $3.0 million respectively. For 2016, a 20 per cent. increase and decrease in the US Dollar against the Naira currency would have resulted in an increase in profit and equity of $8.7 million and a decrease of $12.9 million, respectively.

For 2015, a 20 per cent. increase and decrease in the US Dollar against the Sterling currency would have resulted in a decrease in loss and an increase in equity of less than $0.1 million and increased loss and decreased equity of less than $0.1 million, respectively. For 2014, a 20 per cent. increase and decrease in the US Dollar against the Sterling currency would have resulted in an increase in profit and equity of $0.2 million and a decrease of $0.2 million, respectively.

For 2015, a 20 per cent. increase and decrease in the US Dollar against the Naira currency would have resulted in a decrease in loss and increase in equity of $18.9 million and an increase in loss and decrease in equity of $20.1 million respectively. For 2014, a 20 per cent. increase and decrease in the US Dollar against the Naira currency would have resulted in an increase in profit and equity of $13.4 million and a decrease of $17.0 million, respectively.

Credit risk management

Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Seven Group. The Seven Group has a policy of only dealing with creditworthy counterparties and obtaining sufficient collateral or advance payment where appropriate, as a means of mitigating the risk of financial loss from defaults.

Exposure to credit risk in the periods shown is considered to be mitigated to an extent because the bulk of cash inflows from sales are from an international super-major (associated with the Strategic Alliance Agreement with a Nigerian national oil company subsidiary) or from Nigerian state-owned power companies. Other funding sources are considered to be from reputable and international banking institutions and security holders.

Further dilution of credit risk is expected to occur in the future in relation to the sale of oil and gas in Nigeria as the Seven Group's gas operations expand and the customer base diversifies. The Seven Group will look to further mitigate this risk by obtaining letters of credit or bank guarantees where appropriate to support payment where possible.

The carrying amount of financial assets recorded in the Financial Statements, which is net of impairment losses, represents the Seven Group's maximum exposure to credit risk as no collateral or other credit enhancements are held.

Interest rate risk management and sensitivity analysis

The Seven Group is exposed to interest rate risk because entities in the Seven Group borrow funds at both fixed and floating interest rates. The risk is managed by the Seven Group maintaining an appropriate mix between fixed and floating borrowings and floating rates are typically based on stable indices (eg LIBOR).

The sensitivity analyses below have been determined for floating rate liabilities based on the exposure to interest rates at the balance sheet date. For floating rate liabilities, the analysis is prepared based on the weighted average liability outstanding during the year.

If interest rates had been 0.5 per cent. higher or lower, and all other variables were held constant, the Seven Group's gross interest costs (before any interest capitalisation adjustment) for the period ended 30 June 2017 would have increased or decreased respectively by $1.0 million (2016: $2.1 million, 2015: $1.9 million, 2014: $2.4 million). This is attributable to the Seven Group's exposure to interest rates on its variable rate borrowings.

The Seven Group had cash and cash equivalents on hand on which it earned investment income. A 0.5 per cent. increase or decrease in the interest rate would not have resulted in a material increase or decrease in investment (2016: $0.1 million, 2015: $0.2 million, 2014: $0.2 million).

Liquidity risk management

Ultimate responsibility for liquidity risk management has historically rested with the Seven Board of Directors, which has built an appropriate liquidity risk management framework for the management of the Seven Group's short, medium and long-term funding and liquidity management requirements. The Savannah Board will assume this responsibility going forward. The Seven Group maintains adequate liquid reserves, by continuously monitoring forecast and actual cash flows and matching the maturity profiles of financial assets and liabilities.

The Seven Group closely monitors and manages its liquidity risk. Cash forecasts are regularly produced and sensitivities run for different scenarios including, but not limited to, changes in commodity prices, different production rates from the Seven Group's portfolio of producing fields and delays in development projects. In addition, the Seven Group regularly monitors its utilised and unutilised amounts of its borrowings in place (further details of which are provided in note 24). Refer to note 21 for the respective locations of the Seven Group's cash reserves. All of the Seven Group's cash and cash equivalents are currently held within reputable and well known commercial institutions.

Despite the measures described above the Seven Group has faced significant external liquidity pressures including the loss of revenue from the OMLs, operational delays and liquidity issues in the domestic power sector, to which the Seven Group has significant exposure, and the restricted ability to convert local currency into US dollars. This has led to a deterioration in Seven Group's liquidity position.

The following table details the Seven Group's remaining contractual maturity for its non-derivative financial liabilities (excluding borrowings, the repayment terms of which are provided in note 24). The amounts are based on undiscounted cash flows and on the earliest date on which the Seven Group can be required to pay.

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Less than 30 days	271,255	425,710	354,286	361,222
31-60 days	–	–	49,445	97,475
61-90 days	1,472	662	–	–
91+ days	9,267	10,431	9,667	9,827
Total	281,994	436,803	413,398	468,524

26. Provisions

	Decommissioning Provision $000
Balance at 1 January 2014	26,045
Provided during the year	22,596
Unwinding of the discount (note 13)	1,118
Balance at 31 December 2014	49,759
Provided during the year	1,518
Released during the year	(3,098)
Unwinding of the discount (note 13)	2,766
Balance at 31 December 2015	50,945
Provided during the year	–
Change in estimate	(10,578)
Unwinding of the discount (note 13)	2,165
Balance at 31 December 2016	42,532
Provided during the year	–
Change in estimate	2,541
Unwinding of the discount (note 13)	1,024
Balance at 30 June 2017	46,097

The Seven Group provides for the present value of estimated future decommissioning costs for certain of its oil and gas properties in Nigeria. The amounts shown are expected to be settled between 2028 and 2040. Further detail on the derivation of the decommissioning provision can be found under note 4. No decommissioning liability is recognised for the SAA as the Seven Group has no contractual liability to decommission the license. Decommissioning provisions are in relation to the assets being acquired, including Accugas in which Savannah will have a 20 per cent. interest

27. Capital commitments and other contingencies

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Minimum lease payments under operating leases recognised as an expense in the period	3,308	2,656	1,274	1,011

At the balance sheet date, the Seven Group had outstanding commitments for future minimum lease payments under non-cancellable operating leases, which fall due as follows:

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Within one year	644	882	727	727
In the second to fifth years inclusive	2350	2407	1272	908
Total	2,994	3,289	1,999	1,635

Operating lease payments represent rentals payable by the Seven Group for certain of its office and staff housing properties. Leases are typically negotiated for terms of one to five years. Leases in Nigeria are typically fully paid in advance. The lease relating to the Seven Group's offices in London is expected to be terminated as part of the Agreed Transaction.

Capital commitments

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Oil and gas assets – development	59,377	25,790	210	210
Oil and gas assets – exploration and evaluation	3,205	–	–	–
Total	62,582	25,790	210	210

Contingent liabilities

As at 30 June 2017, the Seven Group had contingent liabilities of $28.0 million (2016: $28.0 million, 2015: $28.0 million, 2014: $nil) in respect of a guarantee to a third party in relation to committed work programmes under certain of its upstream licence interests. This contingent liability relates to a parent company guarantee provided by SEIL for a performance bond, and is not to be acquired as part of the Agreed Transaction.

Pertaining to 2014 and 2015, commitments for development of oil and gas assets relate primarily to the contractually committed amounts for the construction of the Oron to Creek Town pipeline due to be completed in 2016. The construction contract contained a termination clause that can be exercised by the Group with 15 days' notice with commitment only to reimburse for the value of work performed.

28. Retirement benefit schemes

Defined contribution schemes

The Seven Group operates defined contribution retirement benefit schemes for all qualifying employees. The assets of the schemes are held separately from those of the Seven Group in funds under the control of trustees.

The employees of the Seven Group's subsidiaries in Nigeria are members of a state-managed retirement benefit scheme operated by the Government of Nigeria. The subsidiaries are required to contribute a specified percentage of payroll costs to the retirement benefit scheme to fund the benefits. The only obligation of the Seven Group with respect to the retirement benefit scheme is to make the specified contributions.

The total cost charged to income of $0.6 million (HY 2016: $1.1 million, FY 2016: $1.7 million, 2015: $2.3 million, 2014: $2.0 million) represents contributions payable to these schemes by the Group at rates specified in the rules of the plans. Contributions of $0.1 million (2016: $0.1 million, 2015: $0.4 million, 2014: $0.2 million) were due in respect of the half year ended 30 June 2017 had not been paid over to the schemes and are recorded within Trade and other payables.

29. Deferred revenue

The deferred revenue balance at 30 June 2017 of $64.0 million (2016: $62.2 million; 2015: $79.3 million; 2014: $46.8 million) represents the excess of cumulative take-or-pay invoices issued since first gas production commenced in 2014, over and above the total gas volumes delivered (and recognised within revenue from January 2014 to June 2017). This deferred revenue relates to gas sales from the Seven Group's infrastructure assets. Deferred revenue is split between current and non-current based on the expectation of when customers are expected to utilise gas which has been invoiced.

The current portion of deferred revenue is $7.6 million (2016: $nil, 2015; $nil, 2014, $12.2 million). The non-current portion of deferred revenue is $56.4 million (2016: $62.2 million, 2015: $79.3 million, 2014: $34.6 million).

30. Share capital

	Year ended 31 December 2014 $000	Year ended 31 December 2015 $000	Year ended 31 December 2016 $000	Six months ended 30 June 2017 $000
Issued and fully paid:				
514,243 ordinary shares of $0.01 each	5	5	5	5

During the period, no new ordinary shares were issued (2016: nil, 2015: 2,668, 2014: 2,666).

31. Irredeemable convertible loan notes

The Seven Group has ICLNs in issue. The following ICLNs were issued from January 2014 to June 2017:

	ICLN Value $000	Conversion price per share $	Number of ordinary shares if converted
At 1 January 2014	612,583	n/a	2,198,670
ICLNs issued	288,000	250	1,151,997
Issuance Costs	(5,141)	n/a	–
At 31 December 2014	895,442	n/a	3,350,667
ICLNs issued	25,650	250	102,600
Issuance Costs	(183)	n/a	–
At 31 December 2015	920,909	n/a	3,453,267
ICLNs issued	100,000	200	500,001
Issuance Costs	(1,347)	n/a	–
At 31 December 2016	1,019,562	n/a	3,953,268
ICLNs issued	–	–	–
Issuance Costs from prior year ICLN issuance	–	n/a	–
At 30 June 2017	1,019,562	n/a	3,953,268

The ICLNs are non-interest-bearing and are not repayable. They are convertible by the holder into ordinary shares of the Seven Group at any time between the date of issue of the notes and certain mandatory conversion trigger events (including an IPO) as per the irredeemable convertible loan note agreements. The proceeds received, net of transaction costs, from the issue of these irredeemable convertible loan notes have accordingly been included as a component of equity representing the fair value of the option to convert into ordinary shares of the Seven Group. None of the ICLNs issued to date have been converted to ordinary shares.

On 31 January 2014, as part of the consideration to acquire the entire issued share capital of SRL 905 Holdings Limited (renamed Seven Energy (Jersey) Limited), the Seven Group issued $33.0 million of ICLNs to Suntera Management Limited. The ICLNs are convertible into 132,000 shares at a conversion price of $250.00 per share.

In April 2014, the Seven Group signed Investment Agreements with three equity investors for a combined investment of $255.0 million. Each investment was in the form of a single ordinary share and the remainder in ICLNs at a conversion price of $250.00 per share. A total of three ordinary shares and 1,019,997 ICLNs have been issued. $146.0 million of the proceeds were received in May 2014, with the remaining $109.0 million received in October 2014 upon successful issuance of the Senior Secured Loan Notes.

On 27 February 2015, as part of the consideration to acquire the entire issued share capital of Gas Transmission and Power Limited, the Seven Group issued $25.7 million of ICLNs to the five individual shareholders of GTPL. The ICLNs are convertible into 102,600 shares at a conversion price of $250.00 per share.

On 16 February 2016, the Seven Group issued $100.0 million of ICLNs convertible into 500,001 shares at a conversion price of $200.00 per share.

Within the Investment Agreements referred to above, at 31 December 2016, there remains a price adjustment provision that within 24 months following the issue of ICLNs, should the Seven Group issue any new securities (except in a qualifying IPO) at a price (or with a conversion price) of less than $250.00 per share, the conversion price shall be deemed to be adjusted to such a lower price and further securities will be issued as a result.

This price adjustment provision represents an embedded debt arrangement within a host equity contract and accordingly the proceeds received are required to be split between equity and a derivative liability, with movements in the value of the latter recorded through the consolidated statement of comprehensive income until the relevant re-pricing provisions expire. At the inception of the Investment Agreements and the reporting date no liability has been recognised as it was considered to be immaterial.

As a result of the Agreed Transaction, the ICLNs are expected to convert into ordinary shares of Seven.

32. Equity reserves

	Other Equity Reserve $000	*Share-based payments reserve $000*	*Foreign Currency Translation Reserve $000*	*Total $000*
At 1 January 2014	16,176	23,940	(732)	39,384
Shared-based payments	–	4,150	–	4,150
Issuance of shares	–	(400)	–	(400)
Expiry of warrants	(1,396)	–	–	(1,396)
At 31 December 2014	14,780	27,690	(732)	41,738
Shared-based payments	–	4,987	–	4,987
Issuance of shares	–	(401)	–	(401)
At 31 December 2015	14,780	32,276	(732)	46,324
Shared-based payments	–	1,958	–	1,958
Purchase of treasury shares	(2,323)	–	–	(2,323)
At 31 December 2016	12,457	34,234	(732)	45,959
Shared-based payments	–	867	–	867
Purchase of treasury shares	–	–	–	–
At 30 June 2017	12,457	35,101	(732)	46,826

Other equity reserve: The other equity reserve is in respect of 148,571 (2016: 148,571, 2015: 148,571, 2014: 148,571) outstanding warrants previously issued at an exercise price of $350.00 per share and 11,400 treasury shares (2016: 11,400, 2015: nil, 2014: nil). The treasury shares of 11,400 represent the purchase during 2016 by a subsidiary of Seven Group shares. These shares are being held by the subsidiary until and employee benefit trust can be set up to hold them

Share-based payments reserve: The reserve represents cumulative amounts charged to the statement of comprehensive income in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

Foreign currency translation reserve: The foreign currency translation reserve is used to record exchange differences arising from the translation of the Financial Statements of foreign operations. The reserve was frozen from 1 January 2012 as the functional currency of the associated subsidiary (Seven Energy (UK) Limited) was changed from Sterling to US Dollars.

33. Share-based payments

The Seven Group has in place a share-based payment arrangement for its employees, has previously issued warrants to a contractor and has also issued share options in connection with the purchase of the Gulf of Guinea Energy Limited group of companies in 2009. In addition, in 2013, The Seven Group awarded fully paid up shares to a member of it's Executive Committee as part of his employment arrangements.

Discretionary Share Option Plan

The Seven Group operates a share option scheme for employees. The Seven Group's policy is to award options to eligible employees at the sole discretion of the HR & Remuneration Committee of the Seven Board. Options are issued at market price on the grant date and typically have a three-year vesting period, unless specifically amended. In addition, some options have performance related vesting conditions which require that the Seven share price reaches $700.00 per share before they are able to be exercised by the employee. The options expire up to seven years from the date of grant if they remain unexercised and are forfeited if the employee leaves the Seven Group before the options vest except at the discretion of the Seven Board. The share option plan going forward will be re-assessed by the Savannah Board.

The total share-based payment charge for the period was $0.9 million (HY2016: $1.1 million, FY2016: $2.0 million, FY2015: $5.0 million, FY2014: $4.2 million). The Seven Group granted no (2016: 26,260, 2015: 57,550, 2014: 47,550) share options to employees under the Discretionary Share Option Plan which will vest in one tranche on 30 June 2018 (2015: vest over three equal annual tranches from 1 January 2016, 2014: vest over three equal annual tranches from 1 January 2015).

Details of the share options outstanding during the year are as follows:

	Dec-14 Weighted average exercise price ($)	*Dec-14 Number of Share Options*	*Dec-15 Weighted average exercise price ($)*	*Dec-15 Number of Share Options*
Outstanding at beginning of year	309.18	156,059	295.44	200,040
Granted during the year	250.00	47,550	250.00	57,550
Forfeited during the year	291.07	(3,569)	264.60	(5,933)
Expired	–	–	299.35	(41,783)
Outstanding at the end of year	295.44	200,040	283.07	209,874
Exercisable at the end of year	308.59	128,124	305.15	119,420

	Dec-16 Weighted average exercise price ($)	*Dec-16 Number of Share Options*	*Jun-17 Weighted average exercise price ($)*	*Jun-17 Number of Share Options*
Outstanding at beginning of year	283.07	209,874	298.29	196,056
Granted during the year	–	26,260	–	–
Forfeited during the year	247.34	(16,477)	130.84	(10,750)
Expired	314.11	(23,600)	–	–
Outstanding at the end of year	244.42	196,057	214.66	185,306
Exercisable at the end of year	298.29	115,756	286.21	154,346

The weighted average remaining contractual life of the options outstanding at 30 June 2017 was 2.01 years (2016: 2.78 years, 2015: 3.92 years, 2014: 3.92 years). The range of exercise prices of options outstanding at the year end was between $nil and $312.00 (2016: $nil and $312.00, 2015: $250.00 to $350.00, 2014: $250.00 to $350.00) per option.

The grant of options during 2016 were at a nil exercise price and therefore the fair value of the options granted was considered to be the share price at the date of grant ($200 per share). To note that, since no options were granted in the six months to 30 June 2017, a share price was not calculated for this period. In the prior years, the options granted were valued by reference to the Black-Scholes option valuation model. Inputs were as follows:

	2014	*2015*
	$000	*$000*
Weighted average share price[1]	$250.00	$250.00
Weighted average exercise price	$250.00	$250.00
Expected volatility	72.30%	97.20%
Expected life (years)	1.54	1.43
Risk-free rate	0.41%	0.38%
Expected dividends	Nil	Nil
Weighted average fair value per option granted	$87.02	$110.00

1. The share price inputs to the share-based payments valuation have been determined on a basis consistent with the issue and valuation of equity linked instruments issued by the Seven Group at a similar time.

34. Non-controlling interests

	$000
At 1 January 2014	22,106
Share of loss for the year	(23,789)
At 1 January 2015	(1,683)
Share of loss for the year	(1,094)
At January 2016	(2,777)
Share of profit for the year	32,844
At 1 January 2017	30,067
Share of loss for the half-year	(899)
At 30 June 2017	29,168

The non-controlling interest relates to the remaining 37.5 per cent. shareholding in the Seven Group's subsidiary, Universal Energy. The Seven Group's 62.5 per cent. shareholding in Universal Energy is expected to be acquired as part of the Agreed Transaction.

35. Related party transactions

The Seven Group, through its subsidiary Universal Energy, holds a Naira denominated loan due to Akwa Ibom Investment and Industrial Promotion Council (a minority shareholder of Universal Energy) for $4.7 million (2016: $5.0 million, 2015: $7.8 million, 2014: $8.5 million). The loan is to be repaid from the production revenues generated by the Stubb Creek field, with repayment, including accrued interest by 30 December 2018. The loan bears interest at 15.0 per cent. per annum from the date of first oil production (February 2015). The Seven Directors are currently in discussions with the lender to reschedule the loan repayments and to update the loan documentation, as the signed loan agreement currently in effect specified first repayment to commence in September 2013. Following delays to first oil production from the field in prior years, no repayments have been made to date, in breach of the current agreement and thus the full amount of the loan is disclosed within Current borrowings – scheduled payments within one year (see note 24).

The International Finance Corporation ("IFC") holds an equity interest in the Seven Group. In addition, the IFC initially subscribed for $50.0 million of Senior Secured Loan Notes, for which, interest accrued and was paid during 2016 in line with the terms outlined in note 24.

In 2016, the Seven Group paid fees of $0.5 million to the Multilateral Investment Guarantee Agency ("MIGA"), the political risk insurance and credit enhancement arm of the World Bank Group, for MIGA to provide an option over a guarantee of up to $200.0 million against risk of expropriation of the Seven Group' wholly owned subsidiary, Accugas Limited. A fellow associated company of the World Bank Group, the International Finance Corporation ("IFC") is a security holder in the Seven Group following its equity investment in 2014.

Remuneration of key management personnel

The Seven Directors and members of the Seven Group's Executive Committee are considered to be the key management personnel of the Seven Group. The remuneration of the key management personnel of the Seven Group is set out below in aggregate:

	Year ended 31 December 2014 $000	*Year ended 31 December 2015 $000*	*Year ended 31 December 2016 $000*	*Six months ended 30 June 2017 $000*
Short-term employee benefits (salaries and wages)	5,650	5,496	2,128	1,000
Other long-term benefits (pension costs)	352	384	265	117
Share-based payments	500	333	73	–
Total remuneration	6,502	6,213	2,466	1,117

36. Interests in subsidiaries and joint arrangements

Details of the subsidiaries and the percentage of share capital owned by the Seven Group as at 30 June 2017 are set out below. All of these subsidiaries are included in the consolidated financial statements:

Name	*Place of incorporation and operation*	*Activity*	*Ownership interest %*	*Voting power held %*
Seven Energy (UK) Ltd	Scotland	Service company	100	100
Seven Uquo Gas Ltd*	Nigeria	Oil and gas exploration and development	100	100
Seven Exploration and Production Ltd	Nigeria	Oil and gas exploration and development	100	100
Universal Energy Resources Ltd*	Nigeria	Oil and gas exploration and development	62.5	62.5
Accugas Ltd^	Nigeria	Gas marketing and distribution	100	100
East Horizon Gas Company Ltd^	Nigeria	Gas marketing and distribution	100	100
E905 Suntera Ltd	Nigeria	Oil and gas exploration	100	100
Gas Transmission & Power Ltd	Nigeria	Oil and gas exploration	100	100
Exoro Energy Limited	Nigeria	Dormant	100	100
Seven Energy (BVI) Limited*	British Virgin Islands	Intermediate holding company	100	100
Seven Energy Finance Limited	British Virgin Islands	Finance Company	100	100
Seven Energy (Jersey) Limited	Jersey	Intermediate Holding Company	100	100
Seven Energy Limited	BermudaFinance Company	100	100	
Exoro Holdings BV*	Netherlands	Intermediate Holding Company	100	100
Domestic Gas Development Company Limited	Nigeria	Dormant	100	100
Septa Oil Trading Company Limited	Nigeria	Dormant	100	100
Ekid Gas Processing Company Limited	Nigeria	Dormant	100	100

* to be acquired as part of the Agreed Transaction

^ Savannah to hold a 20 per cent. per cent. interest in the midstream assets

Details of the Seven Group's interests in joint arrangements as at 30 June 2017 are set out below. The cost of investment and the Seven Group's share of the jointly controlled entity's post acquisition profit or loss and other comprehensive income is included in the Seven Group's consolidated financial statements where applicable:

Name	*Place of incorporation and operation*	*Activity*	*Ownership interest %*	*Voting power held %*
Afren Global Energy Resources Ltd	Nigeria	Oil and gas exploration	22.5	22.5

In the year ended 31 December 2016, the carrying value of the investment in Afren Global Energy Resources Ltd was written off due to no near-term development plans on the licences. Furthermore, the Seven Group had not planned or budgeted for any substantive expenditure due to funding constraints.

Details of the Seven Group's interest in joint operations as at 30 June 2017 are set out below. The Seven Group's share of assets, liabilities, revenues and expenses are included in the Seven Group's consolidated financial statements:

Name	*Joint interest partners*	*Place of incorporation and operation*	*Activity*	*Participating interest %*
Uquo field joint operations*	Frontier Oil Ltd	Nigeria	Oil and gas exploration and development	40
Strategic Alliance Agreement	SINOPEC International Petroleum Exploration and Production Company Nigeria Limited	Nigeria	Oil and gas exploration and development	51
OPL 905 field joint operation	Nigerian Petroleum Development Company Ltd	Nigeria	Oil and gas exploration and development	55[1]
	Ideal Oil and Gas Ltd	Nigeria	Oil and gas exploration and development	90
OPL 907 field joint operation	Buston Energy Resources Ltd Allene Exploration & Production Ltd Bepta Oil & Gas Ltd Kaztec engineering Ltd VP Energy Ltd De Atai Oil Services Ltd	Nigeria	Gas marketing and distribution	41
OPL 917 field joint operation	Petrolog Oil & Gas Ltd VP Energy Ltd Goland Petroleum Ltd De Atai Oil Services Ltd	Nigeria	Gas marketing and distribution	42

* to be acquired as part of the Agreed Transaction

[1] - The Seven Group has 55 per cent. indirect interest in OMLs 4, 38 & 41 via the Strategic Alliance Agreement with NPDC. The Seven Group accounts for the Strategic Alliance Agreement as a jointly controlled operation as it is considered to exercise joint control through its participation in the technical and financial discussions and the decision making process for the development of the blocks through NPDC, and also funds NPDC's 55 per cent. share of costs.

37. Business Combinations

37.1 Suntera

On 31 January 2014, the Seven Group acquired from Suntera Management Limited the entire issued share capital of SRL 905 Holdings Limited, a Jersey incorporated company (now renamed Seven Energy (Jersey)

Limited), and its wholly-owned Nigerian subsidiary Energy 905 Suntera Limited ("E905S"), an oil and gas exploration and production company. E905S has a 40 per cent. licence interest in Oil Prospecting Licence 905 ("OPL 905") which is located in the Anambra basin. OPL 905 is subject to a Production Sharing Contract between the Nigerian National Petroleum Corporation, Gas Transmission and Power Limited, Ideal Oil and Gas Limited and E905S. OPL 905 had a significant identified gas resource base with additional potential upside in the under-explored Anambra basin.

The acquired business contributed $nil revenues and $0.4 million net loss to the Seven Group for the period from acquisition to 31 December 2014. If the acquisition had occurred on 1 January 2014, consolidated revenue and consolidated loss for the year ended 31 December 2014 would have remained materially unchanged. Total acquisition related costs (included in administrative expenses in the consolidated statement of comprehensive income) for the year ended 31 December 2014 was $0.3 million.

	At 31 January 2014 *$000*
Recognised amounts of identifiable assets acquired and liabilities assumed	
Intangible assets	64,131
Property, plant and equipment	81
Cash and cash equivalents	13
Trade and other receivables	206
Trade and other payables	(3,510)
Deferred tax liabilities	(12,921)
Total fair value of net identifiable assets	48,000
Total fair value of consideration	48,000
Consideration satisfied by:	
Cash	15,000
ICLNs	33,000
Buy-back put options	–
Total consideration transferred	48,000
Net cash outflow arising on acquisition	
Cash consideration	15,000
Less: cash and cash equivalents acquired	(13)
Net cash outflow	14,987

As part of the acquisition, the purchase agreement included two buy-back options issued to Suntera Management Limited which enabled them to re-purchase a proportional interest in OPL 905. These options are between Suntera and Seven. Given that Seven is to go into administration as part of the Agreed Transaction, these options will lapse.

This acquisition is related to the Anambra basin, which is not part of the Agreed Transaction.

37.2 East Horizon Gas Company Limited

On 31 March 2014, the Seven Group obtained control of East Horizon Gas Company ("EHGC") by acquiring 100 per cent. of its issued share capital from Oando PLC. EHGC operates the 128 km East Horizon gas pipeline through Akwa Ibom and Cross Rivers States in south east Nigeria. EHGC also has a gas sales agreement with an industrial off-taker to supply up to 25 MMcfpd, increasing to 50 MMcfpd in 2016, under a 20 year gas sales agreement, expiring in 2032.

The acquisition was expected to further enhance the Seven Group's gas marketing and distribution position in the South-east Niger Delta region, expanding the reach of its pipeline network, diversifying its customer base and increasing long-term contracted gas sales volumes.

In the nine months post acquisition, EHGC contributed $21.5 million and $15.6 million to the Seven Group's revenue and profit respectively. If the acquisition had occurred on 1 January 2014, the Seven Group's revenue would have further increased by $6.2 million and profit would have decreased by $7.1 million.

Total acquisition related costs (included in administrative expenses in the consolidated statement of comprehensive income) for the year ended 31 December 2014 was $1.2 million.

	At 31 March 2014 *$000*
Recognised amounts of identifiable assets acquired and liabilities assumed	
Property, plant and equipment	269,822
Cash and cash equivalents	290
Trade and other receivables	3,639
Inventory	1,973
Trade and other payables	(51,229)
Borrowings	(54,301)
Provisions	(15,654)
Net deferred tax liabilities	(18,032)
Total fair value of net identifiable assets	136,508
Total fair value of consideration	136,508
Consideration satisfied by:	
Cash	100,000
Contingent deferred cash	36,508
Total consideration transferred	136,508
Net cash outflow arising on acquisition	
Cash consideration	136,508
Less: cash and cash equivalents acquired	(290)
Net cash outflow	136,218

The fair value of the pipeline asset has been calculated on a discounted cash flow basis, using estimated market prices for gas sales and purchases and also on estimated future pipeline capacity utilisation.

A provision for contingent liabilities amounting to $3.2 million was recognised in respect of certain legal claims against the Company. This provision was fully released by the end of 2015.

The fair value of the consideration was based on a gross consideration of $250.0 million less adjusted net liabilities. The gross consideration included amounts that were contingent upon the seller satisfying a number of post-acquisition operational conditions for the future benefit of EHGC's operations. As previously reported at 30 June 2014, any contingent payments were to be settled equally in cash and through the issue of ICLNs. It was subsequently agreed with the vendor that final settlement would be satisfied entirely in cash.

The amount payable was made up of an initial cash payment of $100.0 million and contingent deferred cash payment of $36.5 million. These post-acquisition conditions were met and the final contingent deferred cash payment was made in November 2014.

EHGC has merged with Accugas (see note 38). Savannah will hold a 20 per cent. interest in the infrastructure assets as part of the Agreed Transaction.

37.3 Afren Global Energy Resources Limited

On 12 December 2014, the Seven Group signed a share purchase agreement with Global Energy Company Limited ("GEC") to acquire up to 72.5 per cent. of the issued share capital of Afren Global Energy Resources Limited ("AGER"), a Nigerian incorporated, oil and gas exploration and production company.

AGER has a 41 per cent. licence interest in Oil Prospecting Licence 907 ("OPL 907") and a 42 per cent. licence interest in Oil Prospecting Licence 917 ("OPL 917") which are both located in the Anambra basin, close to the Seven Group's interest in OPL 905 and subject to a Production Sharing Contract with the Nigerian National Petroleum Corporation. OPLs 907 and 917 had a significant identified gas resource base with additional potential upside in the under-explored Anambra basin.

The acquisition was structured in two parts: 22.5 per cent. of the share capital was acquired on 12 December 2014, and the remaining 50 per cent. (to take the total shareholding to 72.5 per cent.) to be completed in 2015 upon completion of conditions precedent (being principally the placement of a work program performance bond, expected in the first half of 2015).

The total consideration for the full 72.5 per cent. shareholding comprises the following:

– $12.0 million in the form of a promissory note
– $2.0 million in the form of ordinary shares in the company at a price of $250.00 per share
– $0.4 million in the form of cash

The promissory note had an initial six month term and is unsecured and non-interest bearing. The Seven Group had an option to extend the term of the note up to one year (in which case the note would have an 18 month term in total). In that case (a) the note would become interest bearing at LIBOR plus 10 per cent. for the extension period (payable six monthly in arrears) (b) $6.0 million of principal would be repayable on the first anniversary of the note, and (c) SEIL would be required to put a security package in place, to apply during the extension period. The security package would need to be agreed with the lender, whose consent could not be unreasonably withheld or delayed.

As at 31 December 2014, $0.4 million of cash and $12.0 million promissory note were issued in consideration for 22.5 per cent. of the share capital (part 1). At 31 December 2014, the Seven Group was considered to have joint control of AGER on the basis of Board representation and voting rights. The investment is accounted for as a jointly controlled entity using the equity method and fair value consideration principles of IFRS 3, with initial investment recognised at a cost of $11.5 million. Given the short space of time from acquisition date to year end, there was no significant change AGER's post acquisition result and thus the investment contributed $nil profit after tax to the Seven Group for the period from acquisition to 31 December 2014. The additional $2.0 million had not yet been issued as it was subject to a number of conditions precedent.

Total acquisition costs (included in administrative expenses in the consolidated statement of comprehensive income) for the year ended 31 December 2014 were $0.2 million.

This acquisition is related to the Anambra basin, which is not part of the Agreed Transaction.

37.4 Gas Transmission and Power Limited

On 27 February 2015, the Seven Group completed the acquisition of the entire issued share capital of Gas Transmission and Power Limited ("GTPL"), a Nigerian oil and gas exploration and production company, with a 50 per cent. licence interest in, and operatorship of, OPL 905, located in the Anambra basin. OPL 905 had a significant identified gas resource base with additional potential upside in the under-explored Anambra basin. The gross consideration was $27.0 million less $0.9 million of adjusted net liabilities. The $26.1 million net consideration comprised $25.7 million of ICLNs at a conversion price of $250.00 per share, with the remaining being cash.

For the year ended 31 December 2015, GTPL did not contribute to the Seven Group's revenue and contributed $0.1 million loss after tax to the Seven Group's result. Had the acquisition occurred on 1 January 2015, the Seven Group's revenue and result would have remained materially unchanged. Total acquisition related costs (included in administrative expenses in the consolidated statement of comprehensive income) for the year ended 31 December 2015 were immaterial.

	At February 2015 *$000*
Recognised amounts of identifiable assets acquired and liabilities assumed	
Intangible assets	38,678
Property, plant and equipment	24
Cash and cash equivalents	26
Trade and other payables	(1,194)
Deferred tax liabilities	(11,414)
Total fair value of net identifiable assets	26,120
Total fair value of consideration	26,120
Consideration satisfied by:	
Cash	470
ICLNs	25,650
Total consideration transferred	26,120
Net cash outflow arising on acquisition	
Cash consideration	470
Less: cash and cash equivalents acquired	(26)
Net cash outflow	444

This acquisition is related to the Anambra basin and is not to be acquired as part of the Agreed Transaction.

38. Subsequent events after the reporting period

Merger of Accugas Limited and East Horizon Gas Company Limited

On 31 August 2017, Accugas Limited and East Horizon Gas Company Limited, subsidiaries of the Seven Group, merged their trade, assets and liabilities, leaving Accugas as the principal entity for continuing the Seven Group's midstream oil and gas processing and distribution business in Nigeria.

The purpose of the merger was to benefit from economies of scale, operational synergies, reduced costs and create a larger asset base to offer security to existing and future lenders; all of which will be derived from the administration of the current businesses of EHGC and Accugas through a single corporate entity.

Lock-up Agreement effective and provision of short term liquidity facility to Seven

On 15 November 2017, a lock up agreement was entered into between Savannah Petroleum PLC ("Savannah"), Seven Energy International Limited ("Seven"), Seven Energy Finance Limited ("SEFL"), certain other subsidiaries of Seven (together, the "Seven Group") and certain of the creditors of the Seven Group (the "Lock-up Agreement"). The Lock-up Agreement relates to the proposed acquisition by Savannah of certain of the Seven Group's assets (the "Agreed Transaction") and the associated proposed financial restructuring of the Seven Group.

An addendum to the Lock-up agreement is being discussed to reflect the new terms of the transaction.

The Transaction

The Agreed Transaction will involve the acquisition by Savannah of the following Seven Group interests:

- 40 per cent. participating interest in the Uquo oil & gas field;
- 62.5 per cent. interest in Universal Energy Resources Limited ("UERL"), which holds a 51 per cent. participating interest in the Stubb Creek oil & gas field; and
- A 20 per cent. interest in the Accugas Limited ("Accugas") midstream business, a c.260km gas pipeline network and associated gas processing infrastructure, in conjunction with a third-party investors. This will be accounted for as an investment in an associate in the Enlarged Group.

The Lock-up Agreement envisages consideration of US$87.5 million in cash and US$52.5 million in newly issued Savannah shares being paid to the holders of Seven's current 10.25 per cent. Senior Secured Notes ("SSNs") for the release of the SSNs. In addition, the SSNs will have the right to participate, on a pro rata basis, in a US$20 million new capital contribution in exchange for the right to share, on a pro rata basis to the new capital contribution, in a US$26.7 million new Savannah share issuance and a US$20 million new facility issued at the Accugas level. Savannah may choose in certain circumstances to exchange the above equity interests offered to the SSNs into additional cash consideration, as described in more detail in the relevant term sheet in the Lock-Up Agreement.

The Lock-up Agreement also envisages the following:

- the US$24.1 million first bilateral facility agreement to SEFL being exchanged into a US$20 million facility to be reinstated at the Accugas level, on a non-recourse basis to the Company;
- US$7.3 million in cash and US$4.4 million in newly issued Savannah shares being paid to the lender of the second bilateral facility agreement to SEFL as consideration for the release of this loan; and
- the exchange of the Seven Group's 10.50 per cent. senior secured notes due 2021 into US$15 million of notes to be issued at the Accugas level and US$85 million of notes to be issued at a Savannah subsidiary company level, both on a non-recourse basis to the Company.

Savannah Liquidity Facility

Savannah has also agreed to provide to the Seven Group a super senior secured revolving credit facility (the "Liquidity Facility") of up to $20 million to be made available in three tranches as follows:

- firstly, $1.5 million which has been pre-funded to a client account of legal counsel to the Seven Group (and is held subject to an undertaking provided by such legal counsel) and which shall be transferred to an account of Seven upon signing of the Liquidity Facility and the satisfaction of all conditions precedent thereunder and which is only permitted to be withdrawn to finance projected costs in connection with any insolvency, liquidation or administration proceedings involving any member of the Seven Group;
- secondly, $3.5 million available from signing of the Lock-Up Agreement, subject to all conditions precedent to the Liquidity Facility having been satisfied; and
- thirdly, the remaining $15 million available from signing of the Implementation Agreement (subject to all conditions precedent to the Liquidity Facility having been satisfied).

Any drawings under the Liquidity Facility (other than the $1.5 million that has to be pre-funded) are subject to approval by Savannah of the payments to be made from such drawings unless such payments are pre-agreed. Loans under the Liquidity Facility are subject to PIK interest at 6 per cent. p.a. and are repayable in full upon completion of the Agreed Transaction or, if earlier, on termination of either the Lock-up Agreement or the Implementation Agreement.

It is intended that the Liquidity Facility will be used to part fund the advisory and legal fees incurred by Seven as part of the Agreed Transaction. Savannah intends to fund the first and second tranches of the Liquidity Facility from existing cash resources and its revolving loan facility with Oragroup SA. The third tranche is expected to be financed from the proceeds of the proposed equity fundraise.

Calabar NIPP Long term gas sales agreement and World Bank Partial Risk Guarantee

On 25 September 2017, all the conditions precedent to the 20 year Gas Sales Agreement for the supply of gas by Accugas Limited to the Calabar Nigerian Integrated Power Project (the "Calabar GSA") were satisfied and the start date of the Calabar GSA was confirmed as 22 September 2017. The Calabar GSA is supported by a World Bank Partial Risk Guarantee, which is a financial instrument that will secure the supply of up to 131 MMcfpd of natural gas under the Calabar GSA.

Frontier Oil Notices of Default

On 11 December 2017, Frontier Oil Limited ("FOL") issued Notices of Default to Seven Uquo Gas Limited ("SUGL") and Accugas Limited in respect of non-payment of amounts due to Frontier Oil Limited under the terms of the Uquo Joint Operating Agreement between FOL and SUGL and amounts due under various gas sales agreements between FOL, SUGL and Accugas. The failure to cure any default under the terms of these agreements within the grace periods could ultimately result in termination of these agreements and, potentially, the loss by SUGL of any economic interest in the Uquo Field. Any defaults arising under the terms of these agreements can be cured by settlement of the amounts outstanding, full provision for which has been made as at 30 June 2017 to the extent that such liability existed at that date.

PART 9B (i)

HISTORICAL ANNUAL FINANCIAL INFORMATION OF THE EXISTING GROUP

The summary financial information presented below has been extracted without material adjustment from the audited consolidated financial statements for the Company for the 12 month period ended 31 December 2016 and the unaudited interim financial information for the six month period ended 30 June 2017.

Consolidated Statement of Comprehensive Income

	Notes	*Period ended 31 December 2014 $'000*	*Year ended 31 December 2015 $'000*	*Year ended 31 December 2016 $'000*
Operating expenses		(6,831)	(7,044)	(8,412)
Operating profit/(loss)	6	(6,831)	(7,044)	(8,412)
Finance income	8	1	–	207
Finance costs	9	(7,862)	(250)	(126)
Profit/(Loss) before tax		(14,692)	(7,294)	(8,331)
Tax (expense)/credit	10	–	(565)	(1,502)
Profit/(Loss) after tax		(14,692)	(7,859)	(9,833)
Attributable to:				
Owners of the company	11	(14,619)	(7,582)	(9,818)
Non-controlling interests	20	(73)	(277)	(15)
Profit/(Loss) per share ($ per share)				
Basic from continuing operations	11	(0.13)	(0.05)	(0.04)
Diluted from continuing operations	11	(0.13)	(0.05)	(0.04)

Consolidated Statement of Financial Position

	Notes	*Period ended 31 December 2014 $'000*	*Year ended 31 December 2015 $'000*	*Year ended 31 December 2016 $'000*
Non-current assets				
Property, plant and equipment	12	503	734	954
Exploration and evaluation assets	13	42,539	80,529	96,913
		43,042	81,263	97,867
Current assets				
Other receivables and prepayments	15	1,475	410	6,074
Cash and cash equivalents	16	17,221	7,849	23,061
		18,696	8,259	29,135
Total assets		61,738	89,522	127,002
Current liabilities				
Trade and other payables	19	1,977	878	7,777
Corporation tax liabilities		–	565	786
Provisions		417	–	–
		2,394	1,443	8,563
Equity				
Share capital	17	224	321	483
Share premium	17	73,668	108,576	146,892
Capital contribution	17	458	458	458
Other reserves	17	(375)	–	–
Share based payment reserve	17	61	1,223	2,938
Accumulated deficit		(14,619)	(22,149)	(31,967)
Equity attributable to owners of the Company		59,417	88,429	118,804
Non-controlling interests		(73)	(350)	(365)
Total equity		59,344	88,079	118,439
Total equity and liabilities		61,738	89,522	127,002

Consolidated Statement of Changes in Equity

	Share Capital $'000	*Share Premium $'000*	*Capital Contribution $'000*	*Other Reserve $'000*	*Share Based Payment Reserve $'000*	*Accumulated Deficit $'000*	*Total $'000*	*Non-Controlling Interests $'000*	*Total Equity $'000*
Balance at incorporation	–	–	–	–	–	–	–	–	–
Loss for the year and total comprehensive loss	–	–	–	–	–	(14,619)	(14,619)	(73)	(14,692)
Issue of ordinary shares to shareholders, net of issue costs	224	73,668	458	(375)	61	–	74,036	–	74,036
At 31 December 2014	224	73,668	458	(375)	61	(14,619)	59,417	(73)	59,344
Loss for the year and total comprehensive loss	–	–	–	–	–	(7,582)	(7,582)	(277)	(7,859)
Equity settled share based payments	–	–	–	–	1,162	–	1,162	–	1,162
Issue of ordinary shares to shareholders, net of issue costs	97	35,158	–	–	–	–	35,255	–	35,255
Reversal of provision	–	–	–	375	–	52	427	–	427
Uncollected issued share capital and share premium	–	(250)	–	–	–	–	(250)	–	(250)
At 31 December 2015	321	108,576	458	–	1,223	(22,149)	88,429	(350)	88,079
Loss for the year and total comprehensive loss	–	–	–	–	–	(9,818)	(9,818)	(15)	(9,833)
Equity settled share based payments	–	–	–	–	1,715	–	1,715	–	1,715
Issue of ordinary shares to shareholders, net of issue costs	162	38,316	–	–	–	–	38,478	–	38,478
At 31 December 2016	483	146,892	458	–	2,938	(31,967)	118,804	(365)	118,439

Consolidated Statement of Cash Flows

	Period ended 31 December 2014 $'000	*Year ended 31 December 2015 $'000*	*Year ended 31 December 2016 $'000*
Cash flows from operating activities:			
Net cash used in operating activities	(11,349)	(7,853)	(8,457)
Net cash used in operating activities	(11,349)	(7,853)	(8,457)
Cash flows from investing activities:			
Payments for property, plant and equipment	(509)	(344)	(441)
Proceeds from disposal of property, plant and equipment	–	11	97
Exploration and evaluation costs paid	(42,539)	(37,990)	(9,315)
Net cash used in investing activities	(43,048)	(38,323)	(9,659)
Cash flows from financing activities:			
Finance charges	–	(84)	(126)
Proceeds from issues of equity shares, net of issue costs	71,618	36,888	33,454
Net cash provided/(used) by financing activities	71,618	36,804	33,328
Net increase/(decrease) in cash and cash equivalents	17,221	(9,372)	15,212
Cash and cash equivalents at beginning of period	–	17,221	7,849
Cash and cash equivalents at end of period	17,221	7,849	23,061

Notes to the historical financial information

1. Corporate information

The consolidated financial statements of Savannah Petroleum Plc ("Savannah" or the "Company") and its subsidiaries (together the "Group") for the year to 31 December 2016 were authorised for issue in accordance with a resolution of the Board of Directors on 23 May 2017.

Savannah was incorporated in the United Kingdom on 3 July 2014. Savannah's principal activity is the management of its investment in Savannah Petroleum 1 Limited ("SP1"). SP1 was incorporated in Scotland on 3 July 2013. SP1's principal activity is the management of its investment in Savannah Petroleum 2 Limited ("SP2"), and the provision of services to other companies within the Group. SP2 has a 95 per cent. interest in Savannah Petroleum Niger R1/R2 S.A. ("Savannah Niger") whose principal activity is the exploration of hydrocarbons in the Republic of Niger.

The Company is domiciled in the UK for tax purposes and its shares were listed on the Alternative Investments Market ("AIM") of the London Stock Exchange on 1 August 2014.

The Company's registered address is 40 Bank Street, London, E14 5NR.

The Group's functional currency is US dollars ("$").

No dividends have been declared or paid since incorporation.

2. Basis of preparation

The consolidated financial statements of the Group have been prepared in accordance with International Financial Reporting Standards as adopted by the European Union ("IFRSs as adopted by the EU"), IFRIC interpretations and those parts of the Companies Act 2006 applicable to companies reporting under IFRS. The consolidated financial statements have been prepared under the historical cost convention.

The consolidated financial statements of the Group incorporate the results for the year to 31 December 2016.

Going concern

Having carefully reviewed the Group's budgets and its business plans for the next twelve months, the Directors have a reasonable expectation that the Group has adequate resources to continue operating for the foreseeable future. For this reason, the Directors continue to adopt the going concern basis in preparing the Consolidated Financial Statements.

The Group is in a positive net asset position at 31 December 2016, and had at that date $23,061,000 (2015: $7,849,000, 2014: $17,221,000) of cash and cash equivalents to meet its working capital requirements.

During the period to 31st December 2016, the Group executed a three year revolving loan facility for €11.4 million with Oragroup SA, a West and Central Africa focused banking group.

In July 2016 the Company raised $40 million (gross) from issuing new ordinary shares. The use of proceeds of this placing was to fund the start of ground operations in Niger and ongoing corporate purposes.

Basis of consolidation

Subsidiaries

The consolidated financial statements incorporate the financial statements of the Company and its subsidiaries.

Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if, and only if, the Group has:

- Power over the investee (i.e. existing rights that give it the current ability to direct the relevant activities of the investee);

- Exposure, or rights, to variable returns from its involvement with the investee; and
- The ability to use its power over the investee to affect its returns.

Generally, there is a presumption that a majority of voting rights result in control. To support this presumption and when the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- The contractual arrangement with the other vote holders of the investee;
- Rights arising from other contractual arrangements; and
- The Group's voting rights and potential voting rights.

The Group re-assesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the consolidated financial statements from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance.

See note 14 for the companies that have been consolidated within the Group financial statements.

Transactions eliminated upon consolidation

Where necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with those used by other members of the Group. All intra-group transactions, balances, income and expenses are eliminated in full on consolidation.

3. Significant accounting policies

New and amended IFRS standards

The following relevant new standards, amendments to standards and interpretations are mandatory for the first time for the financial year beginning 1 January 2016, but had no significant impact on the Group:

Standard	*Key requirements*	*Effective date as adopted by the EU*
Amendment to IFRS 11, 'Accounting for Acquisitions of Interests in Joint Operations'	Amends IFRS 11 Joint Arrangements to require an acquirer of an interest in a joint operation in which the activity constitutes a business (as defined in IFRS 3 Business Combinations) to: ● apply all of the business combinations accounting principles in IFRS 3 and other IFRSs, except for those principles that conflict with the guidance in IFRS 11; and ● disclose the information required by IFRS 3 and other IFRSs for business combinations. The amendments apply both to the initial acquisition of an interest in joint operation, and the acquisition of an additional interest in a joint operation (in the latter case, previously held interests are not remeasured).	1 January 2016

Standard	Key requirements	Effective date as adopted by the EU
Amendments to IAS 16 and IAS 38	Clarifies acceptable methods of depreciation and amortisation.	1 January 2016
Amendments to IAS 16 and IAS 41	Update on Agriculture: Bearer Plants.	1 January 2016
Amendments to IAS 27	Amends IAS 27 Separate Financial Statements to permit investments in subsidiaries, joint ventures and associates to be optionally accounted for using the equity method in separate financial statements.	1 January 2016
Amendments to IAS 1	Disclosure amendments.	1 January 2016

Standards issued but not yet effective

The following relevant new standards, amendments to standards and interpretations have been issued, but are not effective for the financial year beginning on 1 January 2016, as adopted by the European Union, and have not been early adopted:

Standard	Key requirements	Effective date as adopted by the EU
IFRS 9	Financial Instruments – Replacement to IAS 39 and is built on a single classification and measurement approach for financial assets which reflects both the business model in which they are operated and their cash flow characteristics.	1 January 2018
IFRS 15	Revenue from contracts with customers – Introduces requirements for companies to recognise revenue for the transfer of goods or services to customers in amounts that reflect the consideration to which the company expects to be entitled in exchange for those goods or services. Also results in enhanced disclosure about revenue.	1 January 2018
IFRS 16	Leases – Introduces a single lessee accounting model and eliminates the previous distinction between an operating and a finance lease.	1 January 2019

The Directors anticipate that the adoption of these Standards and Interpretations in future periods will have no material impact on the financial statements of the Company when the relevant standards and interpretations come into effect.

Foreign currency translation

Transactions and balances

Transactions entered into in a currency other than the functional currency are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. At each statement of financial position date, the monetary assets and liabilities of the Group's entities that are not in the functional currency of that entity are translated into the functional currency at exchange rates prevailing at the statement of financial position date. The resulting exchange differences are recognised in the Statement of Comprehensive Income.

Functional and presentation currency

Management has concluded that the US dollar is the functional currency of each entity of the Group due to it being the currency of the primary economic environment in which the Group operates, based on the following facts:

- Most of the expenses of the entities of the Group are denominated in US dollars; and
- The majority of funds raised from financing activities (debt or equity instruments) are either generated in US dollars or are raised in GBP and immediately converted to US dollars.

The consolidated financial statements are presented in US dollars.

Property, plant and equipment

Property, plant and equipment is stated at cost less accumulated depreciation and any accumulated impairment losses. Cost includes expenditure that is directly attributable to the acquisition of the items.

Depreciation is provided at rates calculated to write each asset down to its estimated residual value evenly over its expected useful life as follows:

	(Years)
Computers	3
Motor Vehicles	4
Equipment	5-10
Furniture and fixtures	5-10

An asset's carrying amount is written down immediately to its recoverable amount if the asset's carrying amount is greater than its estimated recoverable amount.

Investments in subsidiaries

Investments in subsidiaries are stated in the parent company's statement of financial position at cost less any provisions for impairment. If a distribution is received from a subsidiary, then the investment in that subsidiary is assessed for an indication of impairment.

Loan note conversion

Loan notes converted to equity are recognised in equity at the settlement amount of the loan note, on the settlement date, being the legal amount of the debt that is released for the issue of shares.

Where a premium that would be due to a loan note holder under the terms of the loan note agreement is waived on conversion, a capital contribution is recognised in equity in respect of the value of the waived premium.

The difference between the settlement amount under the conversion, and the historic carrying value of the loan notes, is recognised as a finance cost within statement of comprehensive income.

Segmental analysis

In the opinion of the Directors, the Group is primarily organised into a single operating segment. This is consistent with the Group's internal reporting to the chief operating decision maker. Separate segmental disclosures have therefore not been included.

Exploration and evaluation assets

Intangible assets relate to exploration, evaluation and development expenditure and are accounted for under the 'successful efforts' method of accounting per IFRS 6 'Exploration for an Evaluation of Mineral Resources'. The successful efforts method means that only costs which relate directly to the discovery and development of specific oil and gas reserves are capitalised. Exploration and evaluation costs are valued at costs less accumulated impairment losses and capitalised within intangible assets. Development expenditure on producing assets is accounted for in accordance with IAS 16, 'Property, plant and equipment'. Costs incurred prior to obtaining legal rights to explore are expensed immediately to the statement of comprehensive income.

Impairment

Property, plant and equipment and intangible assets excluding exploration and evaluation assets

At each statement of financial position date, the Group reviews the carrying amounts of its property, plant and equipment and intangible assets to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any).

The recoverable amount is the higher of fair value less costs to sell and value in use. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash flows. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted. If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in statement of comprehensive income.

Non-financial assets which have suffered an impairment are reviewed for possible reversal of the impairment at each reporting date. Where an impairment loss subsequently reverses, the carrying amount of the asset (cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognised for the asset (cash-generating unit) in prior periods. A reversal of an impairment loss is recognised immediately in statement of comprehensive income.

Exploration and evaluation assets

Impairment tests are performed when the Group identifies facts or circumstances implying a possible impairment in accordance with IFRS 6. Where the Group identifies that an asset may be impaired the Group performs an assessment of the recoverable value in accordance with the requirements of IFRS 6. Any impairment identified is immediately charged to the statement of comprehensive income.

Financial assets

Cash and cash equivalents

Cash and cash equivalents consist of cash on hand and demand deposits.

Amounts due from Group and other receivables

Other receivables are measured at amortised cost using the effective interest method less any impairment.

Impairment of financial assets

Financial assets are assessed for indicators of impairment at each statement of financial position date. Financial assets are impaired where there is objective evidence that, as a result of one or more events that occurred after the initial recognition of the financial asset, the estimated future cash flows of the investment have been impacted.

The carrying amount of the financial asset is reduced by the impairment loss directly for all financial assets.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognised, the previously recognised impairment loss is reversed through profit or loss to the extent that the carrying amount of the asset at the date the impairment is reversed does not exceed what the amortised cost would have been had the impairment not been recognised.

Financial liabilities and equity

Debt and equity instruments are classified as either financial liabilities or as equity in accordance with the substance of the contractual arrangement.

Equity instruments

Equity instruments issued by the Company are recorded at the proceeds received, net of direct issue costs, which are charged to share premium.

Trade payables

Trade payables are measured at fair value.

Taxation

The tax expense represents the sum of the tax currently payable.

Current tax

The tax currently payable is based on taxable profit for the period. Taxable profit differs from profit as reported in the statement of comprehensive income because it excludes items of income or expense that are taxable or deductible in other periods and it further excludes items that are never taxable or deductible. The Group's liability for current tax is calculated using tax rates that have been enacted or substantively enacted by the statement of financial position date.

Deferred tax

Deferred tax is recognised on differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit and is accounted for using the statement of financial position liability method.

Deferred tax liabilities are generally recognised for all taxable temporary differences, and deferred tax assets are generally recognised for all deductible temporary differences to the extent that it is probable that taxable profits will be available against which those deductible temporary differences can be utilised. Such assets and liabilities are not recognised if the temporary difference arises from goodwill or from the initial recognition (other than in a business combination) of other assets and liabilities in a transaction that affects neither the taxable profit nor the accounting profit.

Deferred tax liabilities are recognised for taxable temporary differences associated with investments in subsidiaries and associates, and interests in joint ventures, except where the Group is able to control the reversal of the temporary difference and it is probable that the temporary difference will not reverse in the foreseeable future.

The carrying amount of deferred tax assets is reviewed at each statement of financial position date and reduced to the extent that it is no longer probable that sufficient taxable profits will be available to allow all or part of the asset to be recovered. Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period in which the liability is settled or the asset realised, based on tax rates (and tax laws) that have been enacted or substantively enacted by the statement of financial position date. The measurement of deferred tax liabilities and assets reflects the tax consequences that would follow from the manner in which the Group expects, at the reporting date, to recover or to settle the carrying amount of its assets and liabilities.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Group intends to settle its current tax assets and liabilities on a net basis.

Current and deferred tax for the period

Current and deferred tax are recognised as an expense or income in profit or loss, except when they relate to items credited or debited directly to equity or other comprehensive income, in which case the tax is also recognised directly in equity or other comprehensive income, as appropriate.

Value Added Tax

When VAT is expected to be recoverable through the existence of future sales, the Group's policy is to record this recoverable VAT as a non-current tax asset. In instances where the future recoverability of VAT cannot be assessed with sufficient confidence, the Group's policy is to add the potentially irrecoverable VAT to the cost of the underlying transaction and capitalise or expense the amount according to the treatment of the underlying transaction.

Share-based payments

The Group issues equity-settled share-based payments to some of its employees and Directors through stock options plans, restricted shares or warrants. In accordance with IFRS 2, these plans are measured at fair value on the grant date and are accounted for as an employee expense on a straight-line or graduated vesting for each tranche basis over the vesting period of the plans.

The equity settled transaction reserve accounts for the expense associated with options that have been granted but not yet vested. The cost of the share options is recognised as an increase in the equity settled transaction reserve at the time of the award and this reserve is transferred to the accumulated deficit account over time when such shares become vested.

The proceeds received net of any directly attributable costs are credited to share capital (nominal value) and share premium in the Company.

The Company has the obligation to deliver the shares, and it is a Group subsidiary company that employs the individuals. In the Company's separate financial statements, there is no share-based payment charge, as no employees are providing services to the Company. The Company recognises an increase in the investment in the employing subsidiary as a capital contribution from the parent and a corresponding increase in equity.

Capital

The capital structure of the Group consists of equity attributable to the owners of the Company, comprising issued capital, the capital contribution reserve, the other reserve in respect of stamp tax arising on the issue of equity, the share based payment reserve and the accumulated deficit.

Share capital

Share capital comprises issued capital in respect of issued and paid up shares, at their par value.

Share premium

Share premium comprises the difference between the proceeds received and the par value of the issued and paid up shares.

Capital contribution

The capital contribution reserve comprises the capital contribution that was made by shareholders of the Company as part of the debt to equity conversion.

Share based payment reserve

The share based payment reserve relates to equity-settled share-based payments provided to employees, including key management personnel, as part of their remuneration.

Accumulated deficit

Accumulated deficit comprises the accumulated deficit retained by the Company.

The Group's objective when managing capital is to maintain adequate financial flexibility to preserve its ability to meet financial obligations, both current and long term and to maintain an optimal capital structure to reduce the cost of capital.

The capital structure of the Group is managed and adjusted to reflect changes in economic conditions.

The Group funds its expenditures on commitments from existing cash and cash equivalent balances, received from the issue of shares. There are no externally imposed capital requirements. Financing decisions are made by the Directors based on forecasts of the expected timing and level of capital and operating expenditure required to meet the Group's commitments and development plans.

Leasing

Operating lease payments are recognised as an expense on a straight-line basis over the lease term, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

Earnings per share

(i) *Basic earnings per share*

Basic earnings per share is determined by dividing net profit after income tax attributable to members of the Company, excluding any costs of servicing equity other than ordinary shares, by the weighted average number of ordinary shares outstanding during the financial year, adjusted for bonus elements in ordinary shares issued during the year.

(ii) *Diluted earnings per share*

Diluted earnings per share adjusts the figures used in the determination of basic earnings per share to take into account the after income tax effect of interest and other financing costs associated with dilutive potential ordinary shares and the weighted average number of shares assumed to have been issued for no consideration in relation to dilutive potential ordinary shares.

4. Critical accounting judgements and key sources of estimation uncertainty

In the application of the Group's accounting policies, which are described above, the Directors are required to make judgements, estimates and assumptions about the carrying amounts of assets and liabilities that are not readily apparent from other sources. The estimates and associated assumptions are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

The estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognised in the period in which the estimate is revised if the revision affects only that period, or in the period of revision and future periods if the revision affects both current and future periods.

Critical accounting judgements and key sources of estimation uncertainty

Recoverability of exploration and evaluation costs

The outcome of ongoing exploration, and therefore the recoverability of the carrying value of intangible exploration and evaluation assets, is inherently uncertain. Management makes the judgements necessary to implement the Group's policy with respect to exploration and evaluation assets and considers these assets for impairment at least annually with reference to indicators in IFRS 6. Further details are provided in note 13.

Share based payments

The share-based payment charge is determined based on a number of judgements, including the selection of an appropriate valuation model, and is based on the estimation of the number of awards that will ultimately vest, and vesting periods. Further details are provided in note 18.

5. Segmental reporting

The Group complies with IFRS 8 Operating Segments, which requires operating segments to be identified on the basis of internal reports about components of the Group that are regularly reviewed by the Chief Executive to allocate resources to the segments and to assess their performance.

In the opinion of the Directors, the operations of the Group comprise one class of business, being oil and gas exploration and related activities in only one geographical area, Niger.

6. Operating loss

Operating loss has been arrived at after charging:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Depreciation of property, plant and equipment	6	97	124
Staff costs (note 7)	916	3,552	4,766

During the year the Group (including its overseas subsidiaries) obtained the following services from the company's auditor:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Fees payable to Grant Thornton UK LLP for the audit of the Company's annual accounts	53	78	77
Total audit fees payable to Grant Thornton UK LLP and their associates	53	78	77
Fees payable to Grant Thornton UK LLP and their associates for other services to the group:			
– Audit-related assurance services	8	11	11
– Other taxation advisory services	168	138	25
– Services related to corporate finance transactions	130	–	–
Total non-audit fees payable to Grant Thornton UK LLP and their associates	306	149	36

7. Staff costs

The average monthly number of employees, (including executive Directors) during the year was:

	Period Ended 31 December 2014 Number	*Year Ended 31 December 2015 Number*	*Year Ended 31 December 2016 Number*
Employees	4	12	13

Employee benefits recognised as an expense during the period comprised:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Wages and salaries	723	2,041	2,551
Share based payments	61	1,162	1,715
Pension costs	28	61	76
Social security costs & benefits	104	288	424
	916	3,552	4,766

Director's remuneration during the year comprised:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Wages and salaries	485	954	1,105
Share based payments	55	898	1,508
Pension costs	28	61	55
Social security costs & benefits	64	133	156
	632	2,046	2,824

8. Finance income

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Interest income on short-term bank deposits	1	–	–
Foreign exchange gain	–	–	207

9. Finance costs

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Loan note conversion	7,459[1]	–	–
Foreign exchange losses	290[2]	166	–
Share based payment charge	61	–	–
Bank charges	10	13	15
Other finance costs	42	71	111
	7,862	250	126

1 In the accounting period ended 31 December 2014, loan notes issued by the company were redeemed or converted into ordinary share capital immediately upon the company being listed on the Alternative Investment Market (AIM). The amount of $7,459,000 represents non-recurring and includes non-cash costs related to the treatment of debt to equity conversion conducted around the time of IPO.

2 The net foreign exchange loss booked is US$290k and is mainly the result of the movements of Sterling and XOF against the US dollar during the period.

10. Income tax

The tax expense for the Group is:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
UK Corporation tax	–	565	1,502

	Period Ended 31 December 2014 $'000	Year Ended 31 December 2015 $'000	Year Ended 31 December 2016 $'000
The charge for the period can be reconciled per the statement of comprehensive income as follows:			
Loss on ordinary activities before taxes	14,692	7,294	8,331
Loss before taxation multiplied by the UK corporation tax rate of 20% (2015: 20.25%)	3,232	1,477	1,666
Effects of:			
Expenses disallowed for tax	(878)	(398)	(485)
Tax losses carried forward	(2,354)	(1,120)	(1,203)
Controlled foreign entity charge	–	(524)	(1,480)
Tax charge for the period	–	(565)	(1,502)

As of 1 April 2016, the corporation tax rate is 20 per cent.

At 31 December 2016, tax losses were $22,315,000 (2015: $16,300,000, 2014: $10,702,000). Tax losses will be carried forward and are potentially available for utilisation against taxable profits in future years. The potential tax benefit of the tax losses carried forward at 20 per cent. is $4,463,000 (2015: $3,260,000, 2014: $2,140,000).

At 31 December 2016, a temporary difference for corporation tax purposes in respect of share based payments of $2,938,000 (2015: $1,223,000, 2014: $61,000) existed, which is potentially available for utilisation against taxable profits in future years.

The Group has not recognised a deferred tax asset in respect of tax losses and temporary differences as it does not currently meet the recognition criteria of IAS 12 'Income Taxes'. The asset will be recognised in future periods when its recovery (against appropriate taxable profits) is considered probable.

11. Earnings per share

Basic loss per share amounts are calculated by dividing the loss for the period attributable to owners of the parent by the weighted average number of ordinary shares outstanding during the period.

Diluted loss per share amounts are calculated by dividing the loss for the periods attributable to owners of the parent by the weighted average number of ordinary shares outstanding during the period, plus the weighted average number of shares that would be issued on the conversion of dilutive potential ordinary shares into ordinary shares. The effect of share options is anti-dilutive, and is therefore excluded from the calculation of diluted loss per share.

	Period ended 31 December 2014 $'000	Year ended 31 December 2015 $'000	Year ended 31 December 2016 $'000
Net loss attributable to owners of the parent	14,619	7,582	9,818
	Number of shares	*Number of shares*	*Number of shares*
Basic and diluted weighted average number of shares	113,056,632	160,878,154	229,221,183
Loss per share	*$*	*$*	*$*
Basic and diluted	0.13	0.05	0.04

In July 2016 the Company issued 81,280,000 new ordinary shares as part of an equity fund raising to the value of $40 million (gross).

12. Property, plant and equipment

Cost	*Computer equipment $'000*	*Equipment $'000*	*Furniture & fixtures $'000*	*Motor Vehicle $'000*	*Total $'000*
At incorporation	–	–	–	–	–
Additions	2	396	111	–	509
Balance at 31 December 2014	2	396	111	–	509
Additions	–	235	109	–	344
Disposals	–	(17)	–	–	(17)
Balance at 31 December 2015	2	614	220	–	836
Additions	1	–	45	395	441
Disposals	–	(97)	–	–	(97)
Balance at 31 December 2016	3	517	265	395	1,180

Accumulated depreciation	*Computer equipment $'000*	*Equipment $'000*	*Furniture & fixtures $'000*	*Motor Vehicle $'000*	*Total $'000*
At incorporation	–	–	–	–	–
Depreciation charge	–	–	(6)	–	(6)
Balance at 31 December 2014	–	–	(6)	–	(6)
Depreciation charge	(1)	(56)	(40)	–	(97)
Disposal	–	1	–	–	1
Balance at 31 December 2015	(1)	(55)	(46)	–	(102)
Depreciation charge	(1)	(47)	(46)	(30)	(124)
Balance at 31 December 2016	(2)	(102)	(92)	(30)	(226)
Net book value					
Balance at 31 December 2014	2	396	105		503
Balance at 31 December 2015	1	559	174	–	734
Balance at 31 December 2016	1	415	173	365	954

13. Exploration and evaluation assets

Exploration and evaluation assets consist of acquisition costs relating to the acquisition of exploration licenses and other costs associated directly with the discovery and development of specific oil and gas reserves in the R1/R2 and R3/R4 licence area in the Republic of Niger.

	Total $'000
At incorporation	–
Additions	42,539
Balance at 31 December 2014	42,539
Additions	37,990
Balance at 31 December 2015	80,529
Additions	16,384
Balance at 31 December 2016	96,913

The amount for intangible exploration and evaluation assets represents active exploration projects. These will ultimately be written off to the statement of comprehensive income as exploration costs if commercial reserves are not established but are carried forward in the statement of financial position whilst the determination process is not yet completed and there are no indications of impairment having regard to the indicators in IFRS 6.

14. Investment in subsidiaries

The Group subsidiaries are disclosed below. Transactions between subsidiaries and parent company are eliminated on consolidation.

Name	*Nature of business*	*Country of incorporation*	*Type of share*	*Group shareholding*
Savannah Petroleum 1 Limited	Investment company	United Kingdom	Ordinary	100%
Savannah Petroleum 2 Limited	Investment company	United Kingdom	Ordinary	95%
SPN Limited	Holding	Jersey	Ordinary	100%
Savannah Petroleum SAS	Service	France	Ordinary	100%
Savannah Niger R1/R2 SA	Oil exploration company	Niger	Ordinary	95%

The table below shows details of non-wholly owned subsidiaries of the Group that have material non-controlling interests:

Name	*Proportion of ownership interests and voting rights held by non-controlling interests*	*Loss allocated to non-controlling interests in period ended 31 December 2014 $'000*	*Loss allocated to non-controlling interests in year ended 31 December 2015 $'000*	*Loss allocated to non-controlling interests in year ended 31 December 2016 $'000*	*Accumulated non-controlling interests $'000*
Savannah Petroleum 2 Limited	5%	–			–
Savannah Niger R1/R2 SA	5%	(73)	(277)	(15)	(365)
		(73)	(277)	(15)	(365)

15. Other receivables and prepayments

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Prepayments	186	242	761
VAT receivables	1,039	71	192
Other receivables	250	97	5,121
	1,475	410	6,074

Company receivables of $29,269,000 (2015: $43,295,000, 2014: $45,971,000) and other receivables of $5,118,000 (2015: $94,000, 2014:$250,000) are receivable within one year by the group and are not interest bearing. Other receivables include $5,024,824 relating to unpaid called up share capital.

The Directors consider that the carrying amount of other receivables and prepayments approximates to their fair value and no amounts are provided against them. The Directors consider any change in the credit quality of the receivable from the date credit was granted to the reporting date.

16. Cash and cash equivalents

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Cash and cash equivalents	17,221	7,849	23,061

The Directors consider that the carrying amount of cash and cash equivalents approximates their fair value.

The amount of cash and cash equivalents denominated in currencies other than $ is shown in note 21 to these financial statements.

17. Capital and reserves

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Fully paid ordinary Shares in issue (number)	131,337,172	193,341,447	264,489,510
Called up ordinary Shares in issue (number)			10,131,937
Par value per share in GBP	0.001	0.001	0.001

	Number of Shares	*Share Capital $'000*	*Share Premium $'000*	*Total $'000*
At Incorporation	10	–	–	–
Shares issued	131,337,162	224	73,668	73,892
At 31 December 2014	131,337,172	224	73,668	73,892
Shares issued	62,004,275	97	35,158	35,255
Called up share capital	–	–	(250)	(250)
At 31 December 2015	193,341,447	321	108,576	108,897
Shares issued	81,280,000	162	38,316	38,478
At 31 December 2016	274,621,447	483	146,892	147,375

In July 2016, 81,280,000 ordinary shares of £0.001 were issued as part of an equity fund raising to the value of $40 million (gross). $5 million of new shares issued remain unpaid and are included as part of other debtors. Following the year-ended 31 December 2016, the funds were received.

	Capital contribution $'000	Other reserve $'000	Share based payment reserve $'000	Total $'000
At Incorporation	–	–	–	–
Loan note conversion	458	–	–	458
Group structuring	–	(375)	–	(375)
Share based payments expense during the year	–	–	61	61
At 31 December 2014	458	(375)	61	144
Reversal of provision	–	375	–	375
Share based payments expense during the year	–	–	1,162	1,162
At 31 December 2015	458	–	1,223	1,681
Share based payments expense during the year	–	–	1,715	1,715
At 31 December 2016	458	–	2,938	3,396

Nature and purpose of reserves

Share based payment reserve

The share-based payment reserve is used to recognise the value of equity-settled share-based payments provided to employees, including key management personnel, as part of their remuneration. Further details of share based payments are at note 18.

Capital risk management

The Group manages its capital to ensure that entities in the Group will be able to continue as a going concern while seeking to maximise the return to shareholders through the optimisation of the debt and equity balance.

Details of the Group's capital structure can be found in the capital accounting policy.

The proceeds are used to finance the Group's ongoing development and appraisal of the exploration and evaluation assets.

18. Share-based payments

The Group operates a share option plan as part of the remuneration of employees.

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Share-based payments	61	1,162	1,715

The Board has established a share option plan, in which share options will be granted and vest on successful completion of certain milestones (described below). The Group signed agreements with the key management personnel setting out the terms of the options in 2014. Under IFRS 2 the options were therefore deemed to have been granted in 2014. Once the Remuneration Committee has confirmed the successful completion of the milestone, a certain number of share options will be granted and vest for each participant.

Milestone	*Number of options*	*Assumed Exercise price*	*Market vesting condition*	*Assumed Vesting period*
1	15,737,896	£0.01	PLC share price to equal or exceed £1.68	10 years

Given that milestone is a market vesting condition, the likelihood of it occurring will be re-assessed at each year end and the charge amended annually.

The options were valued on the grant date using a Monte-Carlo option pricing model which calculates the fair value of an option by using the vesting period, the expected volatility of the share price, the current share price, the assumed exercise price and the risk free interest rate. The fair value of the option is amortised over the anticipated vesting period. There is no requirement to revalue the option at any subsequent date.

For valuation purposes an exercise price of £0.01 was used however shares in the Company will be issued at an effective exercise price of £0.56.

Movements in the number of share options outstanding and their related weighted average assumed exercise prices are as follows:

	Charge during the period $'000	*Number of options No.*	*Assumed exercise price per share*
Outstanding at the beginning of the period	–	–	–
Granted during the period	–	15,737,896	£0.01
Charge during the period	61	–	–
Lapsed during the period	–	–	–
Exercised during the period	–	–	–
Outstanding at 31 December 2014		15,737,896	
Charge during the year	659	–	–
Granted, lapsed, exercised during the year	–	–	–
Outstanding at 31 December 2015		15,737,896	
Charge during the year	595	–	–
Granted, lapsed, exercised during the year	–	–	–
Outstanding at 31 December 2016		15,737,896	

The calculation of the share option charge per share using the Monte-Carlo Pricing model has been calculated to be $0.37. Based on the modelling assumptions vesting conditions, a charge of $595,000 for the year to 31 December 2016 (2015: $659,000, 2014: $61,000) has been recognised.

The following table lists the inputs to the model used to determine the fair value of options granted:

Pricing model used	Monte-Carlo
Grant date	28 November 2014
Weighted average share price at grant date	£0.36
Weighted average exercise price	£0.01
Weighted average contractual life (years)	10
Share price volatility (%)	89.69
Dividend yield	–
Risk-free interest rate (%)	1.924

The expected share price volatility of 89.69 per cent. has been determined by reference to historical prices of shares in the following comparator group companies: Tullow Oil Plc, Bowleven Plc, President Energy Plc, Sound Energy PLC (previously Sound Oil Plc) and Ascent Resources Plc.

In the year to 31 December 2015 a supplementary share option plan was established.

Supplementary share option plan

The Board has established a share option plan, in which share options will be granted and vest on successful completion of certain milestones (described below). The Group signed agreements with the key management personnel setting out the terms of the options in 2015. Under IFRS 2 the options were therefore deemed to have been granted in 2015. Once the Remuneration Committee has confirmed the successful completion of the milestone, a certain number of share options will be granted and vest for each participant.

Milestone	*Number of options*	*Assumed Exercise price*	*Market vesting condition*	*Assumed Vesting period*
1	10,128,599	£0.38	PLC share price to equal or exceed £1.14	10 years

Given that milestone is a market vesting condition, the likelihood of it occurring will be re-assessed at each year end and the charge amended annually.

The options were valued on the grant date using a Monte-Carlo option pricing model which calculates the fair value of an option by using the vesting period, the expected volatility of the share price, the current share price, the assumed exercise price and the risk free interest rate. The fair value of the option is amortised over the anticipated vesting period. There is no requirement to revalue the option at any subsequent date. Movements in the number of share options outstanding and their related weighted average assumed exercise prices are as follows:

	Charge during the period $'000	*Number of options No.*	*Assumed exercise price per share*
Outstanding at 1 January 2015	–	–	–
Granted during the year	–	10,128,599	£0.38
Charge during the year	503	–	–
Lapsed and exercised during the year	–	–	–
Outstanding at 31 December 2015		10,128,599	
Charge during the year	1,111	–	–
Granted, lapsed, exercised during the year	–	–	–
Outstanding at 31 December 2016		10,128,599	

The calculation of the share option charge per share using the Monte-Carlo Pricing model has been calculated to be $0.39. Based on the modelling assumptions vesting conditions, a charge of $1,111,000 for the year to 31 December 2016 (2015: $503,000) has been recognised.

The following table lists the inputs to the model used to determine the fair value of options granted:

Pricing model used	Monte-Carlo
Grant date	30 July 2015
Weighted average share price at grant date	£0.40
Weighted average exercise price	£0.38
Weighted average contractual life (years)	10
Share price volatility (%)	82.34
Dividend yield	–
Risk-free interest rate (%)	1.519

The expected share price volatility of 82.34 per cent. has been determined by reference to historical prices of shares in the following comparator group companies: Tullow Oil Plc, Bowleven Plc, President Energy Plc, Sound Energy Plc and Ascent Resources Plc.

Supplementary share option plan

The Board has established a share option plan, in which share options will be granted and vest on successful completion of certain milestones (described below). The Group signed agreements with the key management personnel setting out the terms of the options in 2016. Under IFRS 2 the options were therefore deemed to have been granted in 2016. Once the Remuneration Committee has confirmed the successful completion of the milestone, a certain number of share options will be granted and vest for each participant.

Milestone	*Number of options*	*Assumed Exercise price*	*Market vesting condition*	*Assumed Vesting period*
1	526,315	£0.38	PLC share price to equal or exceed £1.14	10 years

Given that milestone is a market vesting condition, the likelihood of it occurring will be re-assessed at each year end and the charge amended annually.

The options were valued on the grant date using a Monte-Carlo option pricing model which calculates the fair value of an option by using the vesting period, the expected volatility of the share price, the current share price, the assumed exercise price and the risk free interest rate. The fair value of the option is amortised over the anticipated vesting period. There is no requirement to revalue the option at any subsequent date. Movements in the number of share options outstanding and their related weighted average assumed exercise prices are as follows:

	Charge during the period $'000	*Number of options No.*	*Assumed exercise price per share*
Outstanding at 1 January 2016	–	–	–
Granted during the year	–	526,315	£0.38
Charge during the year	9	–	–
Lapsed and exercised during the year	–	–	–
Outstanding at 31 December 2016		526,315	

The calculation of the share option charge per share using the Monte-Carlo Pricing model has been calculated to be $0.21 for Tranche 1 and $0.22 for Tranche 2. Based on the modelling assumptions vesting conditions, a charge of $9,702 for the year to 31 December 2016 has been recognised.

The following table lists the inputs to the model used to determine the fair value of options granted:

Pricing model used	Monte-Carlo
Grant date	10 August 2016
Weighted average share price at grant date	£0.30
Weighted average exercise price	£0.38
Weighted average contractual life (years)	10
Share price volatility (%)	61.28
Dividend yield	–
Risk-free interest rate (%)	0.13

The expected share price volatility of 61.28 per cent. has been determined by reference to historical prices of shares in the following comparator group companies: Tullow Oil Plc, Bowleven Plc, President Energy Plc, Sound Energy Plc.

19. Trade and other payables

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Trade payables	486	804	475
Accruals	1,491	74	7,302
	1,977	878	7,777

The Directors consider that the carrying amount of trade and other payables approximates to their fair value. All amounts are payable within one year.

20. Non-controlling interests

Summarised financial information in respect of each of the Group's subsidiaries that has material non-controlling interests is set out below. The summarised financial information below represents amounts before intragroup eliminations.

Savannah Niger

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Current assets	236	85	16,549
Non-current assets	42,816	79,958	96,924
Current liabilities	(44,509)	(91,016)	(124,269)
Non-current liabilities	–	–	–
	(1,457)	(10,973)	(10,796)
Equity attributable to owners of the Group	(1,384)	(10,623)	(10,431)
Non-controlling interests	(73)	(350)	(365)
	(1,457)	(10,973)	(10,796)

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Net loss and total comprehensive loss	1,457	5,531	277
Attributable to owners of the Group	1,384	5,254	262
Attributable to the non-controlling interest	73	277	15
	1,457	5,531	277
Net cash outflow from operating activities	(1,457)	(9,129)	(277)
Net cash inflow from financing activities	1,608	9,024	1,429
Net cash inflow/(outflow)	151	(105)	1,152

Further information about non-controlling interests is given in note 14.

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Balance at 1 January and incorporation	–	73	350
Share of loss for the year	73	277	15
Balance at 31 December	73	350	365

21. Financial instruments

(a) *Financial instruments by category*

At the end of the year, the Group held the following financial instruments:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Financial assets			
Cash and cash equivalents	17,221	7,849	23,061
Amounts due from group companies	–	–	–
Other receivables	250	98	5,121
	17,471	7,947	28,182
Financial liabilities measured at amortised cost			
Trade payables	(486)	(812)	(475)
Accruals	–	–	(7,302)
Net financial instruments	16,985	7,135	20,405

(b) *Risk management policy*

In the context of its business activity, the Group operates in an international environment in which it is confronted with market risks, specifically foreign currency risk and interest rate risk. It does not use derivatives to manage and reduce its exposure to changes in foreign exchange rates and interest rates.

Cash and cash equivalents are generally kept in the Company's functional currency except for an amount corresponding to the needs of the local subsidiaries and such funds required for the parent company to pay its Directors, employees and vendors who are paid in Sterling. The policy of the Group is to have a balance in the currency of the local subsidiaries not higher than the expected needs in local currency for one month.

In addition to market risks, the Group is also exposed to liquidity and credit risk.

Credit risk

Credit risk is the risk of financial loss to the Group if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Group's receivables and deposits with financial institutions. The Group's exposure to credit risk is influenced mainly by the individual characteristics of each counterparty. The Group has an established credit policy under which each new counterparty is analysed for creditworthiness before the Group's standard terms and conditions are offered. The Group's review includes external ratings.

The maximum exposure the Group will bear with a single customer is dependent upon that counterparty's credit rating, the level of anticipated trading and the time period over which this is likely to run. The Group gives careful consideration to which organisations it uses for its banking services in order to minimise credit risk. Further details of Credit risk are included in note 15.

Liquidity risk

Liquidity risk is the risk that the Group will not be able to meet its financial obligations as they fall due. The Group's approach to managing liquidity is to ensure that it will always have sufficient liquidity to meet its liabilities when due, without incurring unacceptable losses or damage to the Group's reputation.

The Group manages liquidity risk by regularly reviewing cash requirements by reference to short term cash flow forecasts and medium term working capital projections prepared by management.

All surplus cash is aggregated to maximise the returns on deposits through economies of scale.

The Group maintains good relationships with its banks. At 31 December 2016, the Group had $23,061,000 (2015: $7,849,000) of cash reserves (Company: $21,794,000 2015: $7,640,000).

Ultimate responsibility for liquidity risk management rests with the Board of Directors. The Group manages liquidity risk by maintaining adequate cash reserves and continuously monitoring forecast and actual cash flows. The Group aims to maximise operating cash flows in order to be in a position to finance the investments required for its development.

During the period to 31 December 2016 the Group has executed a revolving loan facility of €11.4 million to mitigate liquidity risk.

The Group's liquidity position and its impact on the going concern assumption are discussed further in the Financial Review and Directors' Report.

All the Group's financial liabilities are due within one year at 31 December 2015 and 2016.

Foreign currency risk

Foreign currency risk arises because the Group operates in various parts of the world whose currencies are not the same as the functional currency in which the Group is operating. The net assets from such overseas operations are exposed to currency risk giving rise to gains or losses on retranslation into the presentational currency.

Foreign currency risk also arises when the Group enters into transactions denominated in a currency other than its functional currency. The main foreign currency risk in the period ended 31 December 2016 relates to transactions denominated in Sterling. The Group keeps foreign currency bank accounts in the United Kingdom.

The primary exchange rate movements that the Group is exposed to are $US:XOF and $US:GBP. Foreign exchange risk arises from recognised assets and liabilities.

The carrying amounts of the Group's foreign currency denominated monetary assets and liabilities were as follows:

As at 31 December 2014	*GBP $'000*	*XOF $'000*	*EUR $'000*
Cash and cash equivalents	3,013	151	–
Exposure assets	3,013	151	–
Trade payables	(388)	(69)	(9)
Exposure liabilities	(388)	(69)	(9)
Net exposure	2,625	82	(9)

As at 31 December 2015	*GBP $'000*	*XOF $'000*	*EUR $'000*
Cash and cash equivalents	890	48	10
Exposure assets	890	48	10
Trade payables	(631)	(127)	(67)
Exposure liabilities	(631)	(127)	(67)
Net exposure	259	(79)	(57)

As at 31 December 2016	GBP $'000	XOF $'000	EUR $'000
Cash and cash equivalents	2,947	1,203	287
Exposure assets	2,947	1,203	287
Trade payables	(412)	–	(21)
Accruals	–	–	–
Exposure liabilities	(412)	–	(21)
Net exposure	2,535	1,203	266

The following table shows the effect of the $ strengthening by 10 per cent. against the foreign currencies, with all other variables held constant, on the Group's result for the period. 10 per cent. is the rate used internally when reporting to key management personnel and represents management's assessment of the reasonably possible change in exchange rates.

As at 31 December 2014	*GBP* *$'000*	*XOF* *$'000*	*EUR* *$'000*	*Total* *$'000*
Impact on loss for the period – Group	(239)	(7)	1	(245)

As at 31 December 2015	*GBP* *$'000*	*XOF* *$'000*	*EUR* *$'000*	*Total* *$'000*
Impact on loss for the period – Group	(39)	–	–	(39)

As at 31 December 2016	*GBP* *$'000*	*XOF* *$'000*	*EUR* *$'000*	*Total* *$'000*
Impact on loss for the period – Group	(231)	(109)	(24)	(364)

The following table shows the effect of the $ weakening by 10 per cent. against the foreign currencies, with all other variables held constant, on the Group's result for the period. 10 per cent. is the rate used internally when reporting to key management personnel and represents management's assessment of the reasonably possible change in exchange rates.

As at 31 December 2014	*GBP* *$'000*	*XOF* *$'000*	*EUR* *$'000*	*Total* *$'000*
Impact on loss for the period – Group	292	9	(1)	300

As at 31 December 2015	*GBP* *$'000*	*XOF* *$'000*	*EUR* *$'000*	*Total* *$'000*
Impact on loss for the year – Group	39	–	–	39

As at 31 December 2016	*GBP* *$'000*	*XOF* *$'000*	*EUR* *$'000*	*Total* *$'000*
Impact on loss for the year – Group	231	109	24	364

Interest rate risk

The Group had significant cash balances during the period. Changes in interest rates could have either a negative or positive impact on the Group's interest income. Whenever possible, cash balances are put on term deposits to maximize interest income.

The interest rate profile of the Group's financial assets and liabilities was as follows:

	Period Ended 31 December 2014 $'000	*Year Ended 31 December 2015 $'000*	*Year Ended 31 December 2016 $'000*
Cash at bank at floating interest rate – Group	17,221	7,849	23,061

All other financial instruments were non-interest bearing. The cash at bank at floating interest rates consist of deposits which earn interest at variable rates depending on length of term and amount on deposit.

At 31 December 2016, a 1 per cent. increase in short-term interest rates would have a positive $231,000 (2015: $78,000, 2014: $172,000) impact on Group loss before tax and equity and a positive $218,000 (2015: $78,000, 2014: $171,000) impact on Company loss before tax and equity. A 1 per cent. decrease in short-term interest rates would have a negative $231,000 (2015: $78,000, 2014: $172,000) impact on Group loss before tax and equity and a negative $218,000 (2015: $78,000, 2014: $171,000) impact on Company loss before tax and equity. A 1 per cent. movement represents management's assessment of the reasonable possible change in interest rates.

22. Related party transactions

Transactions between the Company and its subsidiaries which are related parties of the Company have been eliminated on consolidation and are not disclosed in this note. Details of transactions between the Company and other related parties are disclosed below.

Compensation of key management personnel

Key management are the Directors (executive and non-executive).

Trading transactions

During the year, Group companies entered into the following transactions with related parties who are not members of the Group.

	Period Ended 31 December 2014		*Year Ended 31 December 2015*		*Year Ended 31 December 2016*	
	Outstanding	*Management services*	*Outstanding*	*Management services*	*Outstanding*	*Management services*
	$'000	*$'000*	*$'000*	*$'000*	*$'000*	*$'000*
Lothian Oil & Gas Partners LLP	–	692	–	441	30	453

Andrew Knott is a member of Lothian Oil & Gas Partners LLP ("LOGP") and the Chief Executive Officer of Savannah Petroleum PLC. As discussed on Page 57 of the Company's AIM Admission Document of 1 August 2014, LOGP incurred costs of $2,002,000 relating to the Group's activities prior to admission to AIM. $500,000 of these costs was recharged to the Company on admission. In addition, post-admission, LOGP has continued to provide services to Savannah pursuant to a contract entered into on 28 July 2014, to enable Savannah to continue to benefit from the professional services of individuals affiliated to LOGP on an as required basis. Since the Company entered into this agreement with LOGP, Andrew Knott has not received remuneration from LOGP and is not expected to going forward.

23. Notes to the consolidated statement of cash flows

	Period ended 31 December 2014 $'000	*Year ended 31 December 2015 $'000*	*Year ended 31 December 2016 $'000*
Loss for the period before tax	(14,692)	(7,294)	(8,331)
Adjustments for:			
Depreciation and amortisation	6	97	122
Finance costs	6,601	84	126
Issue costs	(3,868)	(1,634)	–
Share option charge	61	1,162	1,715
Profit/loss on disposal	–	6	–
Non-cash movement in provision	41	10	–
Operating cash flows before movements in working capital	(11,851)	(7,569)	(6,368)
(Increase)/Decrease in other receivables and prepayments	(1,475)	816	(170)
(Decrease) in trade and other payables	1,977	(1,100)	(638)
Income tax paid	–	–	(1,281)
Net cash outflow from operations	(11,349)	(7,853)	(8,457)

24. Commitments

At the reporting date for 2016, the Group had outstanding commitments of $8 million in relation to seismic contract acquisition (2015: $Nil, 2014: $3,196,000).

25. Operating lease arrangements

	Period ended 31 December 2014 $'000	*Year ended 31 December 2015 $'000*	*Year ended 31 December 2016 $'000*
Lease payments under operating leases recognised as an expense during the period	16	63	305

At the statement of financial position date, the group had outstanding commitments for future minimum lease payments under non-cancellable operating leases, which fall due as follows:

	Period ended 31 December 2014 $'000	*Year ended 31 December 2015 $'000*	*Year ended 31 December 2016 $'000*
Within one year	73	288	194
In the second to fifth years inclusive	57	1,133	975
	130	1,421	1,169
Total prepaid as at year end	80	59	36
Total outstanding commitment as at year end	50	2,598	1,900
	130	2,657	1,936

Operating lease payments represent rentals payable by the Group for certain of its office properties. Leases are negotiated with a minimum period of 2 years, and for an average term of 4 years, and rentals are fixed over the lease period.

PART 9B (ii)

HISTORICAL INTERIM FINANCIAL INFORMATION OF THE EXISTING GROUP

Consolidated Statement of Comprehensive Income

	Notes	*Six months ended 30 June 2016 $000*	*Six months ended 30 June 2017 $000*
Operating Expenses		(3,532)	(5,944)
Operating loss		(3,532)	(5,944)
Finance income		8	174
Finance costs		(9)	(35)
Loss before tax		(3,533)	(5,805)
Income tax		(761)	(7)
Net loss and total comprehensive loss		(4,294)	(5,812)
Total comprehensive loss attributable to:			
Owners of the parent		(4,173)	(5,810)
Non-controlling interests		(121)	(2)
		(4,294)	(5,812)
Loss per share			
Basic and diluted ($)	4	(0.02)	(0.02)

Consolidated Statement of Financial Position as at June 2017

	Notes	*Six months ended 30 June 2016 $000*	*Six months ended 30 June 2017 $000*
Assets			
Non-Current Assets			
Property, plant and equipment		681	2,537
Exploration and evaluation assets	3	82,148	108,068
Total non-current assets		82,829	110,605
Current Assets			
Other receivables and prepayments		3,411	857
Cash and cash equivalents		700	8,409
Total current assets		4,111	9,266
Total Assets		86,940	119,871
Equity and Liabilities			
Capital and reserves			
Share capital	5	321	483
Share premium	5	108,576	146,892
Capital contribution	5	458	458
Other reserve	5	–	–
Share based payment reserve	5	2,119	3,727
Accumulated deficit		(26,322)	(37,777)
Equity attributable to owners of the Group		85,152	113,783
Non-controlling interests		(471)	(367)
Total equity		84,681	113,416
Current Liabilities			
Trade and other payables		996	6,455
Corporation tax liability		1,263	–
Total current liabilities		2,259	6,455
Total Equity and Liabilities		86,940	119,871

Consolidated Statement of Cash Flows as at June 2017

	Six months ended 30 June 2016 $000	*Six months ended 30 June 2017 $000*
Cash flows from operating activities:		
Loss for the period before tax	(3,533)	(5,805)
Depreciation and amortisation	54	108
Share option charge	896	789
Finance costs	9	34
Operating cash flows before movements in working capital	(2,574)	(4,874)
Decrease/(increase) in other receivables and Prepayments	(3,001)	193
(Decrease)/increase in trade and other payables	55	435
Income tax paid	–	(7)
Net cash outflow from operations	(5,520)	(4,253)
Cash flows from investing activities:		
Payments for property, plant and equipment	(1)	(1,691)
Proceeds from disposal of property, plant and equipment	–	–
Exploration and evaluation costs paid	(1,619)	(13,698)
Net cash used in investing activities	(1,620)	(15,389)
Cash flows from financing activities:		
Finance charges	(9)	(34)
Proceeds from issues of shares, net of issue costs	–	5,024
Net cash provided by financing activities	(9)	4,990
Net decrease in cash and cash equivalents	(7,149)	(14,652)
Cash and cash equivalents at beginning of period	7,849	23,061
Cash and cash equivalents at end of period	700	8,409

Consolidated Statement of Changes in Equity as at June 2017

	Share Capital $000	*Share Premium $000*	*Capital Contribution $000*	*Share Based Payment Reserve $000*	*Accumulated Deficit $000*	*Total $000*	*Non-Controlling Interests $000*	*Total Equity $000*
Balance at 31 December 2015	321	108,576	458	1,223	(22,149)	88,429	(350)	88,079
Equity settled share based payment	–	–	–	896	–	896	–	896
Loss for the period and total comprehensive loss	–	–	–	–	(4,173)	(4,173)	(121)	(4,294)
Balance at 30 June 2016	321	108,576	458	2,119	(26,322)	85,152	(471)	84,681
Issue of ordinary shares to shareholders, net of issue costs	162	38,316	–	–	–	38,478	–	38,478
Equity settled share based payment	–	–	–	819	–	819	–	819
Loss for the period and total comprehensive loss	–	–	–	–	(5,645)	(5,645)	106	(5,539)
Balance at 31 December 2016	483	146,892	458	2,938	(31,967)	118,804	(365)	118,439
Equity settled share based payments	–	–	–	789	–	789	–	789
Loss for the period and total comprehensive loss	–	–	–	–	(5,810)	(5,810)	(2)	(5,812)
Balance at 30 June 2017	483	146,892	458	3,727	(37,777)	113,783	(367)	113,416

NOTES TO THE HISTORICAL FINANCIAL INFORMATION

1. General information

Savannah was incorporated in the United Kingdom on 3 July 2014. Savannah's principal activity is the management of its investment in Savannah Petroleum 1 Limited ("SP1"). SP1 was incorporated in Scotland on 3 July 2013. SP1's principal activity is the management of its investment in Savannah Petroleum 2 Limited ("SP2"), and the provision of services to other companies within the Group. SP2 has a 95 per cent. interest in Savannah Petroleum Niger R1/R2 S.A. ("Savannah Niger") whose principal activity is the exploration of hydrocarbons in the Republic of Niger.

2. Accounting policies

Basis of Preparation

The condensed consolidated financial statements have been prepared using the same accounting policies that applied to the Group's latest annual audited financial statements. The provisions of IAS 34 'Interim Financial Reporting' have not been applied.

The condensed consolidated financial statements do not include all disclosures that would otherwise be required in a complete set of financial statements and should be read in conjunction with the 2016 Annual Report. The financial information for the six months ended 30 June 2017 does not constitute statutory accounts within the meaning of Section 434(3) of the Companies Act 2006 and is unaudited.

The annual financial statements of Savannah Petroleum PLC are prepared in accordance with IFRSs as adopted by the European Union. The Independent Auditors' Report on that Annual Report and financial statements for 2016 was unqualified, did not draw attention to any matters by way of emphasis, and did not contain a statement under 498(2) or 498(3) of the Companies Act 2006.

The Group's statutory financial statements for the year ended 31 December 2016 have been filed with the Registrar of Companies.

All amounts have been prepared in US dollars, this being the Group's functional currency and its presentational currency.

Going concern

Having carefully reviewed the Group's budgets and its business plans for the next twelve months, the Directors have a reasonable expectation that the Group has adequate resources to continue operating for the foreseeable future. For this reason, the Directors continue to adopt the going concern basis in preparing the Consolidated Financial Statements.

The Group is in a positive net asset position at 30 June 2017 and has access to incremental liquidity through the revolving loan facility of €11.4 million with Oragroup SA, a West and Central Africa focused banking group.

Intangible exploration and evaluation assets

Intangible assets relate to Exploration, evaluation and development expenditure and are accounted for under the 'successful efforts' method of accounting per IFRS 6 'Exploration for an Evaluation of Mineral Resources'. The successful efforts method means that only costs which relate directly to the discovery and development of specific oil and gas reserves are capitalised. Exploration and evaluation costs are valued at cost less accumulated impairment losses and capitalised within intangible assets. Development expenditure on producing assets is accounted for in accordance with IAS 16, 'Property, plant and equipment'. Costs incurred prior to obtaining legal rights to explore are expensed immediately to the income statement.

Segmental analysis

In the opinion of the directors, the Group is primarily organised into a single operating segment. This is consistent with the Group's internal reporting to the chief operating decision maker. Separate segmental disclosures have therefore not been included.

3. Exploration and evaluation assets

Exploration and Evaluation assets consist of acquisition costs relating to the acquisition of exploration licenses and other costs associated directly with the discovery and development of specific oil and gas reserves in the R1/R2 and R3/R4 license areas.

	Six months ended 30 June 2016 Unaudited $000	*Six months ended 30 June 2017 Unaudited $000*
Exploration and evaluation assets	82,148	108,068

The amounts for Exploration and Evaluation assets represent active exploration projects. These will ultimately be written off to the statement of comprehensive income as exploration costs if commercial reserves are not established, but are carried forward in the statement of financial position whilst the determination process is ongoing. There are no indications of impairment having regard to the indicators in IFRS 6.

Exploration and evaluation costs of $11,156,000 incurred in the period to 30 June 2017 relate mainly to Exploration Drilling and Seismic Acquisition costs in relation to the R1/R2 and R3/R4 licences.

4. Loss per share

Basic loss per share amounts are calculated by dividing the loss for the period attributable to ordinary equity holders by the weighted average number of ordinary shares outstanding during the period.

Diluted loss per share amounts are calculated by dividing the loss for the periods attributable to ordinary holders by the weighted average number of ordinary shares outstanding during the period, plus the weighted average number of shares that would be issued on the conversion of dilutive potential ordinary shares into ordinary shares. The effect of share options is anti-dilutive, and is therefore excluded from the calculation of diluted loss per share.

Details of share capital movements are given in note 5.

	Six months ended 30 June 2016 $000	*Six months ended 30 June 2017 $000*
Net loss attributable to owners of the parent	4,173	5,810
	Number of shares	*Number of shares*
Basic and diluted weighted average number of shares	274,621,447	274,621,447
	$	*$*
Basic and diluted loss per share	0.02	0.02

5. Share capital

	As at 30 June 2016	*As at 30 June 2017*
Issued and fully paid ordinary shares in issue (number)	193,341,447	274,621,447
Par value per share in GBP	0.001	0.001

	Number of Shares	Share Capital $000	Share Premium $000	Total $000
At 30 June 2016	193,341,447	321	108,576	108,897
Shares issued	81,280,000	162	38,316	38,478
At 30 June 2017	274,621,447	483	146,892	147,375

Other capital reserves

	Capital contribution $000	Share based payment reserve $000	Total $000
At 30 June 2016	458	2,119	2,577
Share based payments expense during the year	–	819	819
At 31 December 2016	458	2,938	3,396
Share based payments expense during the period	–	789	789
At 30 June 2017	458	3,727	4,186

Nature and purpose of reserves

Capital contribution reserve

On 1 August 2014 a capital contribution of $458,000 was made by shareholders of the Group as part of the loan note conversion.

Share based payment reserve

The share-based payment reserve is used to recognise the value of equity-settled share-based payments provided to employees, including key management personnel, as part of their remuneration.

6. Capital commitments

At the reporting date the Group had no outstanding capital commitments as at 30 June 2017. The commitment in relation to the drilling contract is up to date. (30 June 2016: $2.5 million).

7. Related parties

The related party transactions for the interim and prior period are as follows:

	Outstanding $000	Management services $000
Lothian Oil & Gas Partners LLP:		
At 30 June 2017	31	120
At 30 June 2016	24	180

Andrew Knott is a member of Lothian Oil & Gas Partners LLP ("LOGP") and the Chief Executive Officer of Savannah Petroleum PLC. As discussed on Page 57 of the Company's AIM Admission Document of 1 August 2014, LOGP incurred costs of $2,002,000 relating to the Group's activities prior to admission to AIM. $500,000 of these costs was recharged to the Company on admission. In addition, post-admission, LOGP has continued to provide services to Savannah pursuant to a contract entered into on 28 July 2014, to enable Savannah to continue to benefit from the professional services of individuals affiliated to LOGP on an as required basis. Since the Company entered into this agreement with LOGP, Andrew Knott has not received remuneration from LOGP and is not expected to going forward.

PART 10

UNAUDITED PRO FORMA STATEMENT OF NET ASSETS OF THE ENLARGED GROUP

Section A: Introduction

The unaudited pro forma financial information set out below has been prepared to illustrate the effect of the Acquisition, Accugas Transaction, Capital Restructuring and Placing on the net assets of Savannah Petroleum plc as if the Acquisition, Accugas Transaction, Capital Restructuring and Placing has taken place on 30 June 2017. The unaudited pro forma financial information has been prepared on the basis of, and should be read in conjunction with, the notes set out below.

The unaudited pro forma statement of net assets of the Enlarged Group is based on the net assets of Savannah Petroleum plc as at 30 June 2017 and has been prepared on the basis that the Acquisition, Accugas Transaction, Capital Restructuring and Placing was effective as of 30 June 2017 and in a manner consistent with the accounting policies to be adopted by Savannah in preparing the audited financial statements for the current financial year ending 31 December 2017.

Because of its nature, the unaudited pro forma financial information addresses a hypothetical situation and, therefore, does not represent the Enlarged Group's actual financial position or results. It may not, therefore, give a true picture of the Enlarged Group's financial position or results nor is it indicative of the results that may, or may not, be expected to be achieved in the future. The pro forma financial information has been prepared for illustrative purposes only and in accordance with Annex II of the Prospectus Directive Regulation.

Section B: Unaudited Pro Forma Statement of Net Assets of the Enlarged Group

	The Company Note 1 US$'000	*Seven Energy Note 2 US$'000*	*Adjustments Note 3 US$'000*	*Note 4 US$'000*	*Note 5 US$'000*	*Note 6 US$'000*	*Pro forma US$'000*
Non-current assets							
Long term investment	–	–	–	–	–	15,000	15,000
Property, plant and equipment	2,537	782,726	(397,779)	(125,147)	–	–	262,337
Exploration and evaluation assets	108,068	–	–	–	–	–	108,068
Other receivables	–	3,343	(8,509)	7,167	–	–	2,001
Deferred tax assets	–	260,294	(188,103)	(4,567)	–	–	67,624
	110,605	1,046,363	(594,391)	(122,547)	–	15,000	455,030
Current assets							
Inventories	–	197,410	(2,558)	(194,153)	–	–	699
Trade and other receivables	857	85,488	(73,924)	(282,601)	282,798	–	12,618
Cash and cash equivalents	8,409	14,150	(8,749)	(2,681)	–	41,600	52,729
	9,266	297,048	(85,231)	(479,435)	282,798	41,600	66,046
Total assets	119,871	1,343,411	(679,622)	(601,982)	282,798	56,600	521,076
Current liabilities							
Trade and other payables	6,455	543,222	(216,706)	(412,141)	100,084	–	20,914
Borrowings	–	838,850	(370,342)	(449,224)	(14,610)	–	4,674
Deferred revenue	–	7,636	(7,637)	4,082	–	–	4,081
Current tax liabilities	–	784	–	(784)	–	–	–
	6,455	1,390,492	(594,685)	(858,067)	85,474	–	29,669
Non-current liabilities							
Borrowings	–	–	–	–	–	85,000	85,000
Deferred tax liabilities	–	6,721	–	–	–	–	6,721
Provisions	–	46,097	(33,153)	–	–	–	12,944
Deferred revenue	–	56,394	(56,441)	7,167	–	–	7,120
	–	109,212	(89,594)	7,167	–	85,000	111,785
Total liabilities	6,455	1,499,704	(684,279)	(850,900)	85,474	85,000	141,454
Net assets	113,416	(156,293)	4,657	248,918	197,324	(28,400)	379,622

Notes

(1) The net assets of the Company as at 30 June 2017 have been extracted without adjustment from the Interim Condensed Statements of Financial Position set out in Savannah's unaudited interim financial statements for the period ended 30 June 2017.

(2) The net assets of the Seven Energy Group as at 30 June 2017 to be acquired have been extracted without material adjustment from the Statements of Financial Position, set out in Part 9A of this Admission Document.

(3) The adjustment in Note 3 reflects the deconsolidation of the net assets of Accugas Limited and East Horizon Limited upon AIIM acquiring a controlling 80 per cent. stake from Seven Group, resulting in a 20 per cent. non-controlling equity investment held by Savannah. The consideration allocation for the acquisition of the 20 per cent. non-controlling interest in Accugas, the target midstream business is US$15 million on the basis of the Investment Agreement.

The pro forma does not reflect either (i) the option to increase Savannah's investment in Accugas Holdco by acquiring up to a further 10 per cent. of the shares in Accugas Holdco at a price of US$7.5 million plus 10 per cent. of any Invested Capital provided by the Shareholders, in each case plus an amount equivalent to interest on such amount at the rate of 10 per cent. per annum, or (ii) the funding commitments undertaken by Savannah in the Shareholders' Agreement of US$10 million, which may only be drawn down if Accugas Holdco is unable to service its cash interest payments due to revenue shortfall not provided for in the business plan. The adjustment reflects the retention of current trade receivable balance between Uquo and Accugas of c.US$17m for outstanding gas sales, per the provisions of the Lock-Up Agreement.

The information has been extracted without material adjustment from the consolidation schedules used as a basis for the Historical Financial Information of Seven Group, set out in Part 9A of this Admission Document.

This deconsolidation adjustment is based on the provisions of the Investment Agreement and assumes that Accugas Acquisition is accounted for as an equity investment in the Enlarged Group's financial information. The Investment Agreement was executed on 21 December 2017 with the agreed form Accugas Shareholder Agreement appended to it. The agreed form Shareholder Agreement contains provisions which are critical to concluding on the appropriate basis for accounting for the Accugas Transaction under IFRS10 and 11 and therefore this adjustment will be subject to reassessment based on the final signed Shareholders Agreement and Relationship Agreement.

(4) The adjustment in Note 4 reflects the planned liquidation, disposal or disaggregation of entities outside the perimeter of the transaction including assets and liabilities relating to Seven's Strategic Alliance Agreement (SAA) with NPDC and the Anambra basin. The information has been extracted without material adjustment from the consolidation schedules used as a basis for the Historical Financial Information of Seven Group, set out in Part 9A of this Admission Document.

(5) The adjustment in Note 5 reflects the impact of debt restructuring and the conversion of inter group debt to equity amounting to US$197 million. Subsequent to the debt restructuring, the Akwa Ibom State loan amounting to US$4.6 million remains as the only short-term borrowings in the Enlarged Group.

The adjustment does not reflect the SSNs which may be held by Savannah following an exchange offer or Scheme of Arrangement.

There may be certain tax risks which may arise as a result of the debt and intercompany restructuring which have not been reflected in the proforma. Included with Deferred Tax assets is an amount of US$17 million in respect of unutilised losses and US$50 million in respect of Accelerated Capital Allowance. Savannah have assumed these amounts to be fully recoverable and that they do not expect the change over Ownership of the assets to restrict any of the tax losses or Capital Allowances.

No adjustment has been made to reflect the draw down from the €11.4 million revolving loan facility with Oragroup SA by Savannah Niger since 30 June 2017, amounting to €8.8 million as at the date of this Admission document.

(6) The adjustment in Note 6 reflects:

(a) The cash effect of the Placing and the cash Consideration payable for the purchase of Seven Energy Group assets, which is payable upon completion.

	US$'000
Proceeds from the Placing	125,000
Expenses relating to the Placing	(12,500)
Net proceeds of the Placing	112,500
Cash consideration for Transaction	(50,900)
Transaction costs (as described below)	(20,000)
Net adjustment to cash in respect of the Acquisition, Accugas Transaction, Capital Restructuring and Placing	41,600

Total proceeds of the Placing to be received by the Company are US$125 million by the issue of new ordinary shares of £0.001 each. The net proceeds to be received by the Company are US$112.5 million, after US$12.5 million of expenses relating to the Placing and including US$0.63 million of stamp duty.

Transaction costs represent costs incurred in connection with the Acquisition, Accugas Transaction and Capital Restructuring. The costs also include expenses relating to legal due diligence, accounting and finance due diligence, tax due diligence, accounting advice, tax advice, legal advice, competent persons report on assets and financial advisor fees.

The adjustment in Note 6 does not reflect the impact of the establishment of an EBT as disclosed in Section 25 of Part 1 of this document.

(b) The consideration payable by the Company for the Seven Group assets being acquired is US$282.3 million as at the date of this Admission document, of which US$50.9 million will be paid in cash.

		US$'000
Total consideration		282,300
Consideration settled in cash	50,900	
Consideration settled in shares	146,400	
Assuming of third party debt	85,000	

The adjustment in Note 6 does not reflect the difference between the purchase consideration paid of US$282.3 million and the net assets acquired of US$294.6 million. The net assets being acquired is the cumulative effect of Notes 2, 3,4 and 5 as set out above. A fair value assessment of the consideration, assets and liabilities acquired, including a valuation of the intangible assets, as required by IFRS 3 (Revised) has not yet been performed and therefore the allocation of value between intangible assets and the individual assets and liabilities in the Company's first consolidated accounts and estimation of the related impact on the income statement, if any, will be determined on Completion.

(7) No adjustment has been made to reflect the trading results of Savannah Petroleum plc since 30 June 2017 or of Seven Energy Group since 30 June 2017 or of any other changes in their respective financial positions in these periods.

PART 11

COMPETENT PERSON'S REPORT FOR SEVEN ASSETS

Working together
for a safer world

Competent Person's Report: Niger Delta Assets - Uquo and Stubb Creek Marginal Fields

Report for:

Savannah Petroleum plc

Reference:
K17SAV002L

Reporting date:
December 2017

Report status:
Final

Author(s)	Allan Spencer, Natasha Hird, Christopher Priddis, Colin Clarke
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Release to Client	David Tobias
Date Released	21st December 2017 (final)

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21st December 2017

Dear Sirs,

EVALUATION OF SEVEN ENERGY INTERNATIONAL LIMITED'S PETROLEUM INTERESTS

In accordance with the instructions of the Directors of Savannah Petroleum plc (Savannah), Strand Hanson Limited (Strand Hanson) and Barclays Bank plc and the engagement letter dated 19th July 2017 between Savannah and Senergy (GB) Limited (Lloyd's Register or LR), LR has reviewed a portfolio of assets in Nigeria currently owned by Seven Energy International Limited (Seven Energy) and its subsidiary companies, together known as the (Group). This portfolio comprises the Uquo and Stubb Creek Marginal Fields (together the South East Niger Delta assets).

Savannah Petroleum plc (Savannah) is in the process of acquiring certain Seven Energy Group assets in Nigeria and requires a Competent Person's Report (CPR) to be issued to Savannah covering these assets.

Seven Energy has given LR permission to refer to and apply prior audit work undertaken on these assets by LR and its subsidiary, Senergy, in the period 2014 to the present, as a basis for the CPR generation. LR has also reviewed and assessed proprietary analysis work done by Savannah on the assets.

The interests evaluated comprise licence areas that contain fields which are in production, under development and/or subject to appraisal, and prospective acreage.

This report provides an independent evaluation of the recoverable hydrocarbons expected for each asset categorised in accordance with the 2007 and 2011 Petroleum Resources Management System (PRMS) prepared by the Oil and Gas Reserves Committee of the Society of Petroleum Engineers (SPE) and reviewed and jointly sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE). The results of this work have been presented in accordance with the requirements of the AIM Market of the London Stock Exchange and the European Securities and Market Authority (ESMA), in particular as described in the "Note for Mining and Oil and Gas Companies - June 2009".

LR has evaluated the portfolio of assets, as of 1st November 2017 for which LR is informed that Seven Energy has ownership rights with the equity interest indicated in the asset description section of this report. The reserve and resource data on which this report is based are the responsibility of the Seven Energy and Savannah management. LR's responsibility is to express an opinion on the reserve and resource data based on its evaluation. LR confirms that, to the best of its knowledge, there has been no material change of circumstances or available information since the effective date. LR has no responsibility to update this report for events and circumstances occurring after the preparation date.

Gross Reserves on Licence are defined as the total estimated petroleum to be produced from the fields on the licences evaluated with an effective date of 1st November 2017 after application of any economic cut-off. Net attributable Reserves and Contingent Resources are defined as those portions of the gross Reserves owned by the Group or to which the Group is entitled, as derived from the economic evaluation for each of the assets specified in Section 4. Prospective Resources are expressed as gross on licence and estimated net attributable[1] as a detailed economic evaluation has not been run on these resources.

[1] Net attributable resources is that volume potentially accruing to Seven Energy calculated by applying the terms of the current Joint Venture Agreements, and is not necessarily the same as net entitlement as the latter will depend on the contractual terms of the licence and the cost structure of the projects at the time of any eventual hydrocarbon production.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. These techniques rely on engineering and geo-scientific interpretation and judgment. Hence the hydrocarbon Reserves and Resources included in this evaluation represent LR's best professional judgment and should not be considered a guarantee of results. It should be recognised that any evaluation of hydrocarbon Reserves and/or Resources may increase or decrease in future if there are changes to the available information, technical interpretation, economic criteria or regulatory requirements. As far as LR is aware there are no special factors that would affect the operation of the assets which would require additional information for their proper appraisal.

The content of this report and LR's estimates of Reserves and Resources are based on data provided by Savannah and Seven Energy, including that provided for previous Seven Energy CPRs in 2015 and 2016. New additional geological and geophysical data and analysis has been provided by Savannah for the Uquo and Stubb Creek Marginal Fields. Data provided for audit of other fields and prospects and for the interpretation of assessed in-place volumes are largely unchanged from previous years' Seven Energy reports. Site visits were not undertaken by LR, but Savannah and Strand Hanson visited the Uquo and Stubb Creek Marginal Fields and midstream processing facilities.

LR acknowledges that this report may be included in its entirety, or portions of this report summarised, in documents prepared by Savannah and its advisers in connection with commercial or financial activities and that such documents, together with this report, may be filed with the AIM Market of the London Stock Exchange and may be published electronically on websites accessible by the public, including a website of Savannah.

Executive Summary

This report comprises an independent evaluation of the recoverable hydrocarbons for certain interests of the Group in licences located onshore Nigeria.

In the South East Niger Delta, Seven Energy International Limited (Seven Energy) holds: (i) a 40% participating interest in the Uquo Marginal Field via its 100% owned subsidiary Seven Uquo Gas Limited (SUGL) with Frontier Oil Limited (FOL) holding the remaining 60% interest and (ii) a 62.5% interest in its subsidiary Universal Energy Resources Limited (UERL), which in turn holds a 51% interest in the Stubb Creek Marginal Field, with Sinopec International Petroleum Exploration and Production Company Nigeria Limited (SIPEC) holding the remaining 49% interest. FOL is the operator of the Uquo Marginal Field and UERL is the operator of the Stubb Creek Marginal Field.

The economic interests of Seven Energy in these fields are not necessarily equal to the participating interests and are derived from the commercial agreements between Seven Energy and its partners. An economic model derived by Savannah and reviewed and deemed fit for purpose by LR has been used to determine net economic interests and entitlements.

The assets evaluated include fields under development with Reserves and development opportunities with Contingent Resources, and a portfolio of Prospective Resources. **Tables ES1 to ES6** below provide a summary of the Reserves and Resources gross and net to Seven Energy and the economic evaluation results for these assets as determined by LR.

Seven Energy Licence Interests						
Asset	Operator	Participating Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
Uquo	FOL	40%	Production	2026	171 sqkm	Fee due
Stubb Creek	UERL	31.9%[2]	Production	2026	42 sqkm	Fee due

Table ES1: Seven Energy Licence Interests[3]

LR understands: (1) that both the Uquo JV and the Stubb Creek JV are due to pay licence renewal fees of US$1MM to the DPR which are expected to be paid as part of the licence transfer process; and (2) the overall transaction is subject to Nigerian Ministerial consent which would re-validate and transfer legal title of these assets from subsidiaries of Seven Energy International Limited to subsidiaries of Savannah Petroleum plc. In assessing Reserves and Resources, LR has assumed, based on its general experience in licence valuations and pursuant to the relevant Marginal Field Guidelines, that the Nigerian Government will renew the licences beyond the current licence expiry dates while there remain Reserves.

Seven Energy also owns the Accugas Limited (Accugas) midstream business. LR is informed that concurrent with the acquisition of the Seven interest, Savannah is negotiating to retain a 20% minority interest in the entity, the remaining interest to be divested to one or more private equity investors. Accugas focuses on the sale, marketing and distribution of gas to the domestic Nigerian market, and comprises the 200 MMscf/d Uquo gas processing facility, a c.260 km pipeline network and long-term gas sales agreements (GSAs) with downstream customers. LR has reviewed an assessment of the base case NPV10 of the Accugas business which computes a gross US$1,045MM value, implying a value net to a 20% interest of US$209MM.

[2] Represents Seven Energy's 62.5% interest in UERL which has a 51% interest in the licence.

[3] The licence expiry dates refer to the current period.

Remaining Recoverable Volumes, Reserves and Resources

The recoverable volumes presented in this report are an update to LR's review and assessment of the interpretations by Seven Energy, Savannah and associated independent consultants conducted on the assets in 2015 and 2017. In the period 2015 to 2017, LR has critically reviewed all the available data, interpretations and methodologies employed and has followed good petroleum practices in its assessment of the volume estimations of in-place and recoverable hydrocarbons, and of the valuation of each of the assets. In the case of in-place volumes, where Seven Energy and Savannah have confirmed that there is no new data or subsurface interpretations which would materially affect the valuation of the assets, LR have adopted the most recent prior assessed volumes.

The gross recoverable volumes for the low, best and high cases for the fields are derived variously by volumetric estimation, decline curve analysis, material balance analysis, and reservoir simulation. The net attributable Reserves and Contingent Resources to Seven Energy have been derived by applying the Savannah economic model to compute net entitlements compliant with PRMS guidelines.

Reserves

In the South East Niger Delta, both the Uquo and Stubb Creek Marginal Fields are in production.

The net Reserves attributable to Seven Energy are the net entitlement volumes before deduction of any taxes and royalties. They have been derived by applying the terms of the Joint Venture, licence agreements and other contracts within the Savannah economic model which conform to PRMS guidelines. Gross and net Reserves attributable to Seven Energy as at 1st November 2017 are summarised in **Table ES2** below:

Oil and Gas Reserves							
	Gross on Licence			Net Attributable			
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	Operator
Oil & Liquids Reserves (MMstb)							
Uquo	4.2	7.8	12.4	3.5	6.7	9.0	FOL
Stubb Creek	9.6	17.1	26.7	1.3	2.5	4.2	UERL
Total Oil & Liquids, MMstb	**13.8**	**24.9**	**39.1**	**4.8**	**9.2**	**13.2**	
Gas Reserves (Bscf)							
Uquo	364.5	565.0	788.1	319.7	495.5	634.3	FOL
Total Gas, Bscf	**364.5**	**565.0**	**788.1**	**319.7**	**495.5**	**634.3**	

Table ES2: Oil and Gas Reserves[4]

[4] 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. 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. Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recoverable than Probable Reserves. Net attributable volumes are quoted before deduction of tax and royalty equivalent volumes.

Totals have been arithmetically summed. This method of summation is recommended under PRMS guidelines and results in conservative low case and optimistic high case totals. Totals may not add exactly due to rounding.

Net: the portion of the gross reserves that are attributed to the equity interests to be acquired by Savannah.

Contingent Resources

The gas field located in the Stubb Creek Marginal Field licence area is intended to be developed once the Uquo field comes off plateau in order to meet Gas Sale Agreement (GSA) requirements. The overall risk factor/ chance of commerciality is estimated at some 75% to reflect the limited technical risk and remaining commercial risk.

There are discovered reservoirs in the licenced areas of the South East Niger Delta Assets that are not included in the approved FDPs and, hence, constitute part of the Contingent Resources. The net Contingent Resources attributable to Seven Energy are the net entitlement volumes before deduction of any taxes and royalties. The Contingent Resource volume estimates are:

Oil and Gas Contingent Resources								
	Gross on Licence			Net Attributable				
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Risk Factor	Operator
Oil & Liquids Resources (MMstb)								
Uquo	1.0	2.5	5.1	0.9	2.1	3.0	25-75%	FOL
Stubb Creek	0.7	1.0	1.4	0.1	0.2	0.3	>75%	UERL
Total Oil & Liquids, MMstb	**1.7**	**3.5**	**6.5**	**1.0**	**2.3**	**3.3**		
Gas Resources (Bscf)								
Uquo	45.0	72.5	115.6	39.5	63.6	79.6	>75%	FOL
Stubb Creek[5]	364.9	515.3	680.3	129.4	184.3	238.1	>75%	UERL
Total Gas, Bscf	**409.9**	**587.8**	**795.9**	**168.9**	**247.9**	**317.7**		

Table ES3: Oil and Gas Contingent Resources[6]

[5] Stubb Creek 3C gas contingent resources includes volumes expected to be produced after 2040 (cf. Tables A5 and A6).

[6] 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. They are the volumes that are technically recoverable from DPIIP (discovered petroleum initially in place) under defined projects that are expected to become commercial upon resolution of contingencies. Net Attributable is the net entitlement volume potentially accruing to Seven Energy calculated by applying the terms of the current Joint Venture Agreements and existing sales agreements. Net attributable volumes are quoted before deduction of tax and royalty equivalent volumes.

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

Prospective Resources

Uquo

There is exploration potential in the Uquo Marginal Field licence area in the South East Niger Delta (Section 3.1). The summed, unrisked volumetric estimates for Prospective Resources are summarised below. The individual gross volumes are described in Section 3.1.6 and tabulated therein.

LR was previously informed by Seven Energy that Frontier Oil Limited (FOL), as operator of the Uquo Marginal Field, obtained permission on 5th May 2015 from the Department of Petroleum Resources (DPR) to extend the Uquo Marginal Field boundary to incorporate practically all the identified prospects.

Volumes net attributable to Seven Energy for Prospective Resources have been estimated from the reported gross volumes (Section 3.1.6) by using the ratios calculated for Contingent Resources.

The Prospective Resource volume estimates are:

Gas Prospective Resources								
	Gross on Licence			Net Attributable				
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Risk Factor	Operator
Gas Resources (Bscf)								
Uquo[7]	390.6	578.8	860.2	342.6	507.6	592.3	25-75%	FOL
Total Gas, Bscf	**390.6**	**578.8**	**860.2**	**342.6**	**507.6**	**592.3**		

Table ES4: Gas Prospective Resources[8]

Economic Valuation

A detailed economic model provided by Savannah, and reviewed by LR, was used to carry out a valuation as described in Section 4 of this report. This model uses the gross field volumes and the volume distribution ranges for the Reserves for each producing field or discovery. The NPV calculations throughout include accounting for taxes and royalties.

Reserves

The portfolio was valued using the economic model provided by Savannah. LR audited the model and found it to reflect the relevant fiscal and commercial terms accurately (as shown in **Table 4.1**), as well as the relevant capital costs, operating costs and production rates. The production forecasts were derived by LR after due consideration of the fields' potential

[7] Arithmetic sum of 10 separate prospects

[8] Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations. Gross Prospective Resources are the volumes expected to be recovered from UPIIP (undiscovered petroleum initially in place) under conceptual projects, conditional on discovery and development. Net Attributable is the volume which would potentially accrue to Seven Energy by application of the current Joint Venture Agreement terms to such potential future projects. The ultimate realised Net entitlement will depend on the contractual terms of the licence at the time of any eventual hydrocarbon production and the associated cost and profit structures. No economic cut offs have been applied.

"Risk Factor" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource.

Volumes in Table ES4 are Unrisked numbers.

and individual field forward plans and LR's assessment of future well performance. Historical capital and operating costs were assessed in the determination of future likely costs for the development scenarios, and LR found the future capital and operating costs provided by Savannah and Seven Energy to be reasonable (see Section 4.1.1).

Production profiles have been prepared for the Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves and the Low, Best and High Contingent Resources categories. Reserves profiles were curtailed at the limit of economic production. These profiles make assumptions related to the success of future operations and delivery of projects in accordance with the operator's current plans.

Estimates of the NPV of future net cashflows from Reserves volumes after deduction of taxes and royalties deriving from the Seven Energy share as of 1st November 2017 are presented below.

NPV10[9] (US$MM) for Reserves Net to Seven Energy			
	Proved	**Proved + Probable**	**Proved + Probable + Possible**
South East Niger Delta:			
Uquo liquids	61.1	103.1	141.3
Uquo gas	261.0	397.3	494.6
Stubb Creek oil	26.1	47.6	55.3
Total NPV10* (US$MM)	**348.2**	**548.0**	**691.2**

*Note that the totals may not sum exactly due to rounding.

Table ES5: NPV10 for Reserves Net to Seven Energy

A Proved plus Probable sensitivity analysis is shown below:

NPV10 (US$MM) Net to Seven Energy			
	Proved + Probable		
	US$50/bbl	**Base Case (US$60/bbl)**	**US$70/bbl**
South East Niger Delta:			
Uquo liquids & gas	480.6	500.4	519.1
Stubb Creek oil	39.1	47.6	53.0
Total NPV10 (US$MM)	**519.7**	**548.0**	**572.1**

Table ES6: Proved+Probable NPV Sensitivity to Oil Price

[9] NPV: Net Present Value after deduction of Taxes and Royalties at a 10% discount rate. See Section 4.

Totals do not take account of dependencies and have been arithmetically summed. This method of summation is recommended under PRMS guidelines and results in conservative low case and optimistic high case totals. Totals may not add exactly due to rounding.

Proved + Probable Upstream Portfolio Sensitivity to oil price

The Proved + Probable Upstream portfolio value was run with a range of oil prices. The corresponding values are shown in the graph below:

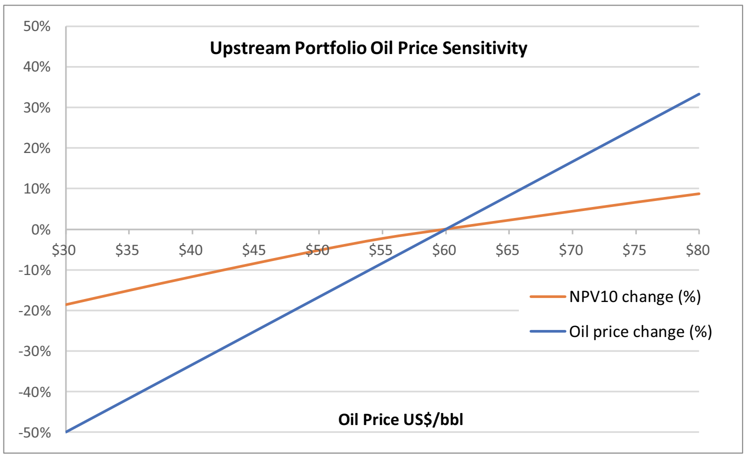


Figure ES1: Proved + Probable Upstream Portfolio Sensitivity to Oil Price

Production Profiles

LR has constructed gross production profiles for the Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves, and Low, Best and High Contingent Resources. Net production profiles are derived from the economic model. Tables A.1 to A.6 and Figures A.1 to A.3 show consolidated and field profiles for the portfolios of assets in the licence areas.

Reconciliation to last Historic Statement

LR is not aware of any previous reporting of the resource potential of these assets to the AIM market of the London Stock Exchange.

Professional Qualifications

Lloyd’s Register (LR) is a global engineering, technical and business services organisation wholly owned by the Lloyd’s Register Foundation, a UK charity dedicated to research and education in science and engineering. Founded in 1760 as a marine classification society, LR now operates across many industry sectors, with over 9,000 employees based in 78 countries.

In September 2013, Senergy became a member of the LR Group following an agreement for LR to take a significant investment in the company. Together, we are sharing our global knowledge and technical excellence that has been accrued over decades, yet listening to our clients and letting them help shape the future of our services. Together we are providing a broader service portfolio to the upstream sector of the energy industry, from reservoir to refinery and beyond.

Our parent entity, Lloyd’s Register Foundation, is a charity, with a mission to fund education and science, engineering and technology research for public benefit worldwide.

As the operating company, LR generates the profits that help to fund the organisation’s public benefit activities. We are proud that our compliance, risk and technical consultancy services also directly support a significant part of the Foundation’s charitable objectives - to enhance the safety of life, property and the environment - by helping our clients to ensure the quality construction and operation of critical infrastructure.

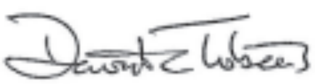
Study work completed in LR’s offices was performed and controlled according to Lloyd’s Register quality procedures, established to ensure that products are delivered on time, within budget, and meeting the defined objectives. All LR personnel adhere to these procedures as defined within our management system which is registered to the international quality standards ISO 9001, ISO 14001, OHSAS 18001 and PAS 99. Except for the provision of professional services on a fee basis, LR has no commercial arrangement with any person or company involved in the interest that is the subject of this report.

Allan Spencer is a Principal Reservoir Engineer for LR and was responsible for this evaluation. He is a professional reservoir engineer with over 25 years of oil industry experience gained in international companies, consultancy companies and within LR. He is a member of the Society of Petroleum Engineers and is an accredited Reserves Auditor.

David Tobias is a Commercial Project Manager in LR’s Reserves and Asset Evaluation group and was responsible for supervising this evaluation. He is a professional petroleum geologist with over 25 years of oil industry experience gained in international companies, consultancy companies and within LR. He is a Fellow of the Geological Society, a member of the Petroleum Exploration Society of Great Britain and has a B.Sc. in Geology from the University of Manchester, an MSc in Marine Geotechnics from the University of North Wales and an MBA from the UK Open University.

Other members of LR staff involved in this work hold at least a degree in geology, geophysics, petroleum engineering or related subjects and/or have at least five years of relevant experience in the practice of geology, geophysics or petroleum engineering.

Yours faithfully,



David Tobias

For and on behalf of Lloyd’s Register

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1. Introduction

This report was prepared by Senergy (GB) Limited (Lloyd's Register or LR) in December 2017 at the direction of the Directors of Savannah Petroleum plc (Savannah), Strand Hanson Limited and Barclays Bank plc (Barclays Bank). It consists of an evaluation carried out between August and December 2017 of the interests held by Seven Energy International Limited (Seven Energy) and its subsidiary companies, together known as the (Group) in Uquo and Stubb Creek Marginal Fields onshore Nigeria (see infrastructure map **Figure 1.1**).

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

LR was requested to provide an independent evaluation of the recoverable hydrocarbons and an economic valuation for each asset. The report details the licence and economic interests owned by Seven Energy, and the Reserves, Contingent Resources, and Prospective Resources attributable to the assets, and economic valuations for the Reserves, Resources and related infrastructure.

1.1 Legal Overview, Licence and Environmental Details

Table 1.1 details the licences held by Seven Energy in Nigeria and evaluated by LR as at 1st November 2017.

Seven Energy Licence Interests						
Asset	Operator	Participating Interest (%)	Status	Licence Expiry Date	Licence Area	Comments
Uquo	FOL	40%	Production	2026	171 sqkm	Fee due
Stubb Creek	UERL	31.9%[10]	Production	2026	42 sqkm	Fee due

Table 1.1: Seven Energy Licence Interests[11]

The licence details were supplied by Seven Energy and are believed to be valid at the effective date of this report. LR has not reviewed the legal status and licence documents and hence does not make any statement as to the ownership, contractual or legal terms of these licences. LR understands: (1) that both the Uquo JV and the Stubb Creek JV are due to pay licence renewal fees of US$1MM to the DPR which are expected to be paid as part of the licence transfer process; and (2) the overall transaction is subject to Nigerian Ministerial consent which would re-validate and transfer legal title of these assets from subsidiaries of Seven Energy International Limited to subsidiaries of Savannah Petroleum plc. In assessing Reserves and Resources, LR has assumed, based on its general experience in licence valuations and pursuant to the relevant Marginal Field Guidelines, that the Nigerian Government will renew the licences beyond the current licence expiry dates while there remain Reserves. Further information on the licence has been provided in Section 4.

1.2 Sources of Information

In conducting this review, LR has used information and interpretations supplied by Savannah and Seven Energy which comprised operator information and geological, geophysical, engineering and other data along with various technical reports. The information provided has been reviewed and assumptions modified where deemed appropriate.

[10] Represents Seven Energy's 62.5% interest in UERL which has a 51% interest in the licence.

[11] The licence expiry dates refer to the current period.

The database available for each asset is described in more detail in the field description sections of the body of this report. A site visit had not been conducted by LR as of the date of this report. However, LR were informed that Savannah and Strand Hanson visited the Uquo and Stubb Creek Marginal Fields and Accugas Processing Facilities.

1.3 Evaluation Methodology

LR was requested to provide an independent evaluation of the recoverable hydrocarbons expected for each asset. The starting point in assessing Reserves or Resources is an estimate of Hydrocarbons-Initially-In-Place (HCIIP). Various methods may be used, and in this report the quoted Low, Best and High HCIIP volumes are a mixture of deterministic and probabilistic estimates calculated by the operator, Savannah, Seven Energy and LR.

The specific LR methods used for calculating HCIIP are based on good industry practices but it should be emphasised that there is no single universally accepted method in use within the industry. Probabilistic estimates are generated using a ”Monte Carlo” statistical approach. For probabilistic estimates, the Low is P90, the Best is P50 and the High is P10. A resource size distribution is determined by the size ranges of its input parameters and the probability distribution applied to each input (e.g. whether normal, lognormal or other). The size range of the calculated resource distribution is particularly sensitive to the choice of ‘end member’ P90 and P10 (i.e. 90 and 10% probability) input parameters especially for the key inputs of assumed hydrocarbon contact depth and reservoir thickness.

Standard geological and engineering techniques accepted by the petroleum industry were used in estimating recoverable hydrocarbons. These techniques rely on engineering and geo-scientific interpretation and judgment; hence the Resources included in this evaluation are estimates and should not be construed to be exact quantities. It should be recognised that such estimates of hydrocarbon Resources may increase or decrease in future if there are changes to the technical interpretation, economic criteria or regulatory requirements. LR has estimated the degree of uncertainty inherent in the measurements and interpretation of the data and has calculated a range of recoverable Reserves. The probabilistic estimates of recoverable volumes are generated using a ”Monte Carlo” statistical approach. Therefore, it is not correct to back calculate Recovery Factors for any specific case (Low, Best or High), or summation of cases, from the HCIIP and recoverable volumes reported for that case.

Savannah and Seven Energy provided LR with seismic data, models and interpretations, and log interpretations to perform an independent HCIIP volumetric distribution estimate for each of the fields. Quality control of seismic interpretation was carried out on all assets, to assess the level of confidence to be placed in volumes ascribed to assets and to indicate where any significant alternative view of the interpretation might be possible. Specific comments and variations in conclusions on each of the assets are detailed in the ensuing sections.

The Reserve or Resource volumes can also be estimated using a variety of methods. In this report, the Reserves and Resources are estimated using material balance, simulation and analytical models. An assessment of the resulting recovery factors was deemed by LR to be reasonable in the context of the Niger Delta Basin.

1.4 Requirements

In accordance with Savannah, Strand Hanson and Barclay Bank’s instructions, LR confirms that:

– It is professionally qualified and a member in good standing of self-regulatory organisations of engineers and geoscientists;

– It complies with the relevant standards for Reserves estimators and auditors as described in “Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information”, approved by the SPE Board and revised February 2007;

– It is independent of Savannah and of Seven Energy, their directors, senior management and advisers, and has no interest in any of the assets of Savannah or Seven Energy or their subsidiaries;

- It will be remunerated by way of a time-based fee and not by way of a fee that is linked to the value of Savannah or Seven Energy;
- LR has the relevant and appropriate qualifications, experience and technical knowledge to professionally and independently appraise the assets, being all assets, licences, joint ventures or other arrangements owned by Seven Energy or proposed to be exploited or utilised by it (Assets) and liabilities, being all liabilities, Royalty payments, contractual agreements and minimum funding requirements relating to the Group's work programme and Assets (Liabilities);
- LR is experienced in the provision of independent "Competent Person's" and Reserve reports, and has conducted evaluations in compliance with the London Stock Exchange AIM rules, Australian and Toronto Stock Exchanges and Norwegian Rules for clients and financial institutions.

1.5 Standards Applied

In compiling this report, LR has used the definitions and guidelines set out in the 2007 Petroleum Resources Management System (PRMS) 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) (see Section 5), and the requirements of the Prospectus Rules of the Financial Conduct Authority, and having regard to the recommendations for the consistent implementation of the European Commission's Regulation on Prospectuses No. 809/2004 published by the Committee of European Securities Regulators (CESR), as updated by the European Securities and Markets Authority in March 2011 (the ESMA Guidance) and, in particular, paragraphs 131 to 133 inclusive of the ESMA Guidance.

1.6 Liability

All interpretations and conclusions presented herein are opinions based on inferences from geological, geophysical, engineering or other data. The report represents LR's best professional judgment and should not be considered a guarantee of results.

1.7 Consent

LR hereby consents, and has not revoked such consent, to:

- the inclusion of this report, and a summary of portions of this report, in documents prepared by Savannah and its advisers;
- the filing of this report with any stock exchange and other regulatory authority;
- the provision of this report to Savannah's lenders in connection with any financing or its debt facilities;
- the electronic publication of this report on websites accessible by the public, including a website of Savannah;
- the inclusion of LR's name in documents prepared in connection with commercial or financial activities.

The report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The report must therefore, be read in its entirety. This report was provided for the use of Savannah on a fee basis. Except with permission from LR this report may not be reproduced or redistributed, in whole or in part, to any other person or published for any other purpose than specified above without the express written consent of LR.

Particularly, LR has given and not withdrawn its written consent to inclusion of our name, this report and references to this report in an Admission Document which may be issued by Savannah in connection with the issue of securities and the listing of such securities on the AIM market of the London Stock Exchange. LR declares that, to the best of its knowledge and belief, having taken all reasonable care to ensure that such is the case, the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. Regional Aspects

The Seven Energy interests evaluated are located onshore in the South East of the prolific Niger Delta petroleum system (**Figure 2.1**) in Southern Nigeria. In addition to its high ranking world petroleum status, with some 37.1 billion barrels of oil reserves as of end 2016 (11^{th} largest in the world), Nigeria has the largest gas Resources in the African continent with some 186.6 trillion cubic feet reserves (BP Statistical Review of World Energy, June 2017), and these have remained largely unexploited. Associated gas has traditionally been flared in the absence of any developed gas market but policy and economic development is now moving rapidly towards a favourable climate for gas commercialisation.

The government has put in place legislation to reduce flaring, originally with a target of zero flaring by end 2009, which has not been met. Penalties for flaring are now imposed and will increase in cost in coming years, and new oil field developments will have to have zero flaring.

Nigeria's GDP growth averaged 8.6% from 2000 to 2012 but shrank to an average of just under 1% per year in the period 2013-17. There are chronic domestic power shortages in Nigeria due largely to lack of infrastructure and under investment reducing generating power from an estimated potential capacity in excess of 10 gigawatts to the current level of around 2.5 to 3 gigawatts. The Federal Government Gas Master Plan aims to unlock Nigeria's natural gas potential to alleviate the power supply shortage and meet the country's growing energy demand. The Government is seeking to implement power sector reforms and views domestic gas utilisation as vital to solving the power supply problem.

Seven Energy's average sales price via its existing contracts is significantly lower than the cost of diesel to generate electricity. Economically, there is an incentive to switch from diesel to gas while over the longer term the price of gas is expected to increase as the market develops.

LR has not conducted a regional evaluation as part of this review but relevant aspects are noted below to provide context and background to the individual asset assessments.

2.1 Regional Geological Setting

The Niger Delta Basin is an internationally recognised, mature petroleum province located on the West African margin and underlies the coastal plain, shelf and slope. The Niger Delta Basin is mature in terms of drilling and seismic density and extremely prospective in terms of hydrocarbons discovered. Late Jurassic to Early Cretaceous rifting controlled initial development of the delta and its main depocentre. The Niger Delta Basin has been prograding south-westwards since Eocene times (ca. 55 Ma). The Tertiary age Niger Delta covers an area of about 75,000 km^2 and has a sedimentary thickness of up to 10,000 m.

The assets studied in this report, located in the south-eastern part of the Niger Delta Basin (**Figure 2.1**), are dominated by normal faults trending northwest to southeast. Traps are present in a variety of combinations of rollover structures with different faulting styles.

The Miocene Agbada Formation is the principal petroleum bearing formation in the Niger Delta Basin and contains multiple hydrocarbon bearing units interbedded with extensive Agbada mudstones, which form seals to the reservoirs (**Figure 2.2**). Reservoir sands are predominantly thick (of the order of 10 to 50 m) with excellent reservoir quality and generally have good lateral continuity. The interbedded mudstones are frequently thick and form good seals against faults. Sufficient burial of the pro-delta, marine shales of the Akata Formation has allowed maturation for oil and gas generation, and these provide prolific source rocks to the area providing light, paraffinic crude.

2.2 Reservoir Horizons and Petrophysics

As noted above, the main reservoir interval in the fields reviewed is the Agbada sands of Miocene age. The database includes work that is based primarily on log analysis and correlation as there is very little relevant core material. In general, the lower delta plain to shallow marine facies comprise the best reservoir intervals. The latter are likely to be more laterally extensive and better connected.

The reservoir descriptions and position of hydrocarbon contacts rely mostly on log analysis and the petrophysical assessments are often subject to uncertainty as a result of log data quality limitations, lack of core material, complex mineralogy and variable water resistivity. LR has taken into consideration any uncertainty in the range of reservoir parameters and hydrocarbon contacts in its review of HCIIP estimates.

2.3 Seismic Database

The seismic database over the fields comprises mixed vintages of 2D and 3D seismic data. IHS Kingdom projects, in all cases containing the relevant seismic database and well data, were provided for each of the asset areas for assessment by LR.

The Uquo Marginal Field and the surrounding area is covered by a 3D survey acquired in 2006-2007. Data quality is good.

The Stubb Creek field is covered by a 3D seismic survey acquired in 2005/06 by Universal Energy Resources Limited (UERL). Data quality is excellent, allowing accurate structural mapping, and identification of amplitude anomalies related to hydrocarbon distribution.

2.4 Engineering Data and Interpretation

Historically, estimates of hydrocarbons in place and ultimate recovery have used volumetric methods, material balance and reservoir simulation. In most cases, the uncertainty around in-place volumes dominate the overall uncertainty in Reserves or Resources. There is uncertainty associated with the geoscience and engineering data. There is also regional evidence of active aquifer support in most sands which generally results in low pressure decline throughout fields' production. These factors have been considered in the assessments of Reserves and Resources by LR.

In this report, gas volumes are reported in billions of standard cubic feet (Bscf), condensate and oil volumes in millions of stock tank barrels (MMstb).

2.5 Asset Operatorship

Seven Energy holds a 40% participating interest in the Uquo Marginal Field via its 100% owned subsidiary Seven Uquo Gas Limited (SUGL). The remaining 60% participating interest in the Uquo Marginal Field is held by Frontier Oil Limited (FOL). FOL is the operator of the Uquo Marginal Field but is supported in this role by SUGL which acts as FOL's technical partner pursuant to a technical services agreement entered into by FOL and SUGL.

Seven Energy's 62.5% interest in subsidiary Universal Energy Resources Limited (UERL) which in turn holds a 51% participating interest in the Stubb Creek Marginal Field, implies a participating interest net to Seven Energy of 31.9%. The remaining 49% participating interest in the Stubb Creek Marginal Field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited (SIPEC). UERL is the operator of Stubb Creek Marginal Field.

3. South East Niger Delta Assets

3.1 Uquo Marginal Field

3.1.1 Summary

The Uquo Marginal Field is located onshore in OML 13 in Akwa Ibom State, South East Niger Delta, some 8 km from Mobil's Qua Iboe oil terminal (**Figure 1.1**). The field, together with several associated prospects, is contained within the Uquo Marginal Field licence area. Frontier Oil Limited (FOL) is the operator and Seven Uquo Gas Limited (SUGL), a wholly owned subsidiary of Seven Energy, is FOL's technical and financing partner and holds a 40% participating interest in the Uquo Marginal Field. LR are informed that on 5th May 2015, the Department of Petroleum Resources (DPR) granted an extension to the Uquo Marginal Field licence area which increases the resource volumes within the enlarged licence for the Uquo NE discovery and, to some extent, for the Uquo South and Uquo East prospects (**Figure 3.1**).

The field was discovered by Shell Development Petroleum Company Nigeria Limited (SPDC) in 1958 by the Uquo-1 well, which found oil and gas in four sands between 6,800 and 8,000 ft tvdss, in the Tertiary Agbada Formation.

Three appraisal wells were drilled in 1971/2 on structural highs and all encountered gas bearing sands. A fifth well, drilled in 2008, twinned Uquo-1 and encountered gas but did not confirm the oil reported in the discovery well. This well was side-tracked as Uquo-6, but progress was curtailed by mechanical failure before reaching the oil-bearing zone. In January 2010, Uquo-3 was worked over and completed as an oil producer. In April 2010 and May 2013, Uquo-2 and Uquo-4 were completed as gas producers respectively. Two development/appraisal wells, Uquo-7, -8/8ST were drilled from the Uquo-3 surface location between June to September 2013. The Uquo-7 and Uquo-8ST wells were then completed in 2014 as gas producers. The appraisal/exploration well Uquo-9 was spudded in November 2014 on the Uquo NE prospect, which lies to the northeast of Uquo-1 in a separate fault compartment (**Figure 3.1**). The well was sidetracked as Uquo-9ST and suspended as an oil and gas discovery.

The field was initially evaluated in 2005 using 2D seismic, and a 3D survey was acquired during 2006 and 2007. This survey covers most of the concession but does not extend to the western edge of the it, due to the presence of an airfield which limited access. Data quality is good and allows accurate structural mapping of the reservoirs, although frequency content is too low to allow accurate stratigraphic interpretations. Seismic amplitude anomalies and flat spots are clearly identifiable and have been used, together with seismic attribute volumes, as an aid to constrain areas of closure and reduce the risk of definition of in-place hydrocarbon volumes.

An evaluation of the field in 2012 produced a comprehensive series of structure and attribute maps for the key reservoir sands, which were used for subsequent volumetric calculations. Reasonable limits were imposed on the areas regarded as containing reserves, recognising stratigraphic trapping uncertainty.

In 2017 Savannah provided interpretation material relating to some additional studies that they carried out in their assessment of the Uquo Marginal Field. LR have assessed the impact or otherwise of these studies on the volumetric in place estimates previously carried out by LR for Seven Energy and have updated the numbers herein where appropriate.

3.1.2 Subsurface Description

The Uquo Marginal Field lies within a gently folded area, which is aligned east-west and fault-bounded to the north and south. There are four structural culminations in the fault block, two in the north (Uquo-2/4 and 5 areas) which are dip-bounded, and two dip and fault-closed structures in the south (Uquo-3 area) and Uquo NE areas. The field is defined by four vertical wells, Uquo-1, -2, -3, -5 and five deviated wells, Uquo-4, -7, -8, -8ST, -9 plus Uquo-6, a side track of Uquo-5 and Uquo-9ST, a sidetrack of Uquo-9. These have proved four separate structures, with 19 hydrocarbon bearing reservoirs (14 gas bearing, 4 proven oil-bearing and one potentially oil-bearing), all of which lie within the Early Miocene Agbada Formation (**Figure 3.2**).

The discovery well drilled in 1958 found two oil-bearing formations (D1.5 and U5.0) in the east of the field both of which were tested. Further drilling was conducted in 1971/72, when three more wells were completed (two exploration wells and one appraisal well). This campaign identified another 10 gas-bearing formations and one potentially oil-bearing formation. Uquo-5, was drilled in 2008, as a twin of Uquo-1 to further evaluate the oil discovery. The oil volumes proved smaller than anticipated, and the well was subsequently sidetracked. This sidetrack confirmed gas in one reservoir (C8.5). Seven Energy believes that there is uncertainty in this area due to possible inaccuracies in well deviation surveys and seismic data that were corrupted by diffracted energy related to the close proximity of major faulting. The wells (Uquo-7, -8 and -8ST) drilled in 2013, have appraised the D1.0, D1.3 / D1.4 gas and D5.0 oil sands. In 2014/2015, an exploration well (Uquo-9) was drilled to evaluate a major amplitude anomaly associated with the C6 level (**Figure 3.3)**. However, closure of the prospect was not defined to the east due to lack of seismic data. Uquo-9/9ST found gas in the C6,0, D1.0, D1.5 and oil in the D1.6 and D7.0 sands.

The field is mostly covered by a 133 km^2 3D seismic survey, acquired in 2006 - 2007. 2D seismic coverage here is limited to twenty-eight older 2D lines which are of limited quality. A detailed seismic interpretation of the 3D data was completed in by Seven Energy (**Figure 3.4**), and a series of depth and attribute maps were produced. The SW - NE seismic cross section clearly shows the amplitude enhancement associated with hydrocarbon presence at several reservoir zones, with listric faulting and associated rollover structural trap geometry typical of the region.

For volumetric purposes, the field has been divided into four areas: the Uquo-3 area in the south (Reservoirs D1.0, D1.3, D1.4 and D5.0), the Uquo-2/4 area in the north (Reservoirs C9.0, D1.0, D1.3, D1.4, D1.5, D2.0 and D5.0), the Uquo-5 area, which has proven oil in the U5.0 and gas in the C8.5 reservoir only, and the Uquo NE area (reservoirs C6.0, D1.0, D1.5, D1.6 and D7.0).

Figure 3.5 is an Uquo main field schematic through faulted segments including the main field.

As part of its evaluation in late 2012, Seven Energy / FOL conducted a detailed review of five prospects (NE, 1SE, 3E, 3S and 1N) from ten exploration targets originally identified in 2008, with the aim of fixing targets for future drilling campaigns. The Uquo NE prospect, which lies to the northeast of Uquo-1 in a separate fault compartment, was drilled and logged in 2014 / 2015, as mentioned in Section 3.1.1 above. The other prospects are described in Section 3.1.6 below.

The database provided was reviewed by LR and included a Kingdom project, containing the 3D seismic data, and some of the 2D lines, as well as available log data and tops for the producing sands. The 3D data were found to be of good quality and the structure of the field could be defined with confidence, although the frequency content, and consequently the vertical resolution, was found to be low (apparent dominant frequency below 30 Hz) given the relatively thin hydrocarbon bearing intervals. If there is a significant stratigraphic element to the trapping, this was believed likely to go undetected.

In addition, as also evident on seismic lines examined by LR in 2017, amplitude anomalies relating to hydrocarbon accumulations are clearly visible and correlate in general terms with structural culminations and closure (**Figures 3.6**). Apart from the bounding faults, the field is free of major faulting, but minor antithetic faulting is present over the Uquo-2/4 area in the north, and synthetic faulting may be present over the Uquo-3 area in the south. It is also clear from the 3D data that amplitude anomalies are present in layers above the currently recognised reservoirs, particularly adjacent to the fault in the north, and the northeast of the area.

Overall, reservoir quality is excellent with average porosities of net sand around 30% and permeabilities determined by well test analysis of the order of 1 Darcy.

3.1.3 Hydrocarbons-Initially-in-Place

The Gas-Initially-In-Place (GIIP) estimates made have been subdivided into the two main areas of the field; namely Uquo-2/4 and Uquo-3 together with the Uquo NE area. The main uncertainty in the estimation of the GIIP is in the GWC depths, which have been evaluated according to the different fluid contacts encountered in each culmination, seismic amplitude fill indications and structural spill points. Seven Energy / FOL reassessed the GIIP for Uquo in 2012/2013.

Savannah's 2017 interpretation of the seismic in the Uquo-3 area, south of the southern east-west trending bounding fault concludes limited opportunity for gas south of the fault. LR examined pdf copies of seismic attribute processed lines in the Uquo-3 area in 2017 to assess if gas resources can be interpreted to lie south of the southern east-west trending bounding fault with reasonable certainty and concluded that available seismic data does not appear to provide an unambiguous interpretation of the fault pattern. LR also reviewed and support the 2017 Savannah interpretation. Accordingly, gas resources potentially lying South of this bounding fault have been classified as prospective resources (c.f. Section 3.1.6 - Uquo 3 fault zone prospect). LR note that the faulting in the Uquo-3 area could affect the deeper imaging and recommend that data in this area have full pre-stack depth migration to improve the imaging and possibly reveal deeper amplitude anomalies of oil prospective sands.

LR examined the probabilistic volume estimates in the Uquo NE Area. LR note that the current 3D seismic area eastern extent coincides with the current license boundary. The mapped surface also carries large uncertainty in the region of the off license Etebi-1 well as it has no seismic coverage. Another uncertainty is the sand distribution and quality between the lower NTG Uquo-9 and the Etebi-1 well, which has a thicker and better quality C6.0 reservoir (**Figure 3.7**). A final important uncertainty which is more difficult to evaluate is the GRV split between the on and off license areas between these two wells. At this stage, an equal split between the two regions for GRV has been applied and a NTG range from 0.4-0.9 used.

HCIIP estimates from Seven Energy and Savannah have been reviewed by LR and are included in **Tables 3.1, 3.2 and 3.3**.

Gross GIIP (Bscf)		Low	Best	High
Uquo-2/4 Area	D1.0	183.2	216.3	254.8
	D1.3/D1.4	74.3	94.9	118.5
	D2.0	108.9	134.1	163.9
	D5.0	17.1	30.1	46.7
Sub-total		383.5	475.4	583.9
Uquo-3 Area	D1.0	107.0	204.0	300.0
	D1.3/D1.4	22.0	34.5	48.6
Sub-total		129.0	238.5	348.6
Uquo NE Area*	C6.0	80.0	99.8	124.0
Total		**592.5**	**813.7**	**1,056.5**

*Note that Uquo NE volumes are on-licence only.

Table 3.1: Uquo Marginal Field: GIIP

Uquo-3 was re-entered in 2009/10 and successfully tested the D5.0 oil sand. The stock-tank-oil-initially-in-place (STOIIP) for the D5.0 reservoir was re-assessed by Seven Energy / FOL subsequent to the 2013 drilling of the Uquo-7 and Uquo-8 wells.

Uquo-9/9ST (Uquo NE) was drilled in 2014 and recovered oil from the D1.6 and D7.0 sands. Subsequent to the drilling of the well, Seven Energy assessed the STOIIP for the reservoirs, as tabulated below. Note that the D7.0 reservoir is deep and will require a new well for optimal recovery. Accordingly, LR has assessed the D7.0 reservoir as containing Contingent Resources.

Gross STOIIP (MMstb)		Low	Best	High
Uquo-3 Area	D5.0	2.4	5.5	9.4
Sub-total		2.4	5.5	9.4
Uquo NE Area	D1.6	9.6	14.4	20.2
	D7.0	3.6	7.0	11.3
Sub-total		13.2	21.4	31.5
Total		**15.6**	**26.9**	**40.9**

Table 3.2: Uquo Marginal Field: STOIIP

In the Uquo NE area, LR have made the estimate based on the modelled GRV which is fully on the licence. Volumes have also been estimated for two reservoirs (C8.5 and C9.0) where gas has been encountered, but the current development plans do not include production from these horizons (as tabulated below).

Gross GIIP (Bscf)		Low	Best	High
Uquo NE Area	D1.0	27.3	40.4	55.6
	D1.5	2.8	4.2	6.1
Sub-total		30.1	44.6	61.7
Uquo-5 Area	C8.5	11.0	14.3	18.6
Uquo-2/4 Area	C9.0	17.3	35.9	65.8
Total		**58.4**	**94.8**	**146.1**

Table 3.3: Uquo Marginal Field: GIIP (excluded from development plan)

3.1.4 Development Plans and Production History

The Uquo full field gas development comprises seven wells including four existing wells, three new wells, and two of these wells to be worked-over. Selective completions allow for separate development and management of the various reservoir intervals. The field has been on production since Q4 2013 and, currently, four gas producers are on stream. The gas is currently exported to Ibom power station, Calabar NIPP power station, and the Unicem cement factory with wells Uquo-2, Uquo-4, Uquo-7 and Uquo-8ST contributing to production as required.

The Uquo-2 well, completed with 4 ½" tubing in the D2.0 sand as a gas producer with sand-control, is capable of gas rates of 35-40 MMscf/d, while the Uquo-4 well, re-completed with 4 ½" tubing in the D1.0 gas sand, is capable of gas rates of 25-30 MMscf/d. Uquo-7 and -8ST wells have been worked-over in H2 2014 and both are completed in the D1.0 gas sand, with 7" tubing capable of gas rates of 60-80 MMscf/d. Gas from the D1.0, D1.3/D1.4, D2.0 is relatively dry (c. 97% methane).

The processing facilities at the site are designed for an export gas rate of 200 MMscf/d. This capacity is provided by two gas-processing trains, and are part of the Central Processing Facility (CPF) which processes gas to meet hydrocarbon and water dew point specifications. In addition, the CPF includes condensate stabilisation, power generation and other utilities. Gas was initially exported through an 18-inch pipeline over 62 km to Ikot Abasi to supply Ibom power station and then via the 128 km 18-inch East Horizon pipeline, also owned by Seven Energy, for alternative gas delivery to the Unicem cement factory and the Calabar NIPP power station. Condensate is transported 8 km through a 4-inch pipeline to the Exxon Mobil Qua Iboe Terminal (**Figure 3.8**). During a second phase of development, a 37 km 24-inch diameter pipeline from Uquo to Oron and a 52 km 24-inch diameter pipeline from Oron to Calabar were completed in 2016, with metering facilities at Calabar. Seven Energy took over the responsibility for construction and ultimately ownership of the 26 km section of pipeline from Oron to Creek Town. The remaining 26 km is under the responsibility of NDPHC (Niger Delta Power Holding Company Ltd). This allows the supply of gas via a more direct route from the Uquo CPF to the Calabar NIPP power station and the Unicem cement plant. It is anticipated that by 2022 (Proved + Probable case) well head pressures will have declined to the point that compression will be required to deliver the required inlet pressure to the export lines.

Current average gas rate delivered for October 2017 was 89 MMscf/d. Cumulative production from Uquo to 31st October 2017 was 82.0 Bscf of gas and 100 Mstb of condensate.

Oil production from the Uquo-3 well started in February 2015 with evacuation via a 4-inch 8 km pipeline to the ExxonMobil Qua Iboe Terminal. The Uquo-9 well (Uquo NE area) has been suspended pending completion within the D1.6 oil-bearing sand in 2018.

3.1.5 Technically Recoverable Volumes, Resources and Predicted Production Profiles

Seven Energy via its 100% owned subsidiary Accugas Limited (Accugas) has existing contracts for gas sales to the Ibom power station, the Calabar NIPP power station and the Unicem cement plant. Refer to **Figure 1.1** for the map of gas customer locations and pipelines.

LR are advised that the first commercial delivery and start date under the Unicem cement plant GSA was from 5th January 2012. Also, that the Ibom power station GSA contract term is 10 years with a start date of 1st January 2014 and the Calabar power station GSA contract term is 20 years with a start date of 22nd September 2017. The initial contract rate (Unicem I) is 22 MMscf/d and by January 2018 (Unicem II) the rate will increase to 38.7 MMscf/d. Ibom Power currently takes 16 MMscf/d, which will increase to the 19.7 MMscf/d contracted rate, while Calabar NIPP demand will increase from 31 MMscf/d to 105 MMscf/d by January 2018 and then to 131 MMscf/d as per the contract.

Savannah has generated appropriate profiles with plateau rates to match the contracted volumes. The model allows for multiple reservoirs and wells to be included, each with its own inflow parameters (GIIP, pressure, temperature, permeability, thickness and skin) and outflow parameters (tubing length, diameter and roughness). Surface compression and pipeline performance are also included. The reservoirs are treated as tanks, in the case of Uquo, with gas flowing in highly permeable reservoirs. This assumption is justified in LR’s view.

The well tests performed in 2010 on Uquo-3 and -2 exhibited low condensate-gas ratio (CGR) yields in the range 0.4 to 4.6 stb/MMscf. Based on average production, LR has adopted a typical yield of 1.256 stb/MMscf in its estimates. The well test performed on Uquo-3 D5.0 sand produced 43° API gravity oil at rates up to 950 bopd.

LR reviewed the input data and assumptions made on the Savannah CMG IMEX simulation model provided for Uquo NE D1.6 reservoir, which provides oil recovery factors in line with regional analogue data of 40%, 50% and 58% for the low, best and high cases. Uquo NE D1.6 oil reservoir forecasts assume development work will start in Q1 2018 with first production in Q3 2018.

Development of the Uquo-3 oil area is complete. Uquo-3 production is declining and no reserves have been attributed to it.

Combined recoverable volumes (prior to application of cessation of production dates) as of 1st November 2017, estimated by LR, are as follows:

Gross Technically Recoverable Volumes	Low	Best	High
Gas (Bscf)	364.5	565.0	788.1
Oil (MMstb) – Uquo NE	3.8	7.2	11.7
Condensate (MMstb)	0.5	0.7	1.0

Table 3.4: Uquo Marginal Field: Gross Oil, Gas and Condensate Technically Recoverable Volumes

Additionally, Contingent Resources in the remaining reservoirs and the NE area are tabulated below. LR has assumed recovery factor ranges of 64 – 90 % for the gas contingent resources and a CGR of 1.256 stb/MMscf.

Gross Contingent Resources	1C	2C	3C
Gas (Bscf)	45.0	72.5	115.6
Oil (MMstb) – Uquo NE	0.9	2.5	5.1
Condensate (MMstb)	0.1	0.1	0.1

Table 3.5: Uquo Marginal Field: Gross Oil, Gas and Condensate Contingent Resources

The Uquo production profiles are based on a maximum contracted gas rate of 189.4 MMscf/d. Potential gas resources in the C6.0 reservoir lying outside the licence area have not been estimated.

LR have been informed that Accugas currently processes raw gas and subsequently sells processed gas to its downstream customers as defined by its existing gas sales agreements. The processed gas is being delivered via Accugas owned pipeline infrastructure. The forecasted gas volumes sold by Accugas are based on cumulative daily contracted quantities (DCQs) under the existing gas sales agreements. This is equivalent to 189.4 MMscf/d. Each GSA has a contractual take or pay provision, where the cumulative take or pay volume under all existing GSAs is equal to 80% of current DCQs or c. 152 MMscf/d. A sales/purchase contract is expected to be signed between the Uquo JV and Accugas. This contract is expected to allow for up to 25 days of downtime annually due to maintenance.

The Uquo field is currently the sole supplier of unprocessed gas to Accugas facilities, while Stubb Creek field is expected to be developed as an additional gas supply to Accugas once Uquo gas production declines below DCQs.

3.1.6 Prospect Summary

Ten exploration prospects have been identified in the Uquo licence (**Figure 3.9**). As a consequence of the licence extension granted by DPR in May 2015, the Uquo-3 E, Uquo-3 W prospects are now entirely within the licence area. In late 2012, Seven Energy / FOL conducted a detailed review of five of these prospects (Uquo NE, -1SE, -3E, -3S and -1N) in order to confirm targets for a drilling campaign. Prospect Uquo NE, with six potential gas reservoirs and the lowest risk, was selected and was drilled as a discovery in 2014 (see Sections 3.1.1 to 3.1.5 above). Only one of the other four prospects (Uquo-3S) was later re-evaluated fully, and only the main reservoirs were re-evaluated for the remaining three prospects and included here. LR have been informed that no new geological nor geophysical data are available on these prospects and LR have adopted previous interpreted volumes, unless otherwise indicated, as a consequence of work carried out by Savannah. HCIIP volumes lying solely within the Uquo Marginal Field licence are included in this report. The Uquo-3S prospect lies south of Uquo-3, and it extends out of the Uquo licence to the south. **Figure 3.1** shows this extension area to be much smaller now that the licence has been extended beyond the original licence boundary (**Figure 3.9**). The main target is the B sandstone sequence, and independent four-way dip closure, supported by strong amplitude anomalies, which is mapped at four different levels, (**Figure 3.10**).

The GIIP estimates for the prospects were evaluated by LR and are shown in **Table 3.6** below.

Gross GIIP (Bscf)	Low	Best	High	Chance of Success[12]
Uquo 1SE	55.7	84.8	139.9	0.50
Uquo 2	13.6	25.4	51.0	0.73
Uquo 2W	71.3	88.4	103.7	0.57
Uquo 3E Licence	151.5	221.7	335.7	0.35
Uquo 3S Licence	114.8	154.3	200.1	0.66
Uquo 3W Licence	72.5	115.2	204.1	0.18
Uquo 3 Extension	10.2	15.1	22.6	0.14
Uquo 3 Attic	13.3	23.4	42.6	0.17
Uquo 3 fault zone	49.0	83.8	93.9	0.20
Uquo 1N	6.1	14.7	35.2	0.18
Total Licence*	**558.0**	**826.8**	**1,228.8**	

*Arithmetic sum

Table 3.6: Uquo Marginal Field: Prospective Resources GIIP

Prospective Resource Potential

The prospects' locations allow them to be tied back to the existing infrastructure and, since they represent several stratigraphic horizons, their chance of success is relatively high as shown in the above table.

A nominal recovery factor of 70% based on detailed work performed on the Uquo Marginal Field by Seven Energy /FOL was used and considered reasonable by LR. The cumulative totals for the unrisked volumes of the ten notional prospects within the licence are illustrated below:

Gross Resources	Low	Best	High
Gas (Bscf)	390.6	578.8	860.2

Table 3.7: Uquo Marginal Field: Gross Prospective Resources

3.2 Stubb Creek Marginal Field

3.2.1 Summary

The Stubb Creek Marginal Field lies within the area OPL 276, formerly OML 14, near the mouth of the Cross River, and was discovered by SPDC in 1971 (**Figure 1.1**). Stubb Creek was classified as a Marginal Field in 2002, and subsequently transferred to the current operator UERL in 2003. Seven Energy acquired a 62.5% interest in UERL in 2010, and thereby gained control over the operatorship of the field by virtue of its shareholding and management position.

Nine wells have been drilled to date on the Stubb Creek Marginal Field.

12 "Chance of Success" for Prospective Resources, means the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface. This, then, is the chance or probability of the Prospective Resource maturing into a Contingent Resource. A High Chance of Success indicates a high chance of discovering hydrocarbons in sufficient quantity for them to be tested to surface.

Four exploration and appraisal wells were drilled by Shell between 1971 and 1983, and five development wells were drilled, tested and completed ready for production by the current operator between 2007 and 2009. Both oil and gas occur in a series of Agbada Formation reservoir sands. Non-associated gas has been proven in four reservoirs, and light oil in three reservoirs.

A 3D seismic survey was acquired by UERL in 2006. SIPEC, acting as technical partner at the time, completed a detailed geoscience evaluation. The database provided previously to LR for the geoscience evaluation was fairly complete, consisting of a Kingdom project containing the 3D dataset and all well data.

In late 2012 Seven Energy conducted a further geophysical and geological review on behalf of the UERL / SIPEC JV, aimed primarily at determining a definitive geological model for the Upper D3 (UD3) sand and providing an update of oil-in-place. This report encompassed a thorough review of seismic interpretation, including well-tie analysis, petrophysical analysis and depth conversion, and incorporated extensive reservoir modelling, which was used as input to a Monte Carlo analysis of STOIIP. Monte Carlo input also included uncertainty factors for several key reservoir parameters. Additionally, a reservoir simulation study was conducted to derive reserves estimates.

In 2014, Seven Energy conducted a detailed subsurface study on the main gas bearing sands on behalf of the UERL / SIPEC JV. This includes the C3, C6, C7, C8 and C9 sands. The objectives of this study were to update the GIIP, generate new profiles, calculate the number of wells required to develop the field and optimise well locations. LR have been informed that the status of data availability and interpretation are unchanged from the previous period of review undertaken in 2016 and have not attempted a reassessment of this data.

In 2017 Savannah, provided information relating to some additional studies that they have carried out as part of their due diligence. LR have incorporated the results of this recent work in their assessment of Reserves.

3.2.2 Subsurface Description

The Stubb Creek Marginal Field consists of oil and gas accumulations in a series of Agbada Formation reservoir sands. Non-associated gas has been proved in four reservoirs (C3, C7, C8 and C9) and light oil in three deeper reservoirs (D3, D5 and D8).

The main oil reservoir is the Upper D3 sand. The Top D3 map shows a rollover anticline with associated complex faulting which trends primarily in an east-west direction (**Figures 3.11 and 3.12**). Correlation of the D3 sandstones is illustrated in **Figure 3.13**. Reservoir properties are good with average porosity of 30% and net to gross of over 90% in the Upper and Lower D3 units.

Examples of the 3D seismic dataset show that it is a significant improvement on the preceding 2D data, with high resolution and clearly visible amplitude anomalies and flat spots through the gas-bearing zones. The more recent Seven Energy Geology and Geophysics studies have adopted a more rigorous approach, and these are regarded as the key reference documents.

Prior to Seven Energy's involvement in Stubb Creek, UERL and SIPEC had viewed the field as primarily an oil development, since neither party had experience of gas development in Nigeria. Therefore, the wells drilled by UERL have been targeted at, and completed in, the oil D-sand reservoirs. The operator carries reserves in all the D3, D5 and D8 sands, but Seven Energy considers only the UD3 sand to be commercial at this point.

Figure 3.11 shows the top UD3 structure depth map presented by Seven Energy, showing both surface and bottom hole well locations. The UD3 has been tested in wells SC-2 and SC-5 and found to have 39 - 40° API gravity oil with a GOR of 632 scf/stb. Permeabilities were assessed to be up to 4 Darcy.

The D3 oil pool lies in a prominent rollover feature with three-way dip closure bounded to the south by an east–west fault. Upper and Lower reservoir sands are present and the main member is the Upper D3 which exhibits clean, high net to gross, good quality characteristics except in wells close to the fault which might have influenced sedimentation patterns. A clear OWC is observed in well SC-2 at 6,188 ft tvdss and at 6,190 ft tvdss in SC-6 for the UD3 reservoir.

Gas has been proven in the C3, C7, C8 and C9 sands, but only the C3, C7 and C9 reservoirs are considered to be extensive and contain commercial volumes.

Although the field now has nine wells, the majority of these have been aimed at evaluating the deeper oil reservoirs in the south of the field, and well control for the C gas-bearing sandstones is limited. For example, the C3, C7 reservoirs were penetrated by SC-1 only, while C8 and C9 by SC-2, SC-7, SC-8 and SC-9 (**Figure 3.14 and 3.15**).

The large areas to the east of the mapped closure for C3, C7 and C9 have not been tested by drilling but the horizon marking the top of the C3 reservoir, which forms a large, crestal rollover with four-way dip closure, is well-defined by its RMS amplitude (**Figure 3.16**). Limits of the closure to the east and west are somewhat difficult to define as they fall beyond the limits of 3D coverage, and extend outside the licence area. The GDT for the UC3 is picked at 3,737 ft tvdss and the GWC for the LC3 is at 3,780 ft tvdss (**Figure 3.14**).

The C7 sand can just be recognised in the northernmost well, SC-1, and it shows two reworked offshore sand bars with prograding and retrograding signatures. These sand bar deposits detected in SC-1 change laterally southward into siltstone and silty shale deposits as may be seen in wells SC-9 and SC-8. These lithological differences point to a different sedimentary environment or different depositional sequence.

Mapping of Top C9 indicates a three-way dip-closed feature against faulting to the south of the field (**Figure 3.17**). The C9 reservoir is a clean sand with high net to gross. The reservoir has been penetrated by four wells, three of which (SC-7, SC-8 and SC-9) indicate clear hydrocarbon contacts (**Figure 3.18**). All three wells demonstrate a gas column of about 100 ft in thickness, above a thin oil rim. Petrophysical analysis by Seven Energy in 2014 confirmed that this rim could be around 12 ft thick, with a maximum OWC of 4,811 ft tvdss. Hydrocarbon contacts were interpreted based on deep resistivity logs and density-neutron separation (where available). Seven Energy assigned 32.6 MMstb P50 STOIIP to this interval but did not consider that production would be possible due to early water and gas coning. LR agrees with this view and has not assigned any oil Reserves to the C9 sand.

3.2.3 Hydrocarbons-Initially-in-Place

The HCIIP estimates provided were calculated probabilistically by Seven Energy and updated by Savannah. LR consider that the volumes below are reasonable based on the current studies but recommend that a full evaluation is carried out based on the mapping and attribute and amplitude reviews particularly of the UC3/LC3 reservoirs and to check that shape and fill factors variations have been correctly applied.

Gross STOIIP (MMstb)	Low	Best	High
UD3	29.9	38.9	49.6
C9*	22.4	32.6	42.5
Total**	**52.3**	**71.5**	**92.1**

*C9 oil volumes not included in reserves. Production from 12 ft oil rim will be difficult due to water and gas coning.

**Arithmetic sum

Table 3.8: Stubb Creek Marginal Field: STOIIP

Gross GIIP (Bscf)	Low	Best	High
UC3	318.5	421.0	481.0
LC3	34.0	45.5	59.3
C6* (Prospect)	13.8	19.8	27.8
C7	16.1	39.4	88.1
C8*	2.6	3.9	5.6
C9	113.8	150.3	191.5
Total**	**482.4**	**656.2**	**819.9**

*C6 and C8 not included in Resources due to small volumes

**Arithmetic sum excluding C6 and C8

Table 3.9: Stubb Creek Marginal Field: GIIP

3.2.4 Development Plans

The Stubb Creek Marginal Field Development Plan for the UD3 oil reservoir assumes that the Stubb Creek Marginal Field will be developed using five production wells and two water injection wells. The remote well sites are connected to an Early Production Facility (EPF), which has facilities to treat and stabilise oil for export by pipeline to the FUN Manifold located north of the Exxon-Mobil Qua Iboe Terminal (QIT) (**Figure 3.8**).

The facilities will be developed in two phases. Phase 1 uses an existing Early Production Facility (EPF) and, during the EPF production phase, the oil rate will be maintained between 2,500 to 3,000 bopd. Phase 2 is to debottleneck the EFP to give a maximum capacity of 5,000 bopd. Seven Energy has completed Phase 1 and is currently forecasting Phase 2 to be complete by September 2018.

Currently, five wells (SC-2, 5, 6, 7 and 8) have been completed as oil producers while well SC-9 has been completed as a water injector. In 2017, Savannah advised LR of the plan to drill a second water injection well in 2018.

Oil production started in February 2015 and crude is being exported to the Qua Iboe Terminal. Three wells are currently on production with an average rate for October 2017 of 2,760 bopd.

3.2.5 Technically Recoverable Volumes and Contingent Resources

Seven Energy, on behalf of the UERL / SIPEC JV, updated the Stubb Creek Reservoir Simulation Study, dated March 2017, following better reservoir pressure response than previously modelled to evaluate well plans, aquifer support, water injection optimisation and recoverable volumes for the oil development case. LR has assumed oil recovery factors of 40, 50 and 58% for the low, best and high cases respectively to estimate oil recovery in **Table 3.10** and develop the range of profiles for economic analysis.

For the gas development, including gas compression, for **Table 3.11** below, LR has assumed a range of gas recovery factors of 69 to 90%, to stochastically derive the estimated recoveries.

Seven Energy has estimated condensate yield for Stubb Creek at 2 stb/MMscf, and this ratio has been accepted by LR and used in the economics.

Cumulative production to 31st October 2017 was 2.0 MMstb of oil.

Technically Recoverable volumes for the oil development are tabulated below:

Gross Technically Recoverable Volumes	Low	Best	High
Oil (MMstb)	10.0	17.5	26.8

Table 3.10: Stubb Creek Marginal Field: Gross Oil Technically Recoverable Volumes

C9 oil volumes are not included in the oil reserves since it is considered that production from the 12 ft oil rim would be difficult due to water and gas coning.

Gas resources contained in the C3, C7 and C9 reservoirs constitute Contingent Resources since they require testing before a detailed Field Development Plan can be submitted for approval.

These Contingent Resources are tabulated below:

Gross Resources	1C	2C	3C
Gas (Bscf)	364.9	515.3	680.3
Condensate (MMstb)	0.7	1.0	1.4

Table 3.11: Stubb Creek Marginal Field: Gross Gas and Condensate Contingent Resources[13]

Note that the production profiles are dovetailed on the decline of Uquo and hence the Stubb Creek Contingent Resources are constrained by Uquo deliverability and contracted gas volumes.

3.3 Facilities and Infrastructure for South East Niger Delta Assets

3.3.1 Integrity Management

The facilities and infrastructure serving the Uquo and Stubb Creek Marginal Fields, as described in previous sections, are at the start of their operating life, and best practice reliability based maintenance is being used for all these facilities. Seven Energy used its alliance with Petrofac, the international oil and gas facilities service provider, to assist with the development of its production, processing and pipeline assets. Petrofac is well respected in the petroleum industry in the areas of facility and integrity management. It has supplied experienced personnel, on secondment to Seven Energy over a three-year period, to assist with the delivery of Seven Energy's key projects, to design and implement best practice operating and maintenance procedures on these key projects. It also assisted in the recruitment and training of management personnel and operating staff. Seven Energy is now fully resourced to deliver production, processing and pipeline projects. The measures taken would support the case that inspection and maintenance of facilities will be carried out to industry standards and on a timely basis and thus should not pose a threat to delivering production.

3.3.2 Abandonment

Abandonment of the the Uquo and Stubb Creek Marginal Fields facilities is scheduled during the next 25 years. There is inevitable uncertainty in future unit rates, the effect of discounting, the condition of wells and details of the abandonment campaign. An AACE Class 5 (screening level) estimate with a nominal accuracy of +/-50% is, therefore, considered appropriate by both operating companies and regulators.

[13] Includes volumes expected to be produced after 2026.

LR has reviewed Savannah and Seven Energy's decommissioning estimation methodology and provision. The estimates are based predominantly on work conducted by 3rd parties which LR considers to be both reputable and competent. Pipeline estimates were developed, or based on, those done by the original installation contractor, Evomec. Estimates for the gas receiving facility, central processing facility and FUN manifold were developed by Petrofac personnel. The wells estimates were generated by Seven Energy.

LR considers the breakdown of work structures associated with each element of the estimates to be reflective of good engineering practice and the associated costs to be both reasonable for the scope described and in line with other abandonment cost estimates it has seen. The level of technical definition presented for facilities and pipeline estimates is greater than that often seen for Class 5 abandonment estimates for which a simple allowance of 10% of Capex, with a nominal accuracy of +/-50%, is often adopted. The estimates presented lie within this range. The well abandonment cost estimates are considered conservative when compared to many seen for similar wells.

Overall, LR considers the estimating approach adopted by Seven Energy to be reasonable and in line with industry accepted practice.

3.4 Accugas Midstream Assets

3.4.1 Accugas Midstream Business

The Accugas midstream business focuses on the processing, distribution and sale of gas to power station and industrial customers in the South East Nigeria market. The business comprises the 200 MMscf/d Uquo gas processing facility, a c.260 km pipeline network as well as long-term gas sales agreements (GSAs) with downstream customers. The Uquo Gas CPF consists of two identical gas processing trains. Each train has been designed to process 100 MMscf/d, however one has been tested up to 120 MMscf/d. It is the opinion of Seven Energy that the plant could operate at 240 MMscf/d on a continuous basis.

Accugas buys raw gas from its sole current supplier, the Uquo field joint venture (the Uquo JV) at a price of US$1.7/Mscf, and sells this gas to three separate customers at a weighted average price (based on DCQ volumes) of US$3.5/Mscf. This price is expected to increase by an weighted average (based on DCQ volumes) of up to 6.4% p.a. over the next six years and up to 1.5% thereafter due to inflation clauses which are included in the GSAs, the key terms of which are summarised in **Table 3.12** below:

	Calabar NIPP	Unicem	Ibom Power
Description	**Nigerian State Power Plant**	**Lafarge Cement Plant**	**Nigerian State Power Plant**
Term (Remaining)	20 Years (20)	20 years (14)	10 years (6)
Start Date	September 2017	January 2012	January 2014
Daily Contract Quantity (DCQ)	131 MMscf/d	38.7 MMscf/d	19.7 MMscf/d
Take-or-Pay	80%	80%	80%
Gas Price	US$3.29/Mscf for the first year (price escalation applies)	US$5.00/Mscf	US$2.15/Mscf (price escalation applies)

Table 3.12: Accugas Summary of Key Gas Sales Agreements[14]

[14] DCQ and Gas price defined in calorific value in some GSAs, have been converted to volume in this table.

Accugas' gas consumed in operations and processing cost impact is estimated by Savannah at US$0.14/Mscf in real terms. Accugas also pays an education tax of 2% and Nigerian corporate income tax of 30%. Capital allowances can be used to reduce taxable profits with no restrictions.

Savannah has entered into a conditional investment agreement pursuant to which a private equity investor, African Infrastructure Investment Fund 3 ("AIIM"), together with potentially one or more co-investors, will acquire an 80 percent interest in Accugas. Savannah intends to acquire a 20 percent minority interest in the business, providing the Company with visibility of the key end customers for its gas. LR have viewed the Term Sheet which preceded the conditional investment agreement, but not the conditional investment agreement.

Current Business Plan

The historic focus of the Accugas business has primarily been on the high volume, lower price power station customers which sell their gas into the Nigerian market.

Going forward, Accugas intends to focus on opportunities to increase gas supplies to new "low volume, high value" industrial customers whose typical alternative source of power is diesel, with the Accugas facilities tying into three principal industrial activity hubs, the Calabar area, the Port Harcourt area and the city of Aba.

Under the proposed terms of the relevant contracts, the Uquo JV will have priority for the provision of gas to the existing Uquo CPF and a right to price match any future volumes on any additional CPFs. The pricing formula currently set out in the draft heads of agreement under negotiation between the parties is such that any increase in realised prices above US$3.40/Mscf is shared on a 50:50 basis between the upstream Uquo JV and Accugas.

LR are informed that Seven Energy has signed a Heads of Terms with certain potential new industrial customers in the Calabar area, in the vicinity of Accugas pipelines for gas sales of up to 5 MMscf/d at an average price of US$7.5/Mscf. LR are informed that Seven Energy has also mapped seven additional end consumers in the Calabar area who they believe would be most willing to switch to gas, aggregating demand of nearly 20 MMscf/d, and is of the view that similar potential also exists in the Port Harcourt area. These agreements have not been reviewed by LR.

4. Economic Evaluation

4.1 Upstream Economics

LR's evaluation used the economic model provided by Savannah for the Licence' assets. The model was audited by LR and found to be in accordance with the current, relevant fiscal and commercial terms (**Table 4.1**).

Inputs to the economic model consist of production profiles for each of the assets, which have been generated by LR, and the capital and operating costs which have been determined from the operator's 5-year plan and determined for the life of field by LR based on the production forecasts and the requirement for well and infrastructure spend. These production and expenditure profiles are shown in Appendices A and B. All costs are forward looking estimates over field life and presented in nominal terms unless stated otherwise.

4.1.1 Economic Inputs

Fiscal Modelling Assumptions

In the South East Niger Delta, Seven Energy holds: (i) a 40% participating interest in the Uquo Marginal Field via its 100% owned subsidiary Seven Uquo Gas Limited (SUGL) and (ii) a 31.9% participating interest in the Stubb Creek Marginal Field via its 62.5% owned subsidiary Universal Energy Resources Limited (UERL), which in turn holds a 51% interest in the Stubb Creek Marginal Field. Frontier Oil Limited (FOL) is the operator of the Uquo Marginal Field and UERL is the operator of Stubb Creek Marginal Field.

The Uquo JV (FOL (60%) and SUGL (40%)) assumes that pioneer relief will be granted and that SUGL will be given the benefits of a 5-year tax holiday. Thereafter, Petroleum Profits Tax (PPT) for oil is assumed at 85% and for gas Corporate Income Tax (CIT) is charged at 30%.

The Stubb Creek JV (UERL (51%) and SIPEC (49%)) assumes that pioneer relief will not be granted and that UERL will be taxed at the PPT rate for oil (65.75% for the first five years of production ending in 2019) and the CIT rate for gas (30%).

Refer to **Tables 4.2 to 4.5** for the cost assumptions.

	Uquo		Stubb Creek	
Governing law	Marginal Field		Marginal Field	
Participating License Interest	40.0%		31.9%	
Paying Interest	Pre NPV equalisation: 100%. Post NPV equalisation[15]: Gas 48.0% & Oil 52.0%		Oil 20% & Gas 50%	
Revenue (Uquo)/Profit (Stubb Creek) Interest	Pre NPV equalisation: Gas 87.7% & Oil 85.0% Post NPV equalisation: Gas 48.0% & Oil 52.0%		Oil 35% & Gas 60%	
Royalty - Oil	Above bopd 0 2,001 5,001 10,001 15,001	Royalty Rate 2.5% 2.5% 7.5% 12.5% 18.5%	Above bopd 0 2,001 5,001 10,001 15,001	Royalty Rate 2.5% 2.5% 7.5% 12.5% 18.5%
Royalty - Gas	7.0%		7.0%	
Overriding Royalty - Oil	Above bopd 0 2,001 5,001 10,001 15,001	Royalty Rate 2.5% 3.0% 5.5% 7.5% tbd	Above bopd 0 2,001 5,001 10,001 15,001	Royalty Rate 2.5% 3.0% 5.5% 7.5% tbd
Education Tax	2.0%		2.0%	
NDDC Levy	3.0%		3.0%	
PPT	Tax holiday to 2019 & 85.0% thereafter		65.75% to 2020 and 85.0% thereafter	
CIT	30.0%		30.0%	
Capital Allowances	100% on exploration, development and first two appraisal wells. 20.0% for four years plus 19.0% for fifth year on other capex. Capital allowances used in any given year are restricted to 85.0% of assessable profit.		100% on exploration, development and first two appraisal wells. 20.0% for four years plus 19.0% for fifth year on other capex. Capital allowances used in any given year are restricted to 85.0% of assessable profit.	
PIA	5.0%		5.0%	

Table 4.1: Fiscal Terms: Uquo and Stubb Creek Marginal Fields

[15] NPV equalisation: once both JV partners have achieved a 15% Internal Rate of Return.

Gross Costs- Uquo and Stubb Creek Marginal Fields - 2P

	Uquo	Stubb Creek
Gross Capex (US$MM)	176.7	25.8
Fixed Opex (US$MM)	80.6	175.4

Table 4.2: Gross Costs Proved+Probable Case Uquo and Stubb Creek Marginal Fields[16]

Capital expenditure (Capex) and operating costs (Opex) were escalated at 2% for oil and 4.7% for gas from 2017 onwards. The detailed Capex costs are shown in Appendix B.

Capex and Opex per Barrel of oil equivalent (boe). (1 boe = 6,000 scf).

Capex US$ per boe		
Asset	Capex per boe - Field	Capex per boe - Seven
Uquo (2P)	1.73	1.98
Stubb Creek (2P+2C)	2.56	2.35

Table 4.3: Capex per boe

Opex US$ per boe		
Asset	Opex per boe- Field	Opex per boe - Seven
Uquo (2P)	1.29	1.47
Stubb Creek (2P+2C)	2.67	1.33

Table 4.4: Opex per boe

Nominal (net) abandonment costs for the 6 cases for Uquo and Stubb Creek Marginal Fields are in **Table 4.5**.

Case	Uquo	Stubb Creek[17]
1P	35.7	4.5
1P & 1C	40.3	8.3
2P	38.4	4.7
2P&2C	44.7	8.5
3P	19.0	4.7
3P&3C	22.1	8.5

Table 4.5: Abandonment Costs (Nominal), Uquo and Stubb Creek Marginal Fields (US$MM)

[16] Total costs from 1st November 2017 to economic limit.

[17] For 62.5% of UERL's abandonment obligations.

Pricing

Gas prices for 2017 were provided by Savannah and are expected to be equal to US$1.70 per Mscf as per the gas sales agreement expected to be signed with Accugas. Thereafter, the gas price is expected to increase based on the downstream gas price inflation. This is forecast to increase by a weighted average (based on DCQ volumes) of 6.4% p.a. for the next six years and 1.5% thereafter.

Crude oil price was assumed to be US$60/bbl real for January 2018. Prices were escalated at 2% per annum from 2018 onwards.

4.1.2 Economic Valuation of Developed Fields

The 1st November 2017 has been used as the discount date for valuations in nominal terms based on cashflows that have been escalated for price and costs. Past costs from 2006 to date are included for cost recovery.

Production profiles were produced by LR for each field as reported in Section 3. These profiles were curtailed at the limit of economic production to generate the Reserves volumes reported in the Executive Summary.

Estimates of the NPV, based on discounted cashflow of future net revenues, after deduction of taxes and royalties, at a discount rate of 10%, derived from the Seven Energy share as of 1st November 2017, are summarised in **Table 4.6** for reserves.

NPV10[18] (US$MM) for Reserves Net to Seven Energy			
	Proved	Proved + Probable	Proved + Probable + Possible
South East Niger Delta:			
Uquo liquids	61.1	103.1	141.3
Uquo gas	261.0	397.3	494.6
Stubb Creek oil	26.1	47.6	55.3
Total NPV10* (US$MM)	**348.2**	**548.0**	**691.2**

*Note that the totals may not sum exactly due to rounding.

Table 4.6: NPV10 for Reserves Net to Seven Energy Post Taxes and Royalties

[18] NPV: Net Present Value after deduction of Taxes and Royalties at a 10% discount rate.

Totals do not take account of dependencies and have been arithmetically summed. This method of summation is recommended under PRMS guidelines and results in conservative low case and optimistic high case totals. Totals may not add exactly due to rounding.

2P Portfolio Sensitivity

The 2P portfolio NPV10 was run with a range of oil prices. The corresponding values are shown in **Table 4.7** below:

Portfolio	US$/bbl										
	$30	$35	$40	$45	$50	$55	$60	$65	$70	$75	$80
Uquo	434.5	447.3	459.2	470.2	480.6	491.1	500.4	509.8	519.1	528.4	537.6
Stubb Creek	11.4	18.0	24.6	31.6	39.1	44.3	47.6	50.3	53.0	55.5	58.0
NPV10 ($MM)	**445.9**	**465.3**	**483.8**	**501.7**	**519.7**	**535.4**	**548.0**	**560.2**	**572.1**	**583.9**	**595.6**
Portfolio (%)	**-18.6%**	**-15.1%**	**-11.7%**	**-8.4%**	**-5.2%**	**-2.3%**	**0.0%**	**2.2%**	**4.4%**	**6.6%**	**8.7%**

Table 4.7: Proved+Probable NPV Sensitivity to Oil Price

Upstream Netbacks

A Netback is a summary of all the costs associated with bringing one barrel of oil or oil equivalent to the marketplace. This is calculated by taking all of the revenues from the oil, less all associated costs excluding abandonment and general and administration costs.

The following netbacks are in nominal terms over the life of the field based on an oil price of US$60/bbl real for 2018 (**Table 4.8**).

	Uquo - Oil (2P)	Uquo - Gas (2P)	Stubb Creek - Oil (2P)	Stubb Creek - Gas (2C)
	Netback - Seven Energy (US$/bbl)	Netback - Seven Energy (US$/boe)	Netback - Seven Energy (US$/bbl)	Netback - Seven Energy (US$/boe)
Revenue	68.1	13.1	68.0	16.8
Royalties	3.4	0.9	3.5	1.2
NDDC Levy	0.7	0.1	0.3	0.1
Education tax	0.7	0.2	0.8	0.3
PPT	10.8	-	12.7	-
CIT	-	2.4	-	4.5
Opex	13.8	0.5	10.3	0.5
Capex	8.4	1.5	1.3	2.5
Netback (pre Abex and G&A)	**30.3**	**7.5**	**39.1**	**7.7**

Table 4.8: Uquo Proved+Probable and Stubb Creek Proved+Probable and 2C Oil and Gas Upstream Netback

4.2 Midstream Economics

4.2.1 Accugas Midstream Economic Assumptions

LR's evaluation of the intended ultimate structure under which Savannah would retain a 20% interest in Accugas used the economic model provided by Savannah for the business. LR have conducted a high level review of the economic model and found it to be in accordance with the assumed fiscal, commercial and contractual terms. Assuming contracted sales volumes, the key terms of which are summarized in Section 3.4.1, LR has reviewed a base case NPV10 for 100% of the Accugas business of US$1,045MM (as of 1st November 2017) (**Table 4.9**).

	100%	Savannah's 20% share
Accugas NPV (in US$MM)	1,045	209

Table 4.9: NPV10 for Accugas Midstream Business

Key upstream commercial terms are summarized in Section 4.1.1. Gas can be supplied to Accugas from both the Uquo and Stubb Creek Marginal fields, as well as other potential sources of supply, noting that, subject to agreement, it is expected that the Uquo JV will have exclusivity for the provision of gas to the existing Uquo CPF and that Savannah is expected to have a contractual right of first refusal to supply gas to Accugas. LR have not investigated the potential impact of penalties, if either incurred and applicable, related to any under-delivery of sales gas.

4.2.2 Netback Sensitivity to Potential Additional Accugas Gas Sales

The Uquo JV currently acts as sole supplier to the Accugas midstream business, which as discussed in Section 3.4.1 is expected to be acquired by Savannah Petroleum and a group of one or more private equity investors.

Under the terms of this transaction, Savannah is expected to have a contractual right of first refusal to supply gas to Accugas. Under its new owners, Accugas is anticipated to follow a strategy focused around the addition of new industrial customers. Also under the proposed terms of the relevant contracts, the Uquo JV will have exclusivity for the provision of gas to the existing Uquo CPF and a right to price match any future volumes on any additional CPFs. The pricing formula currently set out in the draft heads of agreement under negotiation between the parties is such that any increase in realised prices above US$3.40/Mscf is shared on a 50:50 basis between the upstream Uquo JV and Accugas.

It is the opinion of Seven Energy that the Uquo Gas CPF could operate at 240 MMscf/d on a continuous basis as one of two trains has been tested up to 120 MMscf/d, higher than its nameplate capacity of 100 MMscf/d. With a 240 MMscf/d effective capacity, Uquo Gas CPF has enough capacity to process additional 50 MMscf/d on top of 189.4 MMscf/d that has been contracted by the existing three Accugas customers. Accugas total pipeline transport capacity is currently 300 MMscf/d from the Uquo CPF towards the East (Calabar area) and 230 MMscf/d towards the West (Port Harcourt).

Savannah have provided the following sensitivity analysis of the change in upstream and midstream netbacks to demonstrate the potential impact of potential additional production being contracted at higher prices over time (**Tables 4.10 and 4.11**).

Estimated netbacks are theoretical netbacks associated with each boe of gas delivered to new customers at various downstream prices. Downstream and upstream gas price, as well as all costs are in real (1st November 2017) terms. Upstream price is based on the pricing formula per the terms of the expected Accugas GSA and is effectively equal to 50% of the downstream price. Royalties and taxes are calculated based on the existing fiscal terms (see **Table 4.1**) in the absence of any tax losses or capital allowances being brought forward.

Indicative Upstream Netback Price Sensitivity (US$ per boe)				
Downstream price assumption (US$ per Mscf)	3.4	5.0	7.5	11.0
Upstream price assumption (US$ per Mscf)	1.70	2.50	3.75	5.50
Revenue	10.2	15.0	22.5	33.0
Royalty	0.7	1.1	1.6	2.3
NDDC Levy	0.05	0.05	0.05	0.05
Education tax	0.2	0.3	0.4	0.6
CIT	2.5	3.8	5.9	8.8
Opex	0.3	0.3	0.3	0.3
Capex	1.2	1.2	1.2	1.2
Netback[19]	**5.2**	**8.3**	**13.0**	**19.7**

Table 4.10: Indicative Gross Upstream Netback Price Sensitivity (US$ per boe)

Indicative Midstream Netback Price Sensitivity (US$ per boe)				
Downstream price (US$ per Mscf)	3.4	5.0	7.5	11.0
Upstream price (US$ per Mscf)	1.7	2.5	3.75	5.5
Revenue	20.4	30.0	45.0	66.0
Feedstock price	10.2	15.0	22.5	33.0
NDDC Levy	0.04	0.04	0.04	0.04
Education tax	0.2	0.3	0.4	0.6
CIT	2.3	3.8	6.0	9.0
Fixed Opex	0.8	0.8	0.8	0.8
Capex	0.6	0.6	0.6	0.6
Netback[19]	**6.3**	**9.6**	**14.7**	**21.9**

Table 4.11: Indicative Gross Midstream Netback Price Sensitivity (US$ per boe)

[19] Excludes abandonment cost and G&A.

5. References

1. "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information", published by the Society of Petroleum Engineers (SPE) in June 2001, SPE website (www.spe.org).
2. "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information Approved by SPE Boards June 2001 - Revision as of February 19, 2007", published by the Society of Petroleum Engineers (SPE); SPE website (www.spe.org).
3. "Petroleum Resources Management System", Sponsored by SPE, AAPG, WPC, SPEE, published 2007; SPE website (www.spe.org).
4. "Petroleum Reserves Definitions" approved by SPE and WPC March 1997; SPE website (www.spe.org).
5. "Note for Mining and Oil & Gas Companies – June 2009", London Stock Exchange.

Appendix A

Production Profiles

LR has constructed gross and net production profiles for the 1P Proved, 2P Proved plus Probable and 3P Proved plus Probable plus Possible Reserves, and 1C, 2C and 3C Contingent Resources. Tables A.1 to A.6 and Figures A.1 to A.3 show consolidated and field profiles for the portfolios of assets in the license areas.

Gross Consolidated Production Profile South East Niger Delta Assets, Uquo and Stubb Creek Marginal Fields

	South East Niger Delta			South East Niger Delta			South East Niger Delta			South East Niger Delta		
	Oil + Condensate (bopd)			Gas (MMscf/d)			Oil + Condensate (bopd)			Gas (MMscf/d)		
Year	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2017	2946	3026	3119	80.6	82.1	94.4	0	0	0	0.0	0.0	0.0
2018	3764	4212	4554	154.9	163.6	189.6	0	0	0	0.0	0.0	0.0
2019	6211	6654	6652	154.9	189.6	189.6	0	0	0	0.0	0.0	0.0
2020	6270	6670	6999	169.9	189.6	213.1	0	0	0	0.0	0.0	0.0
2021	5556	6670	7418	169.9	189.6	213.1	0	0	0	0.0	0.0	0.0
2022	4480	6670	7418	158.8	189.6	213.1	15	0	0	11.1	0.0	0.0
2023	3446	6630	7418	89.1	189.6	213.1	285	0	0	80.8	0.0	0.0
2024	2484	5940	7376	44.7	155.8	180.1	587	18	0	105.5	14.2	0.0
2025	1791	5140	7390	22.3	100.7	190.9	616	92	0	127.7	68.9	0.0
2026	1295	4479	7368	11.1	62.8	173.4	644	188	22	138.8	106.8	17.5
2027	938	3620	7010	5.6	39.2	118.6	639	563	299	144.4	130.4	72.3
2028	680	2656	6074	2.8	24.6	79.8	549	828	765	147.2	145.2	111.5
2029	491	2156	5223	0.0	15.3	53.4	477	852	1151	150.0	154.4	137.5
2030	357	1724	4499	0.0	9.6	35.8	354	867	1471	115.4	160.1	155.1
2031	259	1373	3880	0.0	6.0	24.1	197	876	1729	55.7	163.7	166.9
2032	189	1099	3351	0.0	3.7	16.2	113	805	1836	26.7	127.3	124.9
2033	137	877	2897	0.0	2.3	10.8	67	807	2005	12.8	128.7	130.1
2034	100	708	2507	0.0	0.0	7.3	41	807	1970	6.1	131.0	123.7
2035	72	564	2171	0.0	0.0	4.9	20	720	1572	0.0	107.6	126.1
2036	46	436	1882	0.0	0.0	3.3	9	600	1252	0.0	68.9	127.7
2037	26	280	1629	0.0	0.0	0.0	0	511	1015	0.0	44.1	131.0
2038	19	229	1415	0.0	0.0	0.0	0	444	830	0.0	28.3	131.0
2039	14	186	1229	0.0	0.0	0.0	0	391	690	0.0	18.1	131.0
2040	10	152	1069	0.0	0.0	0.0	0	348	585	0.0	11.6	131.0

Production Profiles are Technical Recoverable Volumes and are not subject to economic cut-off. Numbers subject to rounding.

Table A.1

Net Consolidated Production Profile South East Niger Delta Assets, Uquo and Stubb Creek Marginal Fields

Net	South East Niger Delta			South East Niger Delta			South East Niger Delta			South East Niger Delta		
	Oil + Condensate (bopd)			Gas (MMscf/d)			Oil + Condensate (bopd)			Gas (MMscf/d)		
Year	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2017	601	613	636	70.8	72.0	82.9	0	0	0	0.0	0.0	0.0
2018	951	1107	1173	135.9	143.6	166.4	0	0	0	0.0	0.0	0.0
2019	1908	2285	2283	135.9	166.4	166.4	0	0	0	0.0	0.0	0.0
2020	1958	2298	2578	149.1	166.4	187.0	0	0	0	0.0	0.0	0.0
2021	1869	2298	2934	149.1	166.4	187.0	0	0	0	0.0	0.0	0.0
2022	1723	2356	3024	139.3	166.4	187.0	13	0	0	9.8	0.0	0.0
2023	1406	2568	3200	78.2	166.4	187.0	210	0	0	58.6	0.0	0.0
2024	1056	2374	3145	39.1	136.4	157.6	418	15	0	54.0	12.4	0.0
2025	779	2179	3162	19.5	88.3	167.5	360	95	0	51.1	56.0	0.0
2026	532	2009	2919	9.8	55.2	137.0	381	145	242	50.9	66.7	30.5
2027	369	1601	2088	4.9	34.4	57.0	370	395	706	51.6	62.4	77.4
2028	263	1046	1762	2.4	21.5	38.2	280	575	429	52.7	59.8	46.5
2029	186	837	1480	0.0	13.4	25.7	210	568	612	54.7	58.9	55.2
2030	134	648	1245	0.0	8.4	17.2	146	562	759	42.5	59.0	58.9
2031	97	496	1048	0.0	5.2	11.6	87	557	872	20.5	60.1	61.5
2032	70	383	884	0.0	3.3	7.8	57	531	941	9.6	46.1	45.6
2033	50	294	745	0.0	2.0	5.2	38	528	1009	4.4	46.9	47.3
2034	36	232	629	0.0	0.0	3.5	26	522	986	1.9	48.2	44.4
2035	26	176	531	0.0	0.0	2.3	17	476	765	0.0	39.9	45.8
2036	13	122	448	0.0	0.0	1.6	7	424	594	0.0	25.4	46.6
2037	3	35	377	0.0	0.0	0.0	0	376	465	0.0	16.1	47.6
2038	2	29	319	0.0	0.0	0.0	0	336	367	0.0	10.1	48.1
2039	2	23	270	0.0	0.0	0.0	0	306	288	0.0	6.3	48.6
2040	1	15	199	0.0	0.0	0.0	0	279	222	0.0	3.8	48.6

Production Profiles are Technical Recoverable Volumes and are not subject to economic cut-off. Numbers subject to rounding.

Table A.2

Gross Production Profile Uquo Marginal Field

	Uquo			Uquo			Uquo			Uquo		
	Oil + Condensate (bopd)			Gas (MMscf/d)			Oil + Condensate (bopd)			Gas (MMscf/d)		
Year	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2017	321	323	339	80.6	82.1	94.4	0	0	0	0.0	0.0	0.0
2018	662	801	833	154.9	163.6	189.6	0	0	0	0.0	0.0	0.0
2019	1561	2004	2002	154.9	189.6	189.6	0	0	0	0.0	0.0	0.0
2020	1620	2020	2349	169.9	189.6	213.1	0	0	0	0.0	0.0	0.0
2021	1620	2020	2768	169.9	189.6	213.1	0	0	0	0.0	0.0	0.0
2022	1604	2020	2768	158.8	189.6	213.1	15	0	0	11.1	0.0	0.0
2023	1345	2020	2768	89.1	189.6	213.1	241	0	0	58.7	0.0	0.0
2024	948	1976	2726	44.7	155.8	180.1	444	18	0	34.0	14.2	0.0
2025	669	1908	2740	22.3	100.7	190.9	386	77	0	12.8	61.0	0.0
2026	475	1842	2718	11.1	62.8	173.4	376	90	22	4.8	57.8	17.5
2027	339	1470	2446	5.6	39.2	118.6	354	367	285	1.8	32.2	65.2
2028	242	902	2005	2.8	24.6	79.8	255	571	683	0.0	17.0	70.1
2029	171	725	1647	0.0	15.3	53.4	177	561	995	0.0	9.0	59.6
2030	123	557	1355	0.0	9.6	35.8	123	556	1238	0.0	4.7	38.6
2031	89	421	1117	0.0	6.0	24.1	86	553	1445	0.0	2.5	25.0
2032	64	323	922	0.0	3.7	16.2	60	550	1619	0.0	0.0	16.2
2033	46	244	761	0.0	2.3	10.8	42	550	1766	0.0	0.0	10.4
2034	33	192	629	0.0	0.0	7.3	29	545	1736	0.0	0.0	6.7
2035	24	142	520	0.0	0.0	4.9	20	505	1329	0.0	0.0	4.3
2036	11	92	431	0.0	0.0	3.3	9	462	1002	0.0	0.0	2.8
2037	0	0	354	0.0	0.0	0.0	0	423	753	0.0	0.0	0.0
2038	0	0	293	0.0	0.0	0.0	0	387	568	0.0	0.0	0.0
2039	0	0	243	0.0	0.0	0.0	0	354	428	0.0	0.0	0.0
2040	0	0	202	0.0	0.0	0.0	0	324	323	0.0	0.0	0.0

Production Profiles are Technical Recoverable Volumes and are not subject to economic cut-off. Numbers subject to rounding.

Table A.3

Net Production Profile Uquo Marginal Field

Net	Uquo			Uquo			Uquo			Uquo		
	Oil + Condensate (bopd)			Gas (MMscf/d)			Oil + Condensate (bopd)			Gas (MMscf/d)		
Year	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2017	273	275	288	70.8	72.0	82.9	0	0	0	0.0	0.0	0.0
2018	563	680	708	135.9	143.6	166.4	0	0	0	0.0	0.0	0.0
2019	1326	1703	1702	135.9	166.4	166.4	0	0	0	0.0	0.0	0.0
2020	1377	1717	1997	149.1	166.4	187.0	0	0	0	0.0	0.0	0.0
2021	1377	1717	2353	149.1	166.4	187.0	0	0	0	0.0	0.0	0.0
2022	1363	1717	2353	139.3	166.4	187.0	13	0	0	9.8	0.0	0.0
2023	1143	1717	2353	78.2	166.4	187.0	205	0	0	51.5	0.0	0.0
2024	806	1680	2317	39.1	136.4	157.6	378	15	0	29.7	12.4	0.0
2025	569	1622	2329	19.5	88.3	167.5	328	65	0	11.2	53.6	0.0
2026	404	1566	2086	9.8	55.2	137.0	320	77	242	4.2	50.7	30.5
2027	288	1249	1272	4.9	34.4	57.0	301	312	673	1.6	28.2	75.2
2028	206	767	1043	2.4	21.5	38.2	217	486	355	0.0	14.9	33.6
2029	146	616	856	0.0	13.4	25.7	151	477	517	0.0	7.9	28.6
2030	105	474	705	0.0	8.4	17.2	105	473	644	0.0	4.2	18.6
2031	75	358	581	0.0	5.2	11.6	73	470	751	0.0	2.2	12.0
2032	54	274	479	0.0	3.3	7.8	51	468	842	0.0	0.0	7.7
2033	39	207	396	0.0	2.0	5.2	35	468	918	0.0	0.0	5.0
2034	28	163	327	0.0	0.0	3.5	25	463	903	0.0	0.0	3.2
2035	20	121	270	0.0	0.0	2.3	17	429	691	0.0	0.0	2.1
2036	9	78	224	0.0	0.0	1.6	7	393	521	0.0	0.0	1.3
2037	0	0	184	0.0	0.0	0.0	0	360	391	0.0	0.0	0.0
2038	0	0	152	0.0	0.0	0.0	0	329	295	0.0	0.0	0.0
2039	0	0	126	0.0	0.0	0.0	0	301	223	0.0	0.0	0.0
2040	0	0	105	0.0	0.0	0.0	0	276	168	0.0	0.0	0.0

Production Profiles are Technical Recoverable Volumes and are not subject to economic cut-off. Numbers subject to rounding.

Table A.4

Gross Production Profile Stubb Creek Marginal Field

	Stubb Creek Oil (bopd)			Stubb Creek Solution Gas (MMscf/d)			Stubb Creek Condensate (bopd)			Stubb Creek Gas (MMscf/d)		
Year	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2017	2625	2702	2780	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2018	3102	3412	3721	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2019	4650	4650	4650	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2020	4650	4650	4650	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2021	3936	4650	4650	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2022	2876	4650	4650	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2023	2101	4611	4650	0.0	0.0	0.0	44	0	0	22.2	0.0	0.0
2024	1536	3963	4650	0.0	0.0	0.0	143	0	0	71.5	0.0	0.0
2025	1122	3232	4650	0.0	0.0	0.0	230	16	0	114.9	7.9	0.0
2026	820	2636	4650	0.0	0.0	0.0	268	98	0	134.0	48.9	0.0
2027	599	2150	4564	0.0	0.0	0.0	285	196	14	142.6	98.2	7.1
2028	438	1754	4068	0.0	0.0	0.0	294	256	83	147.2	128.2	41.3
2029	320	1431	3576	0.0	0.0	0.0	300	291	156	150.0	145.4	77.9
2030	234	1167	3144	0.0	0.0	0.0	231	311	233	115.4	155.4	116.5
2031	171	952	2764	0.0	0.0	0.0	111	322	284	55.7	161.2	142.0
2032	125	777	2430	0.0	0.0	0.0	53	255	217	26.7	127.3	108.7
2033	91	633	2136	0.0	0.0	0.0	26	257	239	12.8	128.7	119.7
2034	67	517	1878	0.0	0.0	0.0	12	262	234	6.1	131.0	117.0
2035	49	421	1651	0.0	0.0	0.0	0	215	244	0.0	107.6	121.8
2036	36	344	1451	0.0	0.0	0.0	0	138	250	0.0	68.9	124.9
2037	26	280	1276	0.0	0.0	0.0	0	88	262	0.0	44.1	131.0
2038	19	229	1121	0.0	0.0	0.0	0	57	262	0.0	28.3	131.0
2039	14	186	986	0.0	0.0	0.0	0	36	262	0.0	18.1	131.0
2040	10	152	867	0.0	0.0	0.0	0	23	262	0.0	11.6	131.0

Production Profiles are Technical Recoverable Volumes and are not subject to economic cut-off. Numbers subject to rounding.
In the 3C case, the profiles have been cut for reporting in this table but production post-2040 is included in the Resources reported in Table ES3.

Table A.5

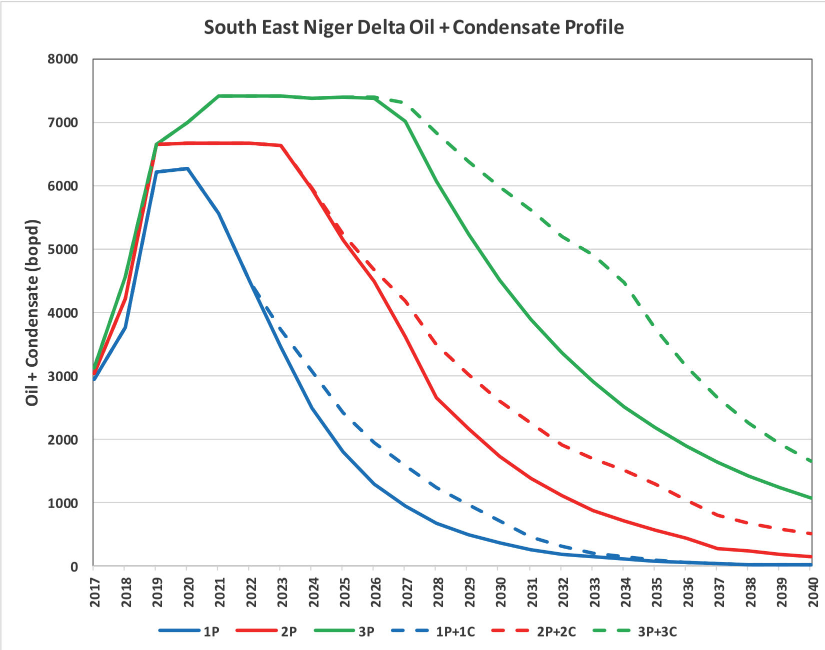
Net Production Profile Stubb Creek Marginal Field

Net	Stubb Creek			Stubb Creek			Stubb Creek			Stubb Creek		
	Oil (bopd)			Solution Gas (MMscf/d)			Condensate (bopd)			Gas (MMscf/d)		
Year	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2017	328	338	348	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2018	388	426	465	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2019	581	581	581	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2020	581	581	581	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2021	492	581	581	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2022	360	639	671	0.0	0.0	0.0	0	0	0	0.0	0.0	0.0
2023	263	852	847	0.0	0.0	0.0	6	0	0	7.1	0.0	0.0
2024	250	694	828	0.0	0.0	0.0	40	0	0	24.3	0.0	0.0
2025	210	557	833	0.0	0.0	0.0	31	30	0	39.9	2.5	0.0
2026	128	443	833	0.0	0.0	0.0	62	68	0	46.7	16.0	0.0
2027	81	352	816	0.0	0.0	0.0	69	83	32	50.0	34.2	2.2
2028	57	279	719	0.0	0.0	0.0	64	90	74	52.7	44.9	12.9
2029	40	221	623	0.0	0.0	0.0	59	91	95	54.7	51.0	26.6
2030	29	175	540	0.0	0.0	0.0	41	90	115	42.5	54.8	40.3
2031	21	138	467	0.0	0.0	0.0	14	87	121	20.5	57.9	49.5
2032	16	109	404	0.0	0.0	0.0	7	63	99	9.6	46.1	37.8
2033	11	87	349	0.0	0.0	0.0	3	61	91	4.4	46.9	42.3
2034	8	69	302	0.0	0.0	0.0	2	59	83	1.9	48.2	41.2
2035	6	55	260	0.0	0.0	0.0	0	47	74	0.0	39.9	43.7
2036	4	43	225	0.0	0.0	0.0	0	31	74	0.0	25.4	45.3
2037	3	35	194	0.0	0.0	0.0	0	16	74	0.0	16.1	47.6
2038	2	29	167	0.0	0.0	0.0	0	7	72	0.0	10.1	48.1
2039	2	23	144	0.0	0.0	0.0	0	5	66	0.0	6.3	48.6
2040	1	15	95	0.0	0.0	0.0	0	3	54	0.0	3.8	48.6

Production Profiles are Technical Recoverable Volumes and are not subject to economic cut-off. Numbers subject to rounding.
In the 3C case, the profiles have been cut for reporting in this table but production post-2040 is included in the Resources reported in Table ES3.

Table A.6

Consolidated Production Profile South East Niger Delta Assets, Uquo and Stubb Creek Marginal Fields



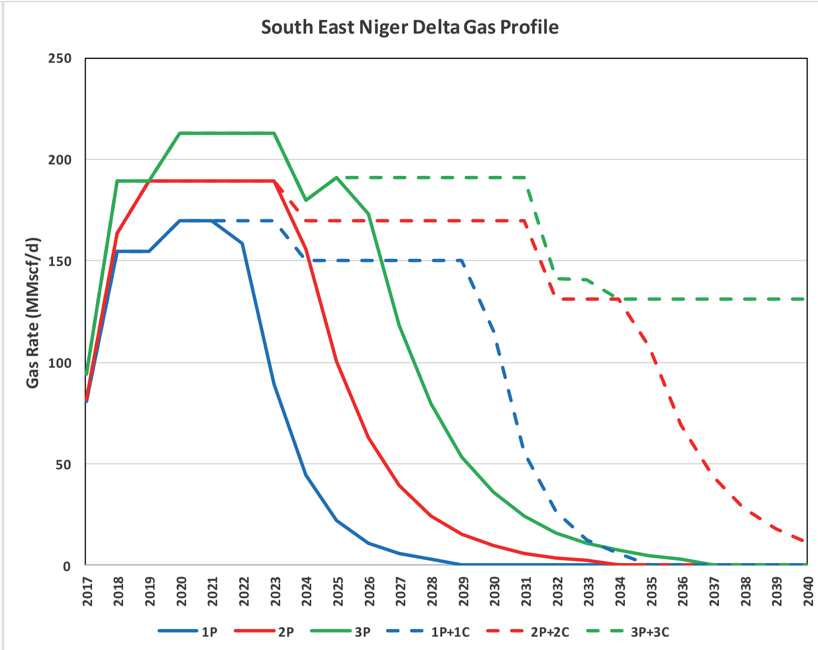
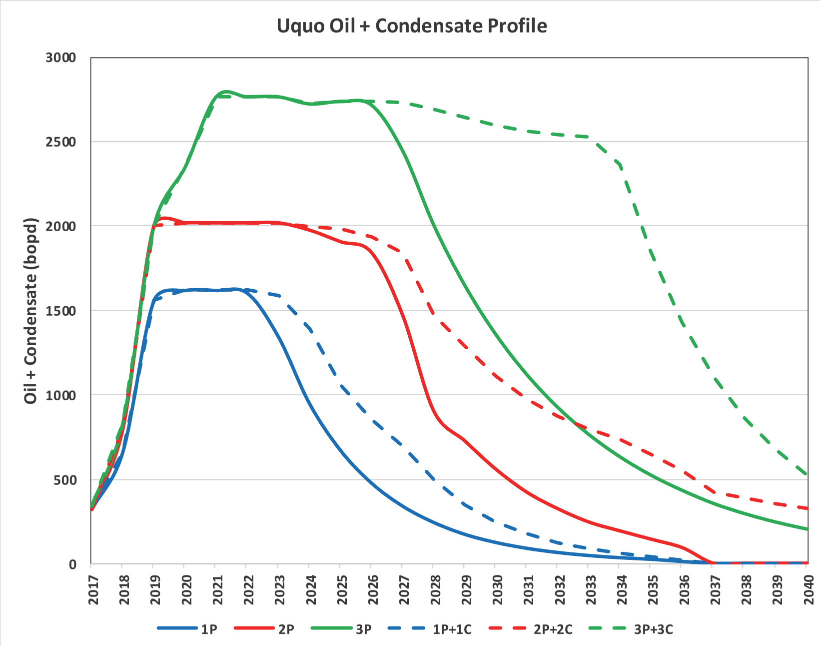


Figure A.1

File No. \Savannah\K17SAV002L\Report

Prepared for: Savannah

Production Profile Uquo Marginal Field



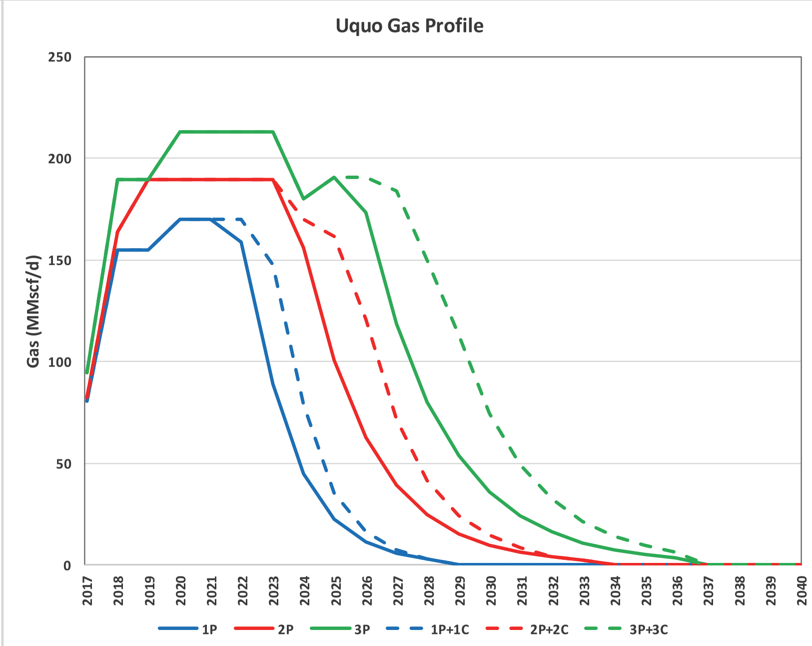


Figure A.2

File No. \Savannah\K17SAV002L\Report

Prepared for: Savannah

Production Profile Stubb Creek Marginal Field

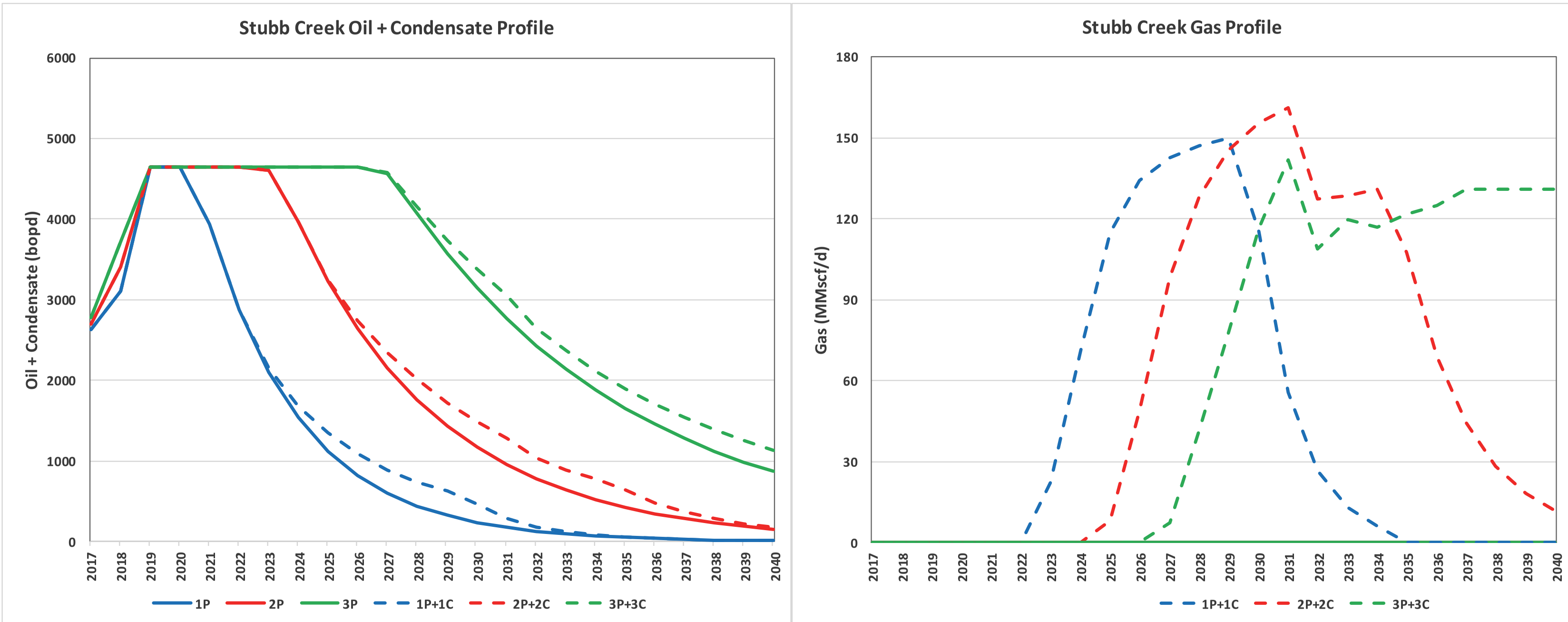


Figure A.3

Appendix B

Capital and Operating Costs

Detailed Gross and Net Capex and Opex cost forecasts are shown in the following Tables B.1 to B.8.

Forecast Free Cashflow Net to Seven Energy is presented in Table B.9.

Gross Capital Expenditure - Uquo Upstream

Uquo						
Gross Capital Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	0.0	0.0	0.0	0.0	0.0	0.0
2018	33.5	0.0	33.5	0.0	33.5	0.0
2019	41.4	0.0	41.4	0.0	21.2	0.0
2020	21.0	0.0	21.2	0.0	24.0	0.0
2021	39.9	0.0	22.1	0.0	22.1	0.0
2022	18.5	55.2	30.3	0.0	0.0	0.0
2023	0.0	11.9	7.5	0.0	31.3	0.0
2024	0.0	0.0	20.7	51.1	54.2	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	21.8	0.0	69.9
2027	0.0	0.0	0.0	0.0	0.0	7.3
2028	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
Total	**154.3**	**67.1**	**176.7**	**72.8**	**186.3**	**77.3**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.1

Net Capital Expenditure - Uquo Upstream

Uquo						
Net Capital Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	0.0	0.0	0.0	0.0	0.0	0.0
2018	33.5	0.0	33.5	0.0	33.5	0.0
2019	41.4	0.0	41.4	0.0	21.2	0.0
2020	21.0	0.0	21.2	0.0	24.0	0.0
2021	39.9	0.0	22.1	0.0	22.1	0.0
2022	18.5	55.2	30.3	0.0	0.0	0.0
2023	0.0	11.9	7.5	0.0	31.3	0.0
2024	0.0	0.0	20.7	51.1	54.2	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	21.8	0.0	69.9
2027	0.0	0.0	0.0	0.0	0.0	7.3
2028	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
Total	**154.3**	**67.1**	**176.7**	**72.8**	**186.3**	**77.3**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.2

Gross Operating Expenditure - Uquo Upstream

Uquo						
Gross Fixed Operating Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	4.0	0.0	4.0	0.0	4.0	0.0
2018	4.2	0.0	4.2	0.0	4.2	0.0
2019	4.3	0.0	4.3	0.0	4.3	0.0
2020	4.4	0.0	4.4	0.0	4.4	0.0
2021	4.6	0.0	4.6	0.0	4.6	0.0
2022	4.7	0.0	4.7	0.0	4.7	0.0
2023	4.9	0.0	4.9	0.0	4.9	0.0
2024	5.0	0.0	5.0	0.0	5.0	0.0
2025	4.9	0.0	4.9	0.0	4.9	0.0
2026	4.5	0.0	4.5	0.0	4.5	0.0
2027	4.6	0.0	4.6	0.0	4.6	0.0
2028	4.8	0.0	4.8	0.0	4.8	0.0
2029	2.3	0.0	5.0	0.0	5.0	0.0
2030	2.4	0.0	5.1	0.0	5.1	0.0
2031	2.4	0.0	5.3	0.0	5.3	0.0
2032	2.4	0.0	5.5	0.0	5.5	0.0
2033	2.5	0.0	5.7	0.0	5.7	0.0
2034	2.5	0.0	2.5	0.0	5.9	0.0
2035	2.6	0.0	2.6	0.0	6.1	0.0
2036	1.5	0.0	2.7	0.0	6.3	0.0
2037	0.0	0.0	0.0	2.7	2.7	0.0
2038	0.0	0.0	0.0	2.8	2.8	0.0
2039	0.0	0.0	0.0	2.8	2.8	0.0
2040	0.0	0.0	0.0	2.9	2.9	0.0
Total	**73.7**	**0.0**	**89.4**	**11.1**	**111.0**	**0.0**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.3

Net Operating Expenditure - Uquo Upstream

Uquo						
Net Fixed Operating Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	4.0	0.0	4.0	0.0	4.0	0.0
2018	4.2	0.0	4.2	0.0	4.2	0.0
2019	4.3	0.0	4.3	0.0	4.3	0.0
2020	4.4	0.0	4.4	0.0	4.4	0.0
2021	4.6	0.0	4.6	0.0	4.6	0.0
2022	4.7	0.0	4.7	0.0	4.7	0.0
2023	4.9	0.0	4.9	0.0	4.9	0.0
2024	5.0	0.0	5.0	0.0	5.0	0.0
2025	4.9	0.0	4.9	0.0	4.9	0.0
2026	4.5	0.0	4.5	0.0	4.0	0.6
2027	4.6	0.0	4.6	0.0	2.3	1.3
2028	4.8	0.0	4.8	0.0	2.4	0.0
2029	2.3	0.0	5.0	0.0	2.5	0.0
2030	2.4	0.0	5.1	0.0	2.6	0.0
2031	2.4	0.0	5.3	0.0	2.6	0.0
2032	2.4	0.0	5.5	0.0	2.7	0.0
2033	2.5	0.0	5.7	0.0	2.8	0.0
2034	2.5	0.0	2.5	0.0	2.9	0.0
2035	2.6	0.0	2.6	0.0	3.0	0.0
2036	1.5	0.0	2.7	0.0	3.1	0.0
2037	0.0	0.0	0.0	2.7	1.4	0.0
2038	0.0	0.0	0.0	2.8	1.4	0.0
2039	0.0	0.0	0.0	2.8	1.5	0.0
2040	0.0	0.0	0.0	2.9	1.5	0.0
Total	**73.7**	**0.0**	**89.4**	**11.1**	**77.8**	**1.9**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.4

Gross Capital Expenditure - Stubb Creek

Stubb Creek						
Gross Capital Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	0.0	0.0	0.0	0.0	0.0	0.0
2018	25.8	0.0	25.8	0.0	25.8	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	68.6	0.0	0.0	0.0	0.0
2024	0.0	61.9	0.0	0.0	0.0	0.0
2025	0.0	43.3	0.0	26.5	0.0	0.0
2026	0.0	28.2	0.0	53.5	0.0	0.0
2027	0.0	0.0	0.0	56.0	0.0	29.0
2028	0.0	0.0	0.0	30.1	0.0	58.6
2029	0.0	0.0	0.0	31.5	0.0	20.2
2030	0.0	0.0	0.0	33.0	0.0	43.3
2031	0.0	0.0	0.0	0.0	0.0	34.6
2032	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	37.9
2034	0.0	0.0	0.0	0.0	0.0	39.6
2035	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
Total	**25.8**	**202.1**	**25.8**	**230.8**	**25.8**	**263.3**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.5

Net Capital Expenditure - Stubb Creek

Stubb Creek						
Net Capital Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	0.0	0.0	0.0	0.0	0.0	0.0
2018	3.2	0.0	3.2	0.0	3.2	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	21.4	0.0	0.0	0.0	0.0
2024	0.0	19.3	0.0	0.0	0.0	0.0
2025	0.0	13.5	0.0	8.3	0.0	0.0
2026	0.0	8.8	0.0	16.7	0.0	0.0
2027	0.0	0.0	0.0	17.5	0.0	9.1
2028	0.0	0.0	0.0	9.4	0.0	18.3
2029	0.0	0.0	0.0	9.9	0.0	6.3
2030	0.0	0.0	0.0	10.3	0.0	13.5
2031	0.0	0.0	0.0	0.0	0.0	10.8
2032	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	11.8
2034	0.0	0.0	0.0	0.0	0.0	12.4
2035	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	0.0	0.0	0.0	0.0
2039	0.0	0.0	0.0	0.0	0.0	0.0
2040	0.0	0.0	0.0	0.0	0.0	0.0
Total	**3.2**	**63.2**	**3.2**	**72.1**	**3.2**	**82.3**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.6

Gross Fixed Operating Expenditure - Stubb Creek

Stubb Creek						
Gross Fixed Operating Expenditure ($MM)						
	1P	1C	2P	2C	3P	3C
2017	10.3	0.0	10.3	0.0	10.3	0.0
2018	12.9	0.0	12.9	0.0	12.9	0.0
2019	13.1	0.0	13.1	0.0	13.1	0.0
2020	13.4	0.0	13.4	0.0	13.4	0.0
2021	12.3	0.0	12.3	0.0	12.3	0.0
2022	10.4	0.0	10.4	0.0	10.4	0.0
2023	8.8	2.0	8.8	0.0	8.8	0.0
2024	7.4	2.8	7.4	0.0	7.4	0.0
2025	7.1	3.0	7.1	1.5	7.1	0.0
2026	7.2	3.1	7.2	3.1	7.2	0.0
2027	7.4	3.2	7.4	3.2	7.4	1.6
2028	7.5	3.4	7.5	3.4	7.5	3.4
2029	7.7	3.5	7.7	3.5	7.7	3.5
2030	7.8	3.7	7.8	3.7	7.8	3.7
2031	8.0	3.9	8.0	3.9	8.0	3.9
2032	8.2	4.1	8.2	4.1	8.2	4.1
2033	8.3	4.3	8.3	4.3	8.3	4.3
2034	8.5	4.5	8.5	4.5	8.5	4.5
2035	8.7	0.0	8.7	4.7	8.7	4.7
2036	8.8	0.0	8.8	4.9	8.8	4.9
2037	9.0	0.0	9.0	5.1	9.0	5.1
2038	9.2	0.0	9.2	5.3	9.2	5.3
2039	9.4	0.0	9.4	5.6	9.4	5.6
2040	7.2	0.0	7.2	8.3	7.2	8.3
Total	**218.7**	**41.4**	**218.7**	**69.0**	**218.7**	**62.8**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.7

Net Fixed Operating Expenditure - Stubb Creek

Stubb Creek						
Net Fixed Operating Expenditure (US$MM)						
	1P	1C	2P	2C	3P	3C
2017	1.3	0.0	1.3	0.0	1.3	0.0
2018	1.6	0.0	1.6	0.0	1.6	0.0
2019	1.6	0.0	1.6	0.0	1.6	0.0
2020	1.7	0.0	1.7	0.0	1.7	0.0
2021	1.5	0.0	1.5	0.0	1.5	0.0
2022	1.3	0.0	1.3	0.0	1.3	0.0
2023	1.1	0.6	1.1	0.0	1.1	0.0
2024	0.9	0.9	0.9	0.0	0.9	0.0
2025	0.9	0.9	0.9	0.5	0.9	0.0
2026	0.9	1.0	0.9	1.0	0.9	0.0
2027	0.9	1.0	0.9	1.0	0.9	0.5
2028	0.9	1.1	0.9	1.1	0.9	1.1
2029	1.0	1.1	1.0	1.1	1.0	1.1
2030	1.0	1.2	1.0	1.2	1.0	1.2
2031	1.0	1.2	1.0	1.2	1.0	1.2
2032	1.0	1.3	1.0	1.3	1.0	1.3
2033	1.0	1.3	1.0	1.3	1.0	1.3
2034	1.1	1.4	1.1	1.4	1.1	1.4
2035	1.1	0.0	1.1	1.5	1.1	1.5
2036	1.1	0.0	1.1	1.5	1.1	1.5
2037	1.1	0.0	1.1	1.6	1.1	1.6
2038	1.1	0.0	1.1	1.7	1.1	1.7
2039	1.2	0.0	1.2	1.7	1.2	1.7
2040	0.9	0.0	0.9	2.1	0.9	2.1
Total	**27.3**	**12.9**	**27.3**	**21.1**	**27.3**	**19.2**

Numbers subject to rounding. Costs are not subject to economic cut-off

Table B.8

Free Cashflow Net to Seven Energy

Free Cashflow (net to Seven Energy)		2018	2019	2020	2021	2022	Total
Uquo	(US$MM)	56.5	70.3	89.5	94.3	92.9	403.3
Stubb Creek	(US$MM)	2.5	8.3	8.2	8.4	9.9	37.2
Total	**(US$MM)**	**58.9**	**78.5**	**97.7**	**102.7**	**102.7**	**440.5**

Numbers subject to rounding

Table B.9

Nomenclature

Variable	Meaning	Units
1P	Proved Reserves	
2P	Proved plus Probable Reserves	
3P	Proved plus Probable plus Possible Reserves	
2D	Two dimensional	
3D	Three dimensional	
Abex	Abandonment expenditure	
Admission	Process of admission of an entity to a Stock Market.	
AIM	Alternative Investment Market of the London Stock Exchange	
API	American Petroleum Institute	
AVO	Amplitude versus offset or amplitude variation with offset is often used as a direct hydrocarbon indicator.	
bbl/d	Barrels per day	
Bc	Barrels condensate	
Best Estimate	An estimate representing the best technical assessment of projected volumes. Often associated with a central, P50 or Mean value.	
BHFP	Bottom hole flowing pressure	psi
BHP	Bottom Hole and Reservoir Pressures	
BHSIP	Bottom hole shut in pressure	psi
BTC	Best technical case	
Bo	Formation volume factor	
boe	Barrels of oil equivalent (1 boe = 6,000 scf)	
bopd	Barrels of oil per day	
bpd condensate	Barrels per day of condensate	
BPU	Base Permian Unconformity	
Bscf	Billions of standard cubic feet	
btu	British Thermal Unit	
bwpd	Barrels of water per day	
Capex	Capital expenditure	
CGR	Condensate/Gas Ratio	
CIT	Corporate Income tax	
CO2	Carbon dioxide	
COD	Chance of development	
Contingent Resources	Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.	

COS	Chance of geological success for an exploration prospect. The probability is typically expressed as a percentage.	
Cp	Centipoises	
CPF	Central Processing Facility	
d	Day	
DCA	Decline Curve Analysis	
DCQ	Daily contracted quantity	
DHI	Direct hydrocarbon indicators	
DoC	Declaration of Commerciality	
DPIIP	Discovered petroleum initially in place	
DPR	Department of Petroleum Resources	
DST	Drill stem test	
EMV	Expected Monetary Value	
EOR	Enhanced Oil Recovery	
EPF	Early production facility	
º F / º C	Degrees Fahrenheit / Centigrade	
EUR	Estimated ultimate recovery	
FDP	Field Development Programme	
FEED	Front-end engineering design	
FOL	Frontier Oil Limited	
FWHP	Flowing wellhead pressure	Psi
FWL	Free water level	
g/cc	Grams / cubic centimeter	
GCR	Gas condensate ratio	
GDT	Gas down to	
GIIP	Gas Initially In Place	
GOC	Gas Oil Contact	
GOR	Gas Oil Ratio	
GRV	Gross Rock Volume	
GSA	Gas Sales Agreement	
GWC	Gas-water contact	
H	Thickness	ft or m
HCPV	Hydrocarbon pore volume	
HCIIP	Hydrocarbons Initially in Place	
k	Permeability	mD
ka	Air permeability	mD
kamb	Ambient condition permeability	mD
Kb	Rock bulk modulus	psi

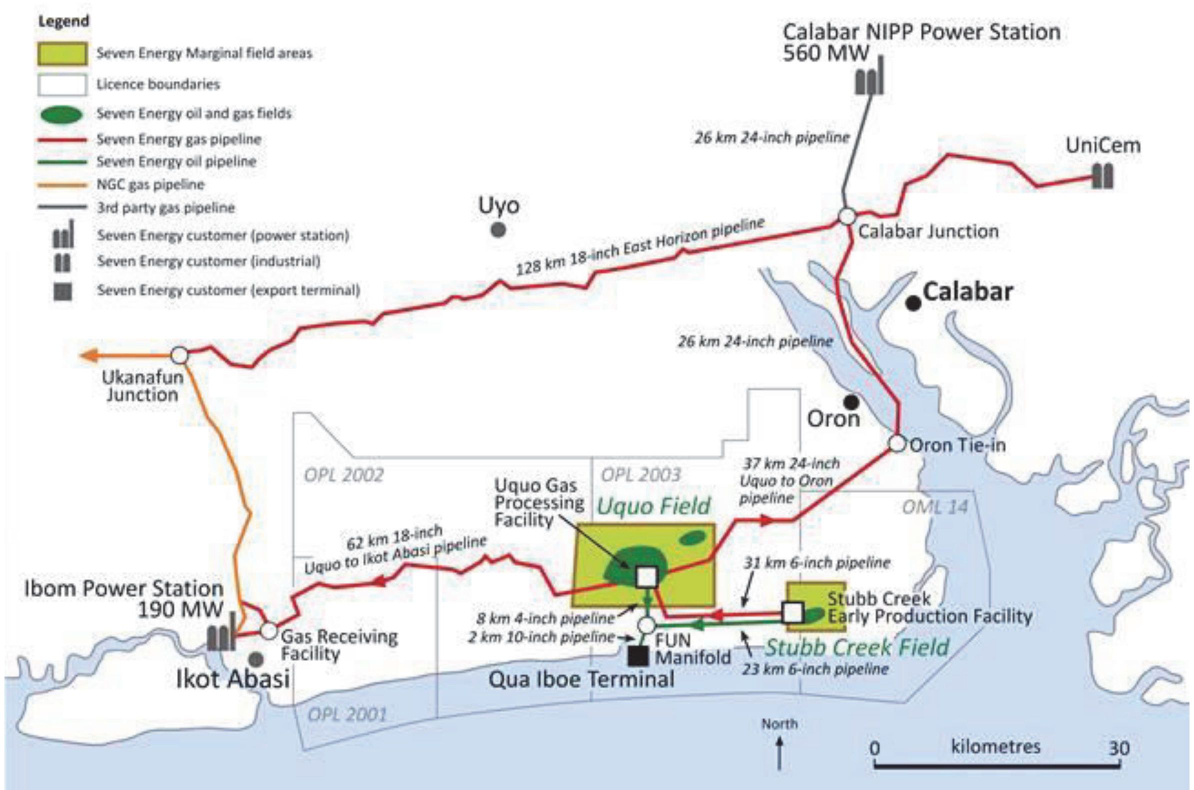
kg	Effective gas permeability	mD
kh	Permeability-thickness	mDft
Kppm	Thousand parts per million	
kw	Water Permeability	mD
LCC	Lowest closing contour	
Mbal	Material Balance. A means of assessing HIIP	
Mscf	Million cubic feet	
MD	Measured depth	ft or m
mD	Millidarcies	
MDRKB	Measured Depth Rotary Kelly Bushing	ft or m
MDBRT	Measured depth Below Rotary Table	ft or m
Mean	The arithmetic average of a set of values	
Mg/l	Milligrams per litre	
MJ/Sm3	Mega Joules per standard metre cubed.	
MM	Million	
MMbbl	Million barrel/s	
MMbo	Million barrels oil	
MMboe	Millions of barrels of oil equivalent	
MMBTU	Million British Thermal Units	
MMscfd	Million cubic feet per day	
MMcm/d	Million cubic meters per day	
MMscf/d	Million standard cubic feet per day	
MMstb	Millions of barrels of stock tank oil	
MMU	Mid-Miocene Unconformity	
mRT	Meters below rotary table	
NPV	Net present value	
NTG	Net to gross	
ODT	Oil down to	
OIIP	Oil Initially In Place	
Opex	Operating expenditure	
OUT	Oil up to	
OWC	Oil water contact	
P99	The probability of that a stated volume will be equalled or exceeded. In this example a 99% chance that the actual volume will be greater than or equal to that stated.	
PIA	Petroleum Investment Allowances	
Pres	Reservoir pressure	Psi
P&A	Plug and abandon	
PDO	Plan of Development and Operation	

phi-k	Porosity-Permeability	
ppg	pounds per gallon	
ppm	Parts per million	
PPT	Petroleum profits tax	
Producing	Related to development projects (e.g. wells and platforms): Active facilities, currently involved in the extraction (production) of hydrocarbons from discovered reservoirs.	
Prospective Resources	Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development.	
Proved	Proved Reserves are those quantities of petroleum, which, by analysis of geosciences 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.	
Proved plus Probable	Probable Reserves are those additional Reserves which analysis of geosciences 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.	
Proved plus Probable plus Possible	Possible Reserves are those additional reserves which analysis of geosciences and engineering data suggest 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) Reserves, which is equivalent to the high estimate scenario. In this context, 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.	
PSDM	Pre-Stack Depth Migration	
psi	Pounds per square inch	
PSTM	Pre Stack Time Migration	
PVT	Pressure Volume Temperature: Measurement of the variation in petroleum properties as the stated parameters are varied.	
P/Z	Reservoir pressure (P) divided by the compressibility factor (Z), which plotted against cumulative gas volume produced provides a simplified material balance analysis for gas fields.	
QIT	Exxon-Mobil Qua Iboe Terminal	

Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.	
RF	Recovery factor	
scf	Standard cubic foot	
SIPEC	Sinopec International Petroleum Exploration and Production Company Nigeria Limited	
stb/d	Stock tank barrels per day	
STOIIP	Stock tank oil initially in place	
SUGL	Seven Uquo Gas Limited	
Sw	Water saturation	ratio
Tscf	Trillion cubic feet	
TCM	Technical Committee Meeting	
TD	Total depth	ft or m
THP	Tubing head pressure	
TRV	Technical Recoverable Volumes	
TVD	True vertical depth	
TVDBRT	True vertical depth below rotary table	ft or m
TWT	Two-way time	
tvdss	True vertical depth sub-sea	ft or m
UERL	Universal Energy Resources Limited	
USD	US dollars	
USGS	United States Geological Survey	
VoK	Average velocity function for depth conversion of time based seismic data, where Vo is the initial velocity and k provides information on the increase or decrease in velocity with depth. V0+k therefore provides a method of depth conversion using a linear velocity field, increasing or decreasing with depth for each geological zone.	
Vsh	Shale volume	
WGR	Water gas ratio	
WHP	Wellhead pressure	Psi
WPC	World Petroleum Council	
WUT	Water up to	

Figures

Seven Energy Assets – Infrastructure

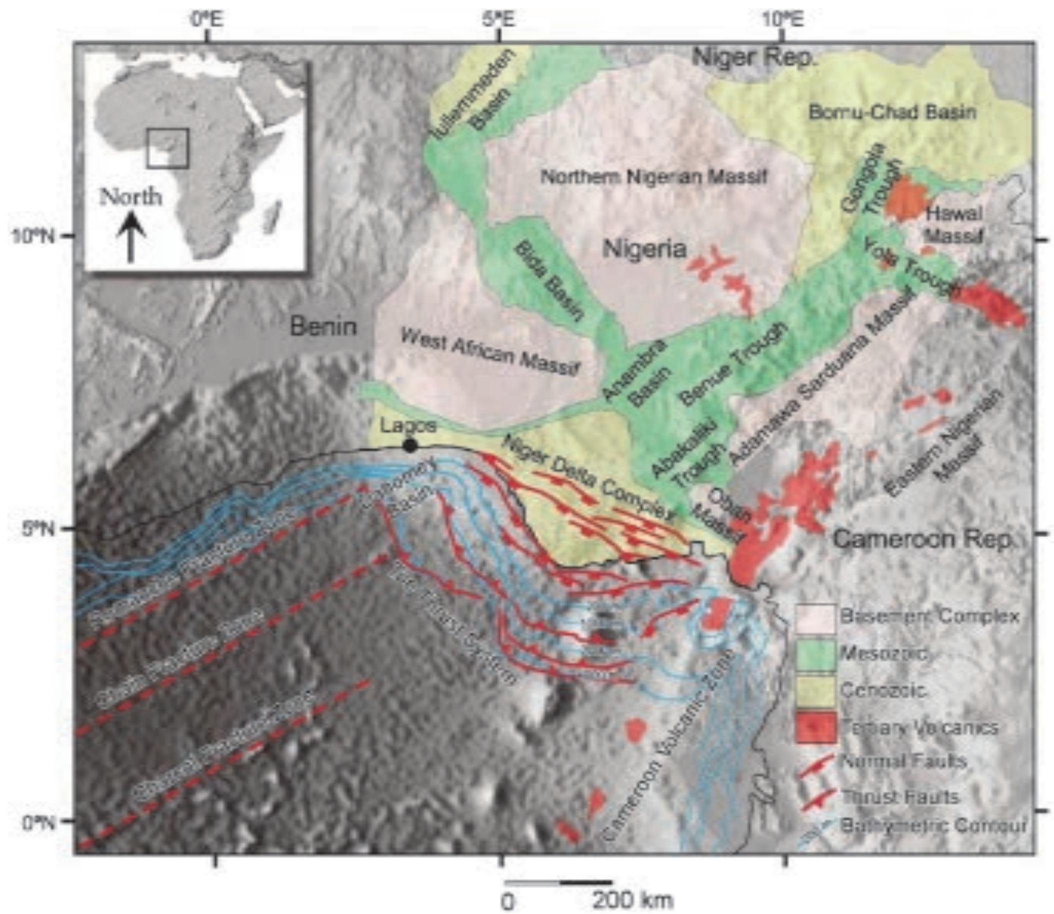


Source: Seven Energy 2017

Note: OPLs 2001, 2002 and 2003 formerly known as OML 13

Figure 1.1

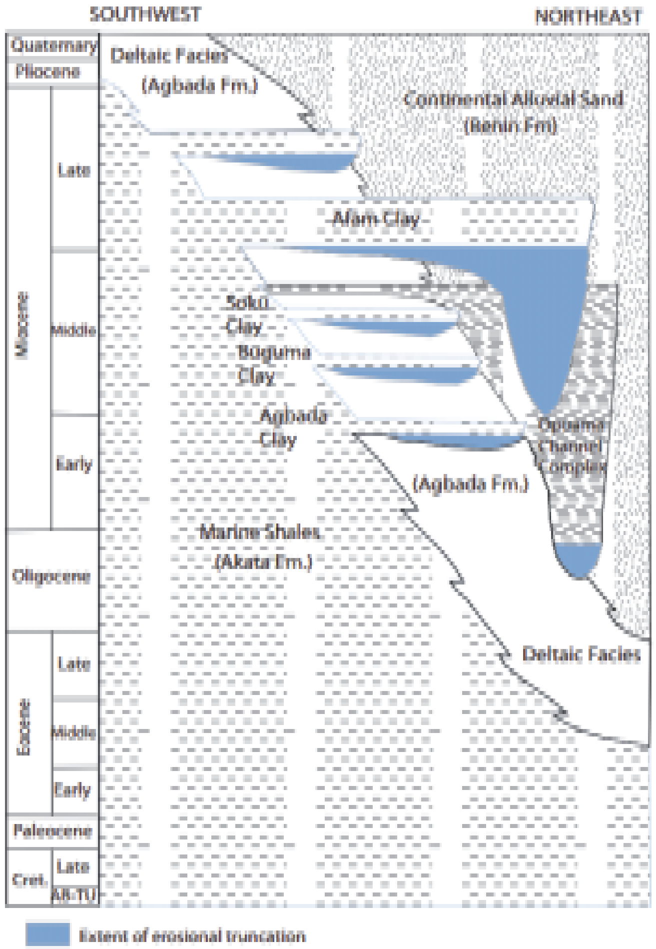
Regional Setting – Niger Delta Map



Source: Copyright 2005, Corredor et al, the American Association of Petroleum Geologists

Figure 2.1

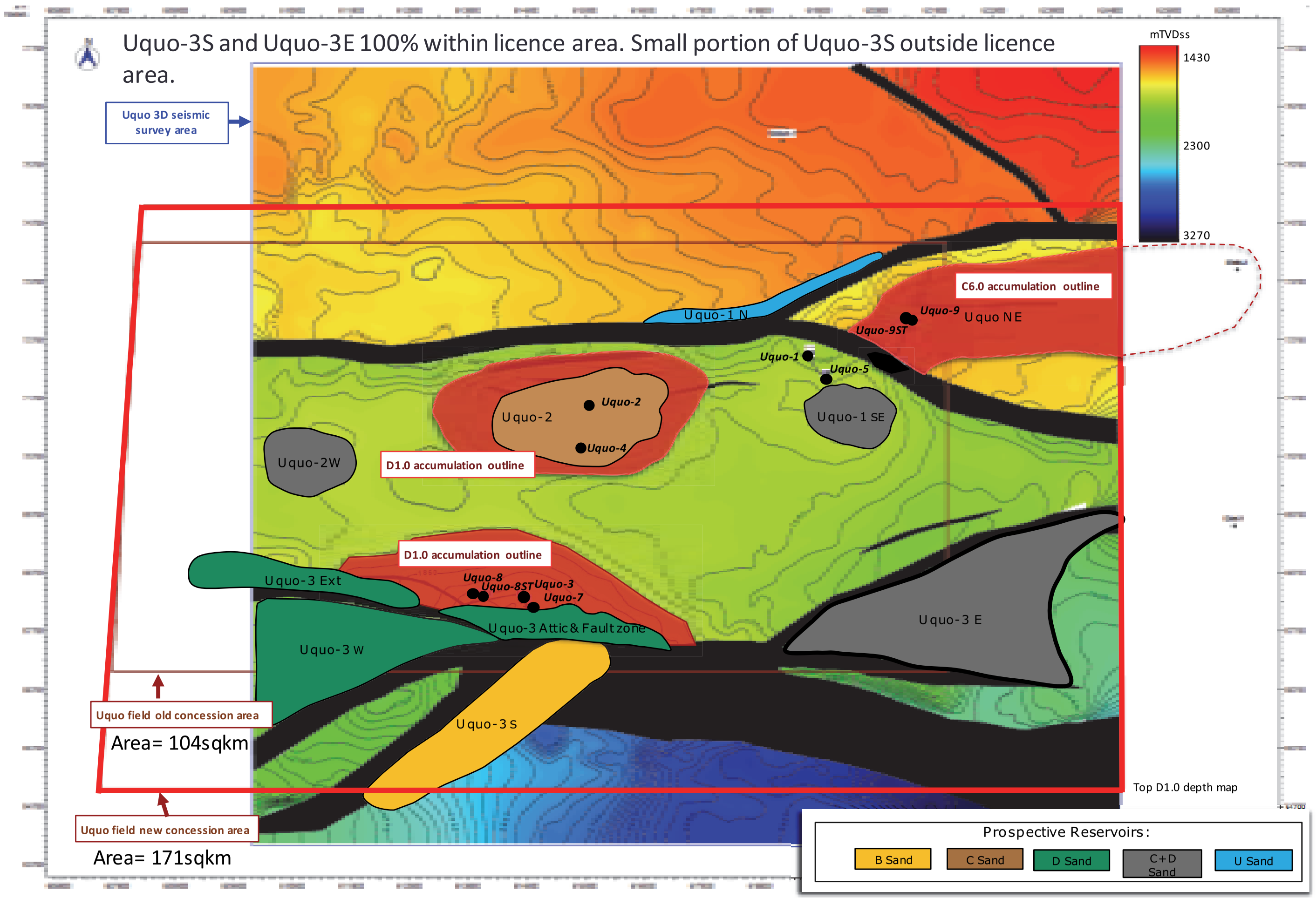
Niger Basin Stratigraphy



Source: Copyright 1999, Tuttle et al, U.S. Geological Survey

Figure 2.2

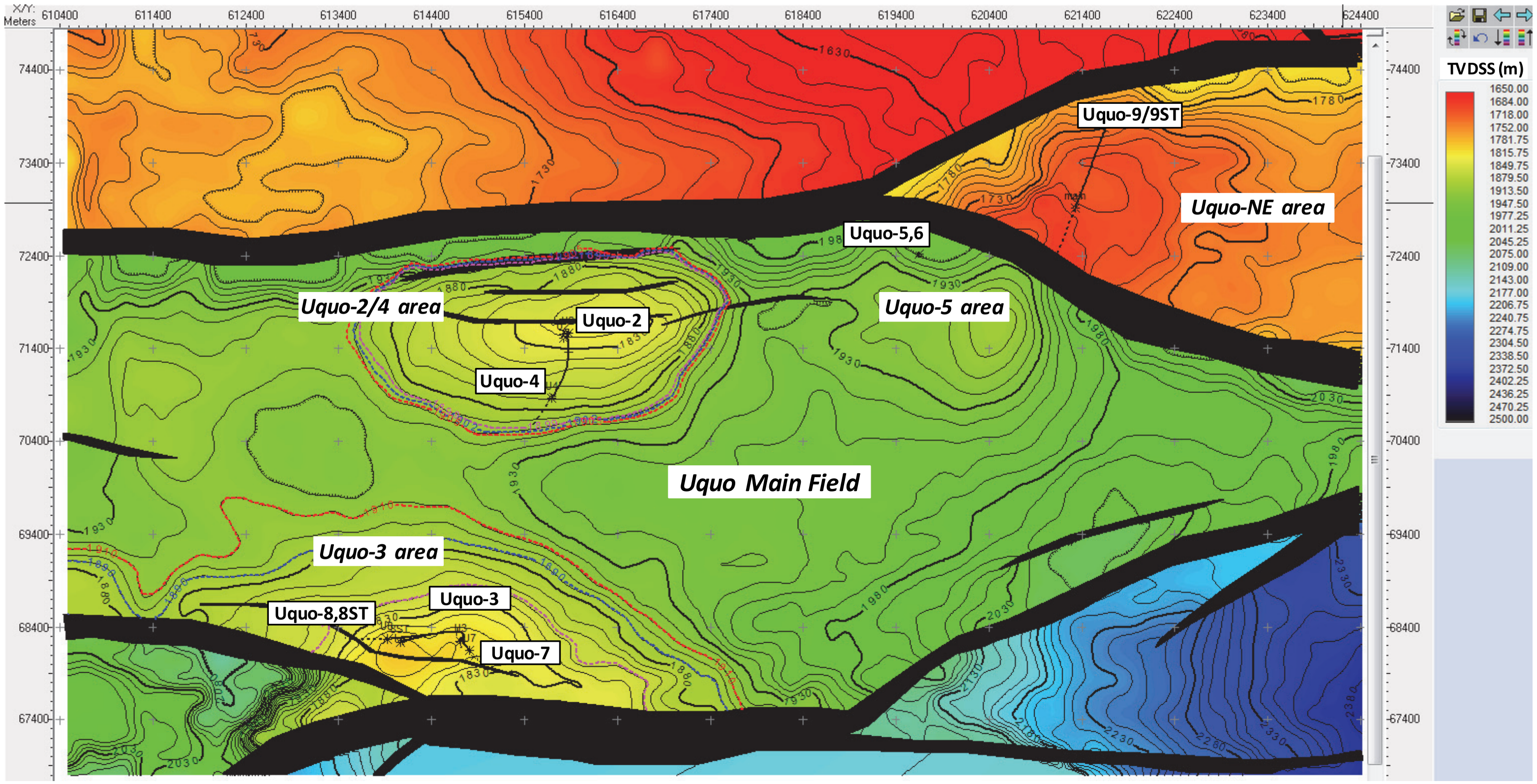
Uquo Area – Uquo Marginal Field, Discovery and Prospects – Licence Area Extended 2015



Source: Seven Energy 2017

Figure 3.1

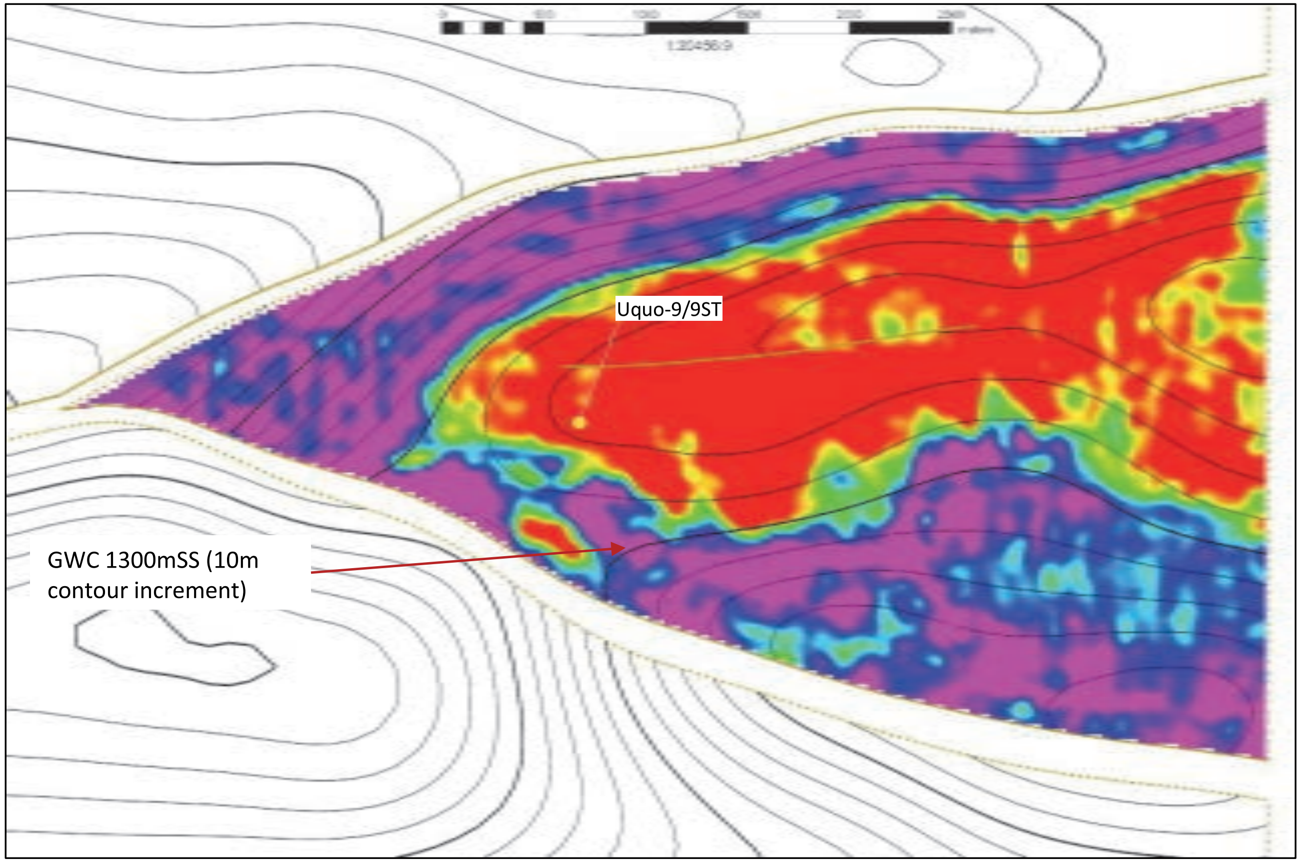
Uquo Marginal Field Top D1.0 Depth Structure Map



Source: Seven Energy 2017

Figure 3.2

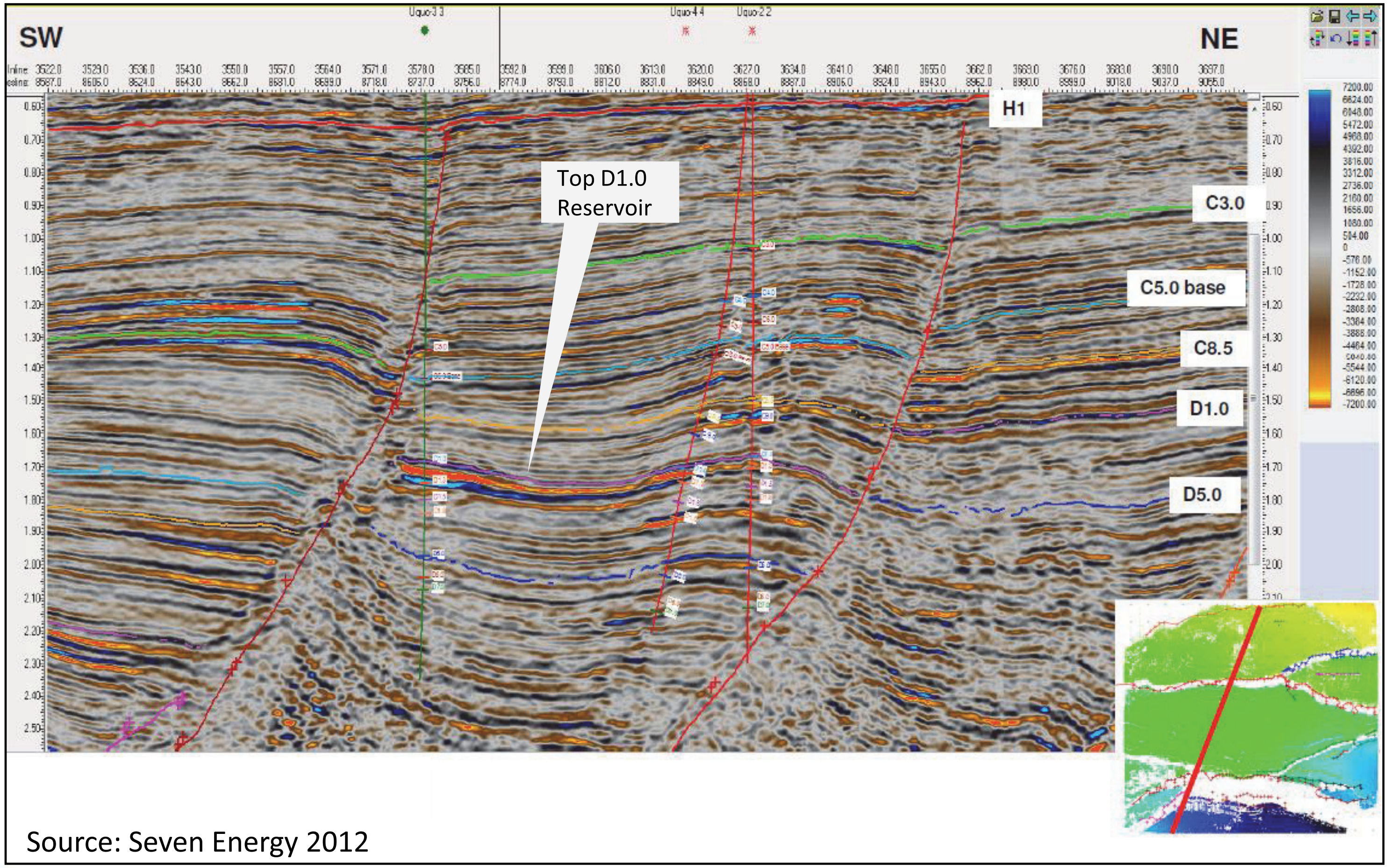
Uquo NE Discovery Top C6.0 Depth Map and RMS Amplitude Map



Source: Seven Energy 2017

Figure 3.3

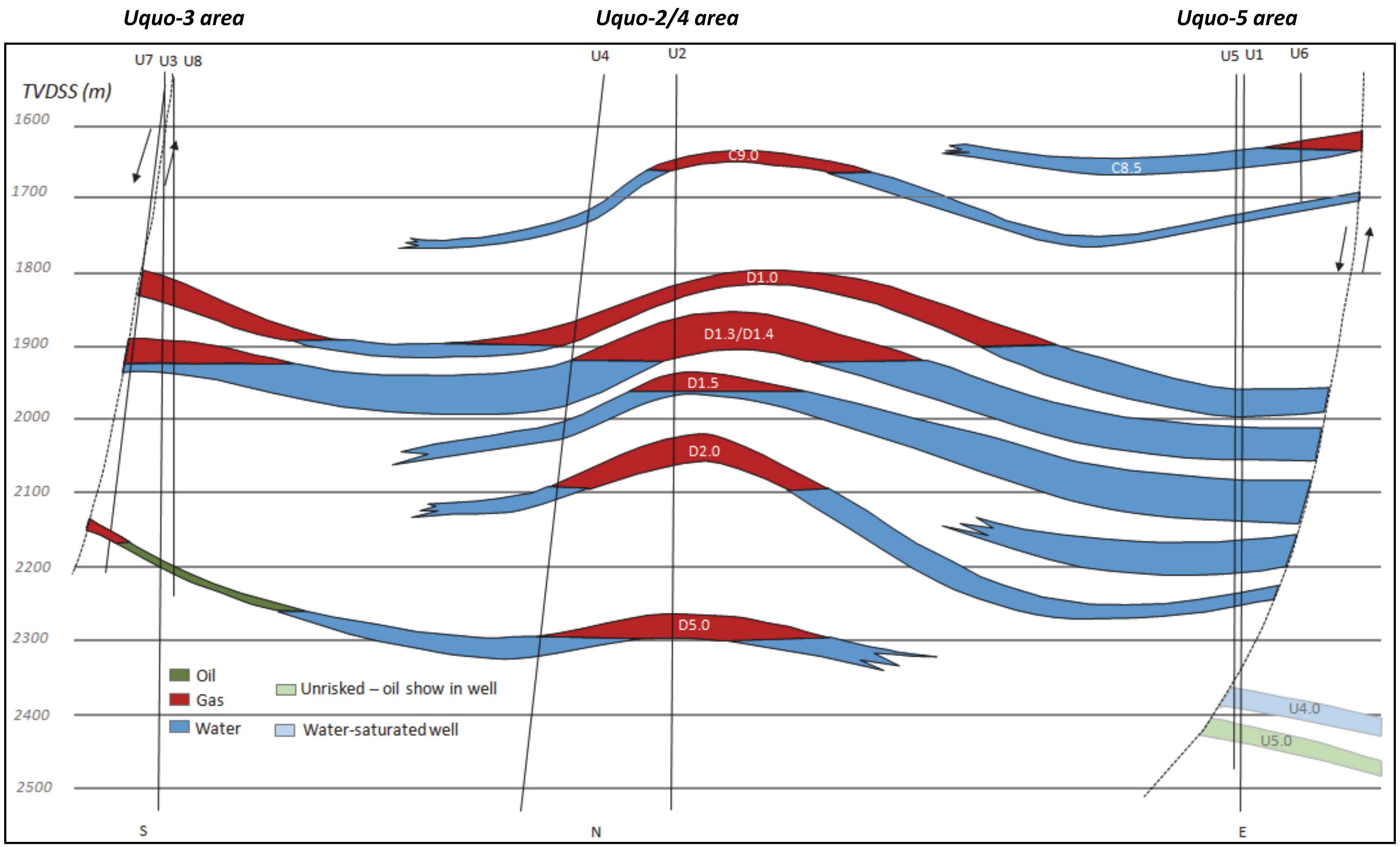
Uquo Marginal Field Northeast-Southwest Seismic Line through Uquo-3, -4 and -2



Source: Seven Energy 2012

Figure 3.4

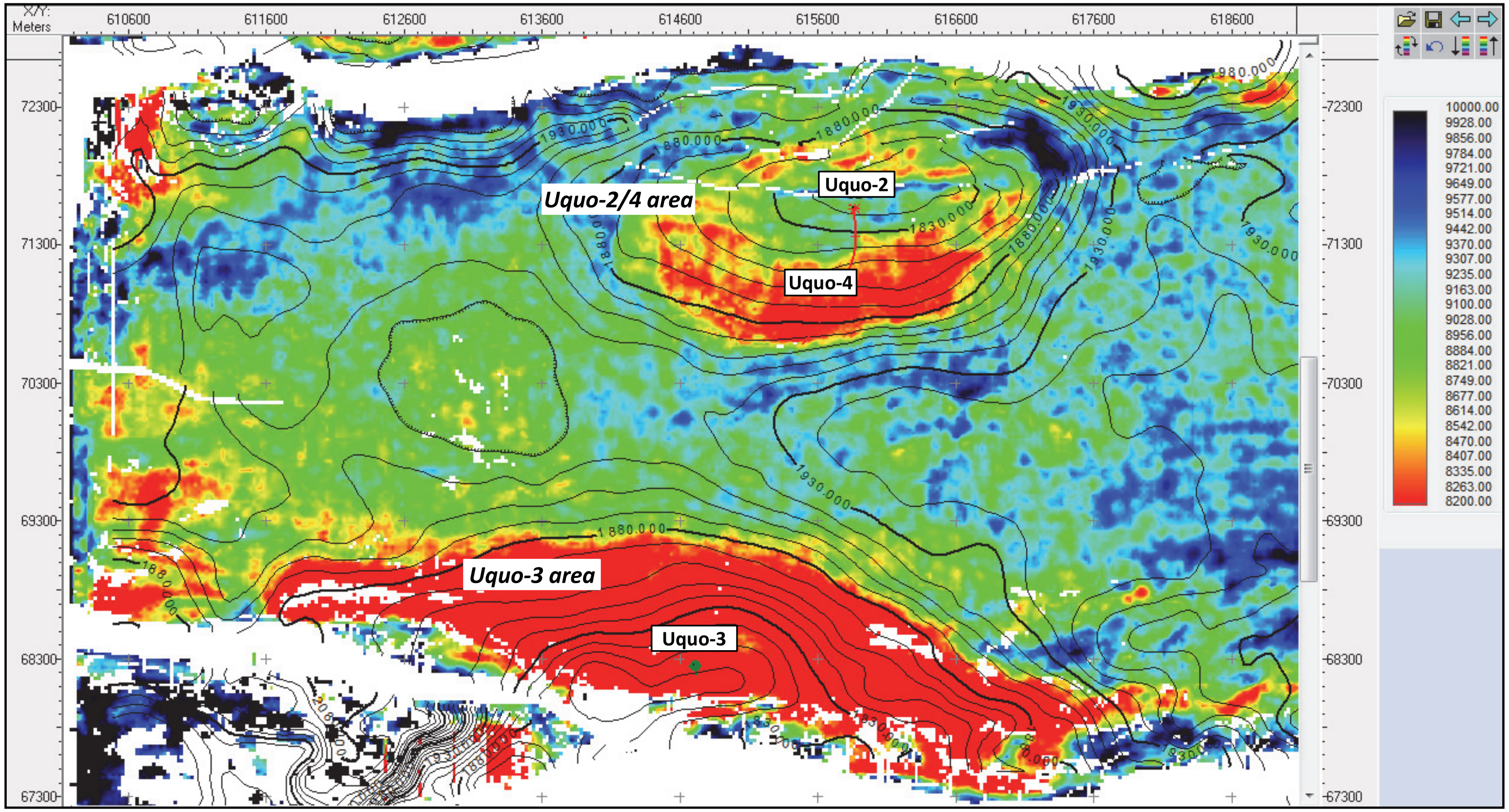
Uquo Marginal Field Schematic Cross Section with Hydrocarbon-Water Contacts



Source: Seven Energy 2017

Figure 3.5

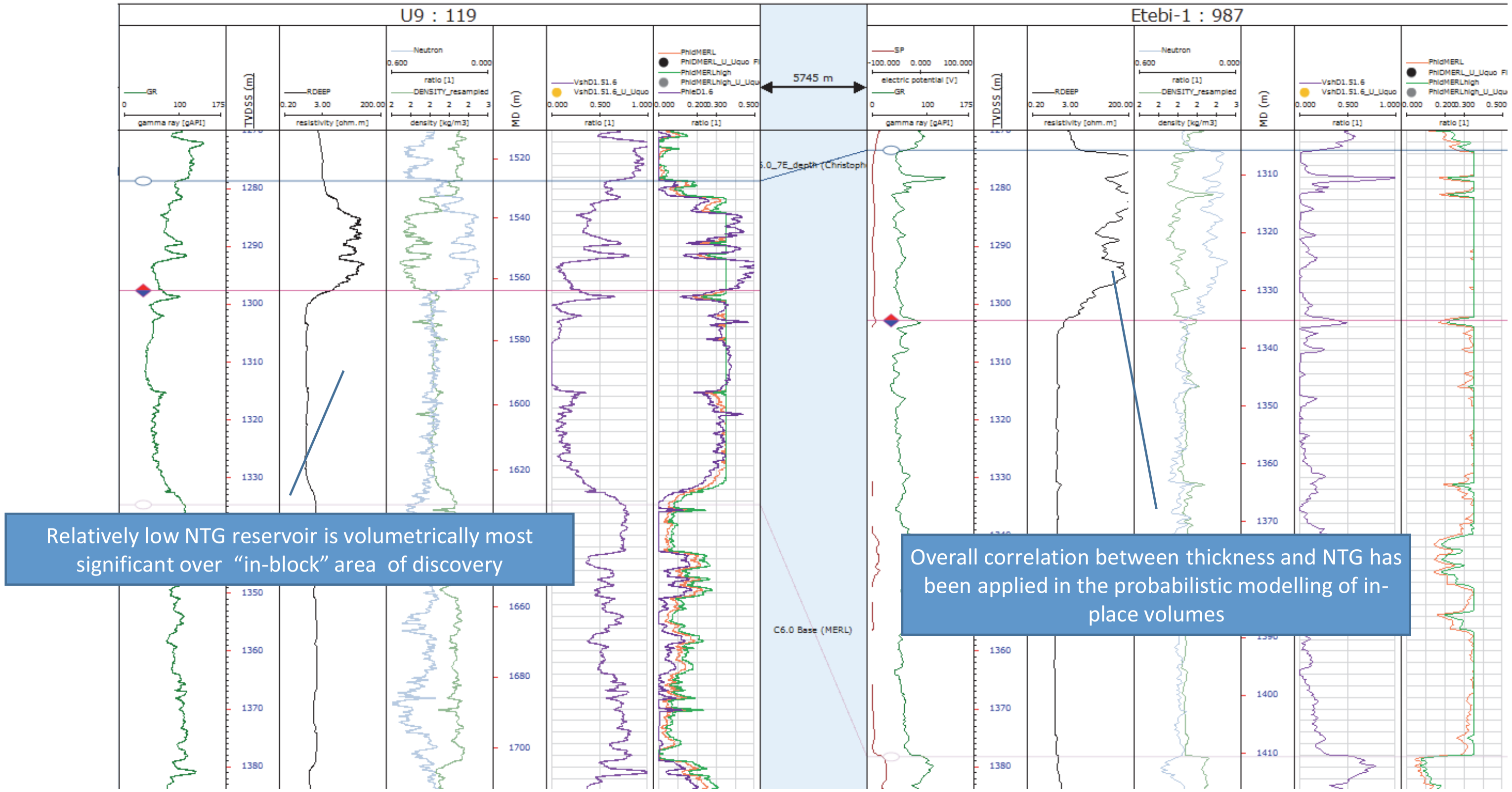
Uquo Marginal Field Top D1.0 Depth Structure with Relative Acoustic Impedance Extraction



Source: Seven Energy 2017

Figure 3.6

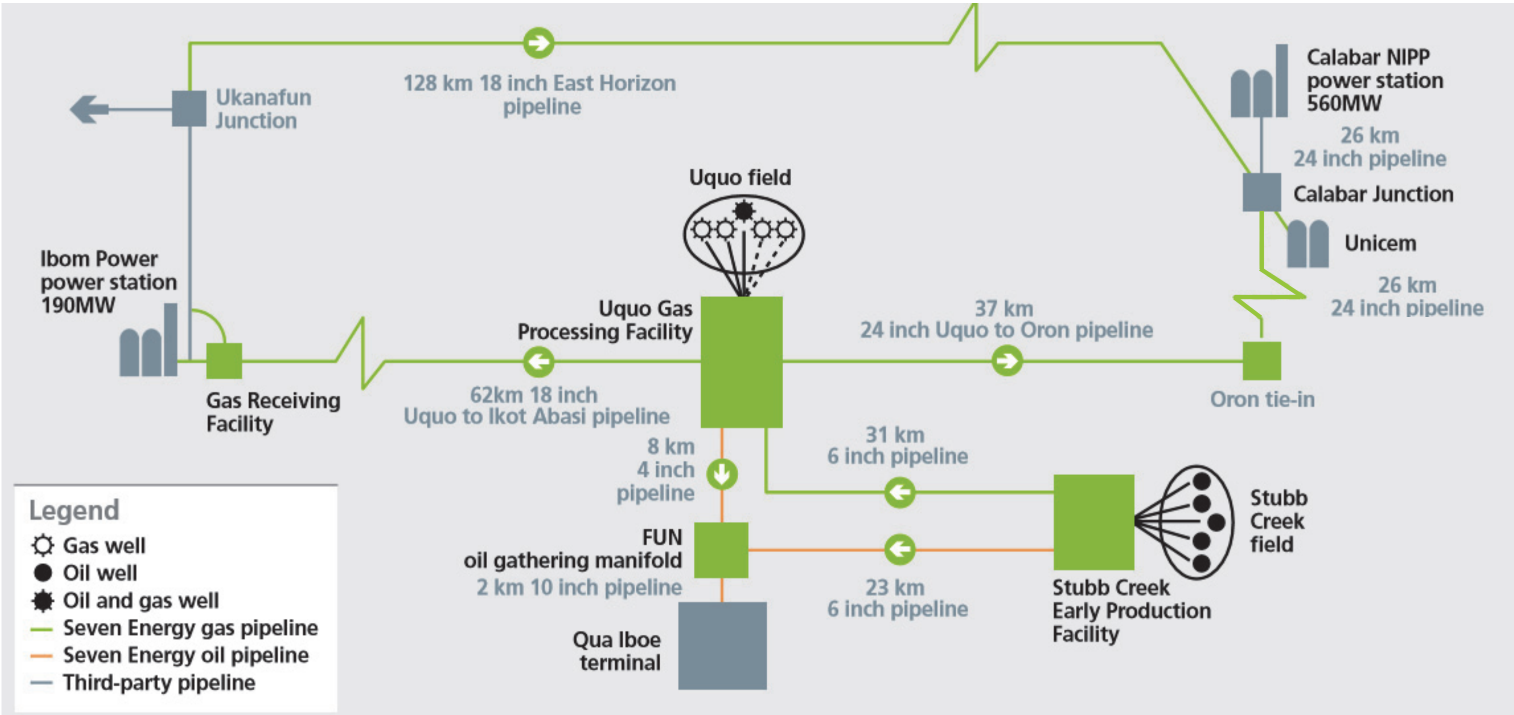
Uquo Marginal Field Top C6.0 Petrophysical Logs in Uquo-9 (left) and Etebi-1 (right) Wells



Source: Adapted from Savannah 2017

Figure 3.7

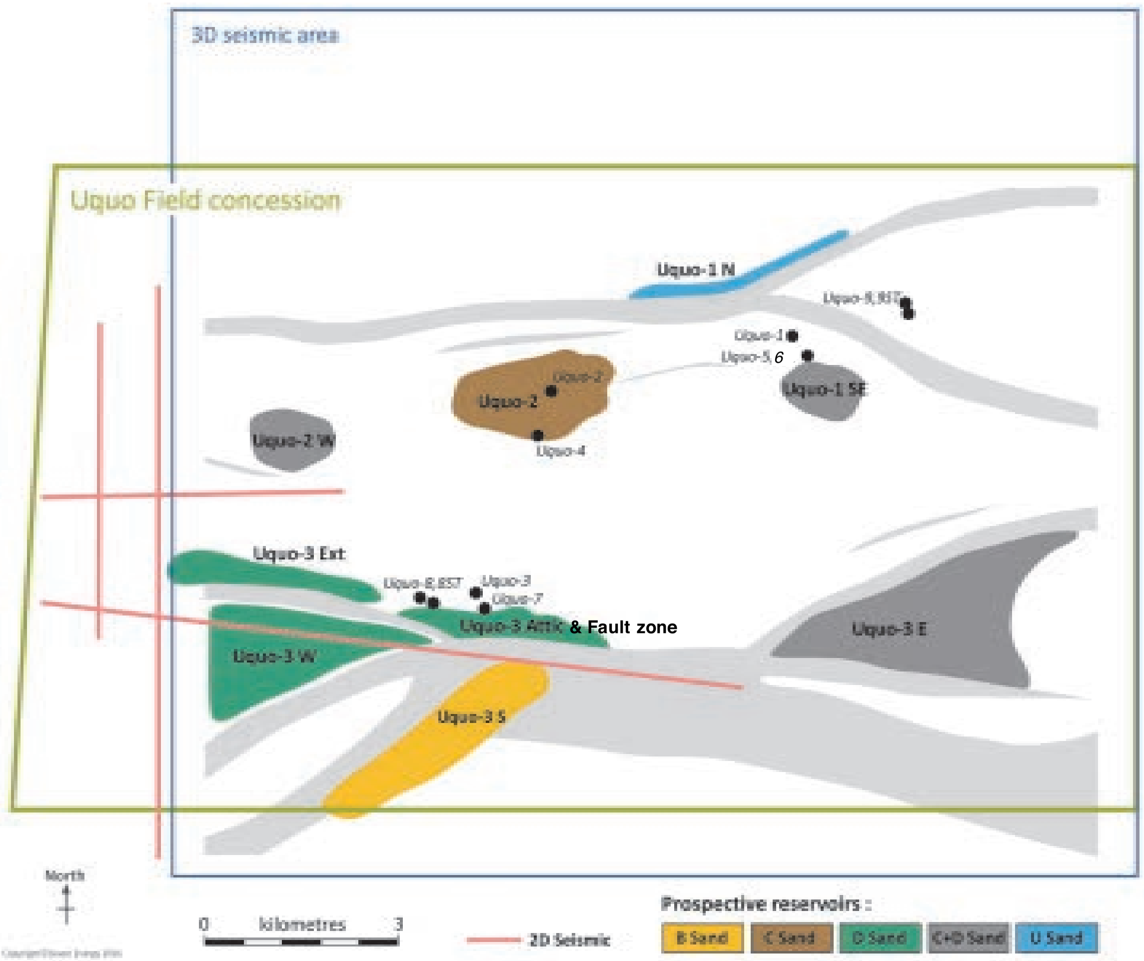
South East Nigeria Infrastructure



Source: Seven Energy 2017

Figure 3.8

Uquo Area Prospect Map

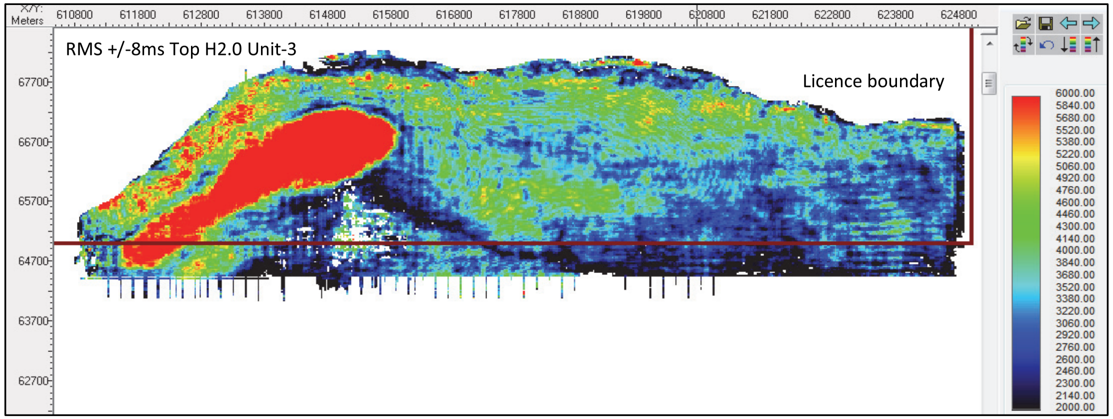


Source: Seven Energy 2017

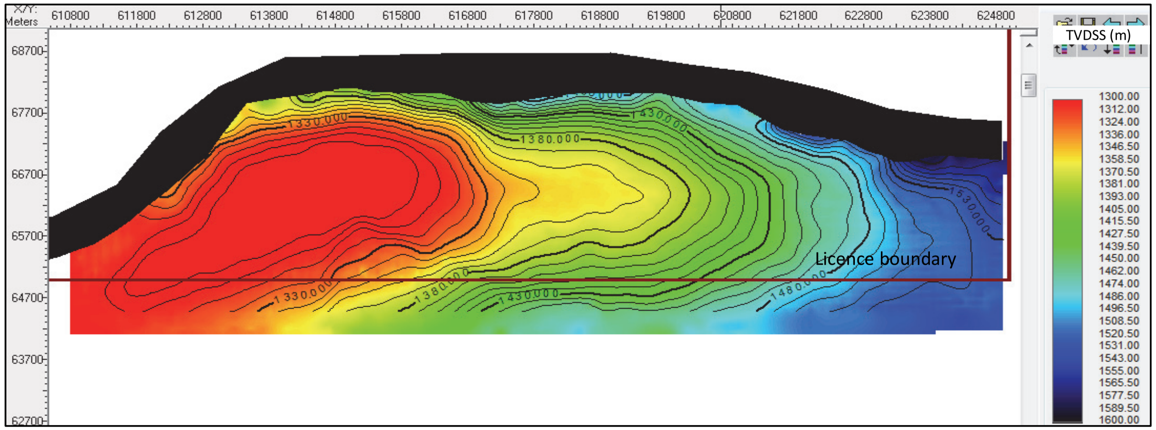
Figure 3.9

Uquo-3S Prospect Top H2.0 Unit-3 Depth Map and RMS Amplitude

Uquo-3S – RMS amplitude map - Top H2.0 Unit-3 sand



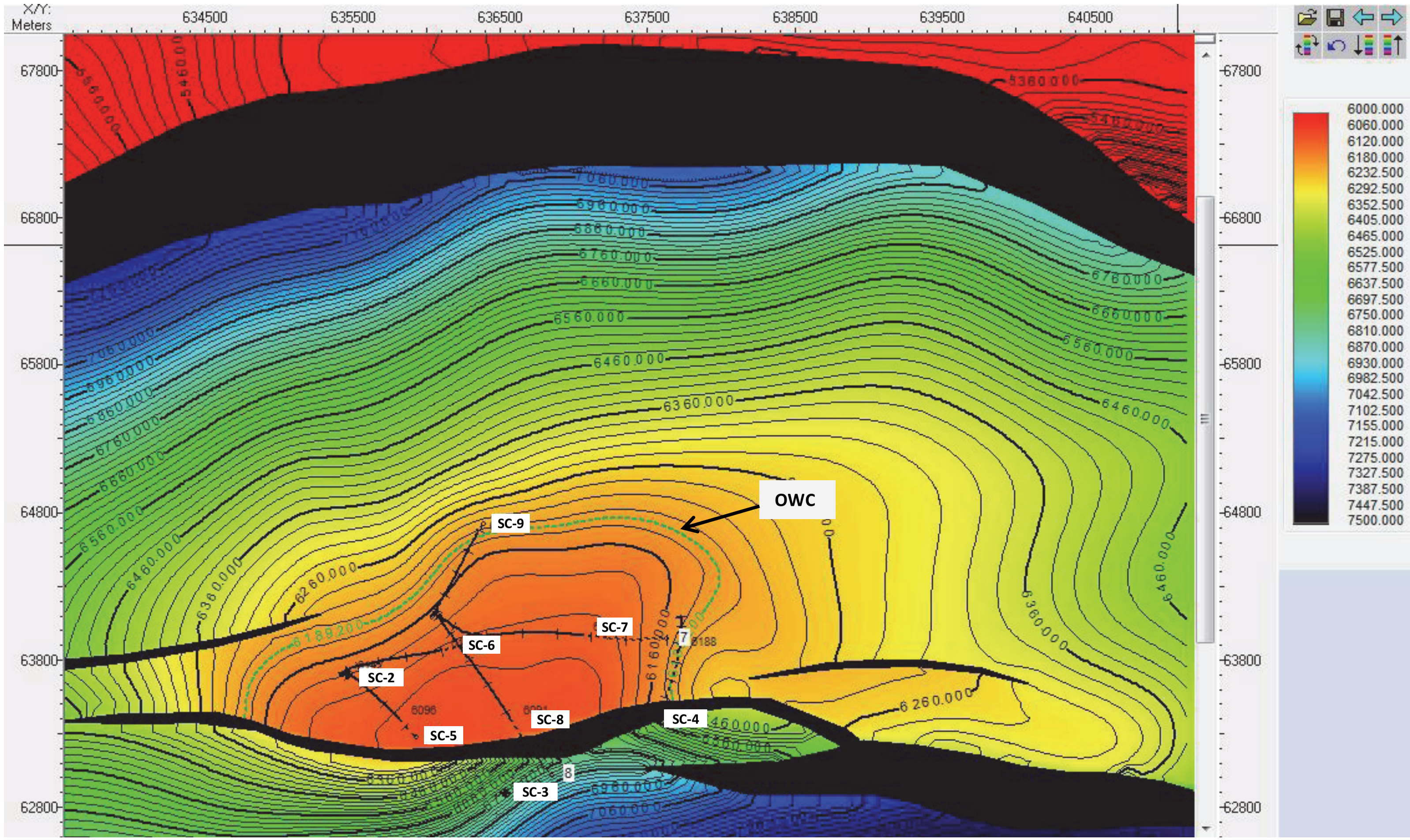
Uquo-3S – Top H2.0 Unit-3 sand depth map



Source: Seven Energy 2016

Figure 3.10

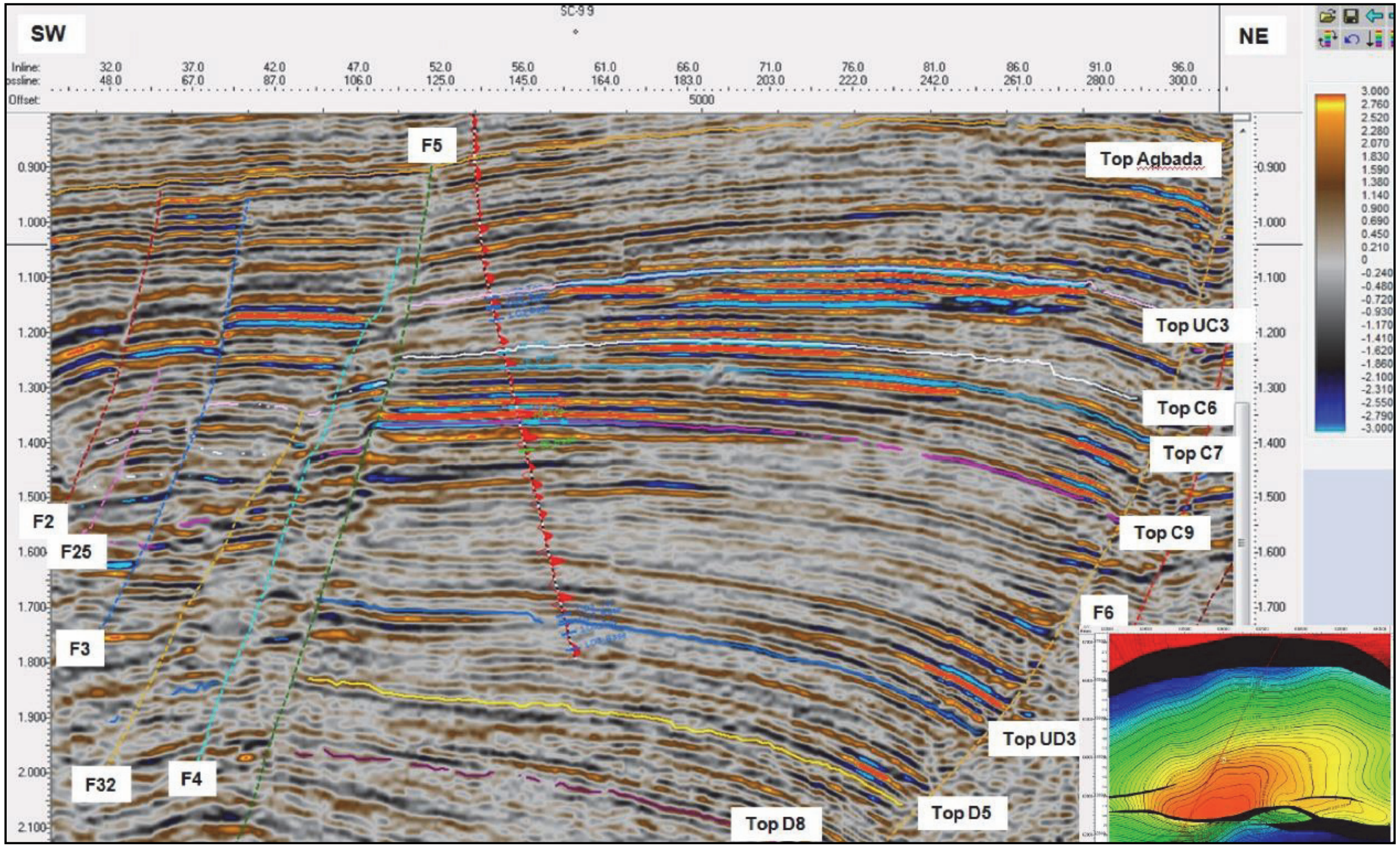
Stubb Creek Marginal Field Top UD3 Depth Map



Source: Seven Energy 2017

Figure 3.11

Stubb Creek Marginal Field Arbitrary Line through SC-9

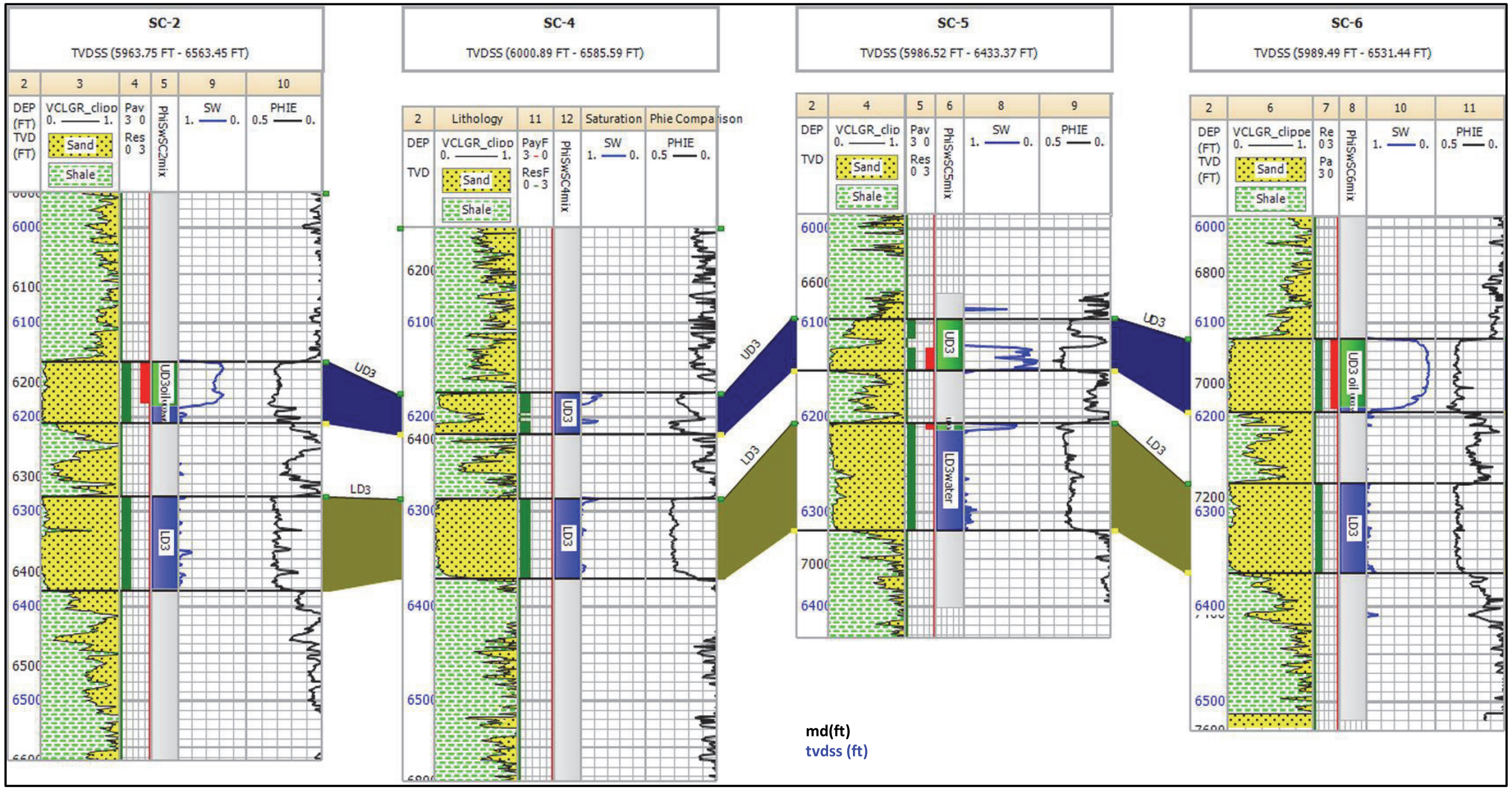


Good correlation between well synthetic and UD3 horizon

Source: Seven Energy 2012

Figure 3.12

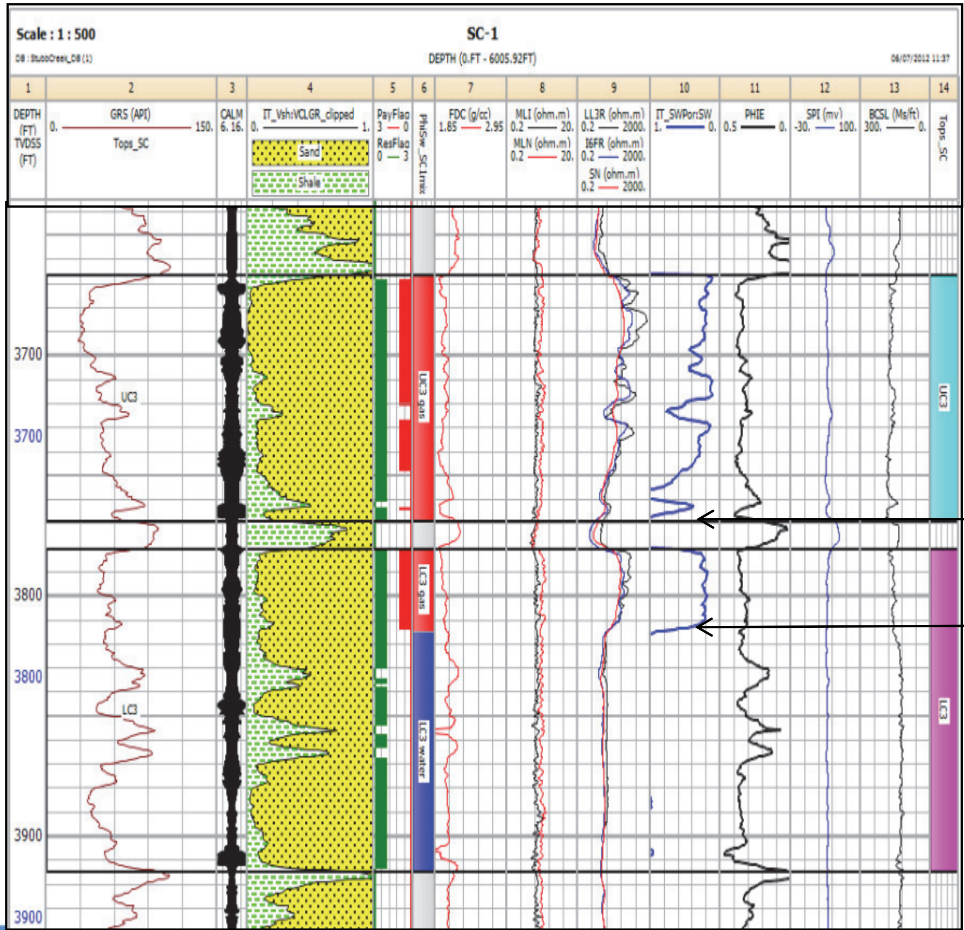
Stubb Creek Marginal Field D3 Sands Well Correlation



Source: Seven Energy 2017

Figure 3.13

Stubb Creek Marginal Field C3 Sands in SC-1



Zone Name	Gross	Net	N/G	Av Phi	Av Sw
UC3	102.4	98.5	0.96	0.34	0.37
LC3	134.0	119.0	0.89	0.33	0.78

SC-1 Net reservoir average properties (cut-offs: PHIE>0.1 & Vsh<0.4)

Zone Name	Gross	Net	N/G	Av Phi	Av Sw
UC3	102.4	73.8	0.72	0.35	0.26
LC3	134.0	32.8	0.25	0.34	0.24

SC-1 Net pay average properties (cut-offs: PHIE>0.1, Vsh<0.4 & Sw<0.5)

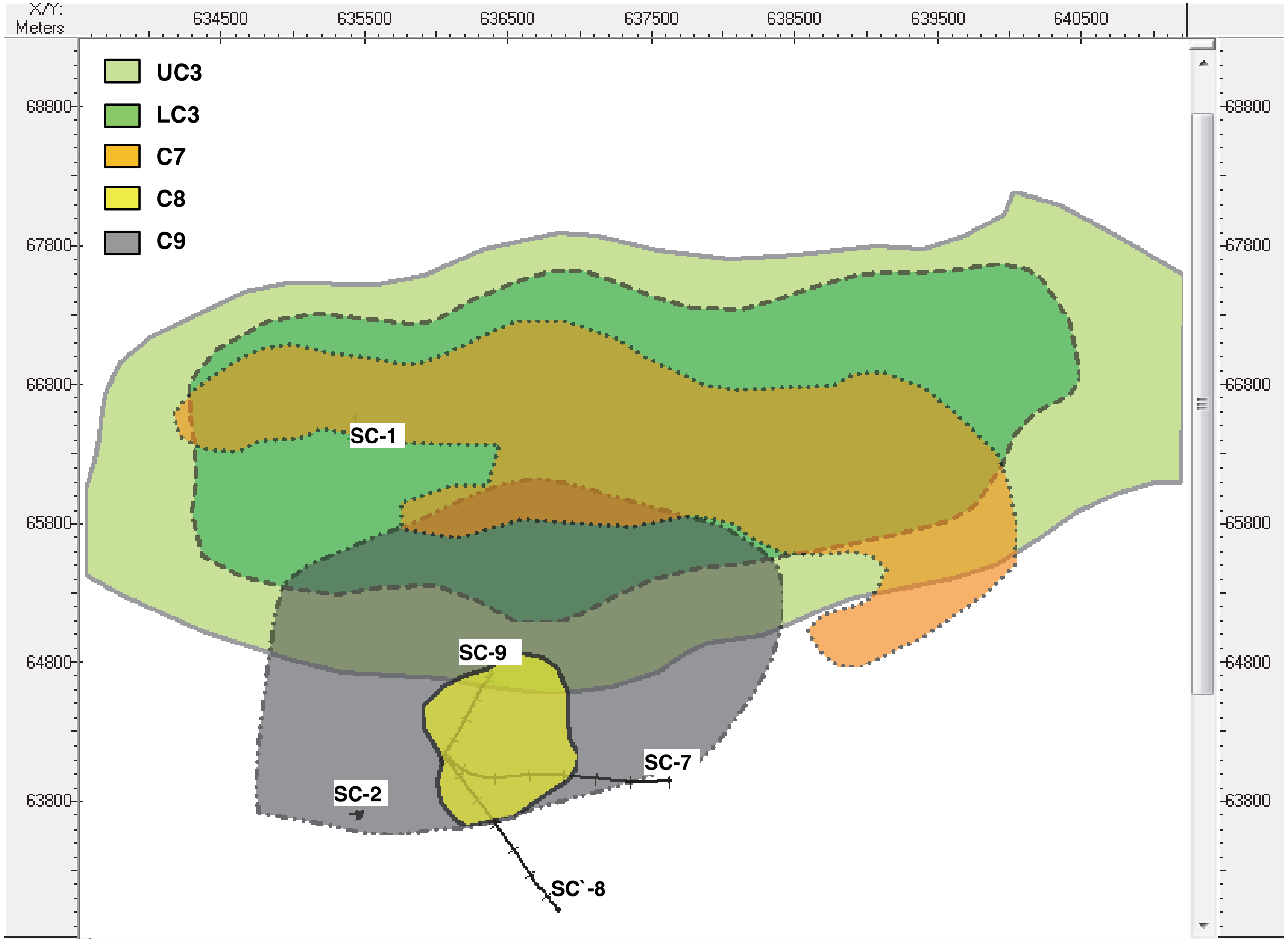
GDT 3,737 ft tvdss in UC3

GWC 3,780 ft tvdss in LC3

Source: Seven Energy 2012

Figure 3.14

Stubb Creek Marginal Field C Sands – Extent of Gas Accumulation by Reservoir

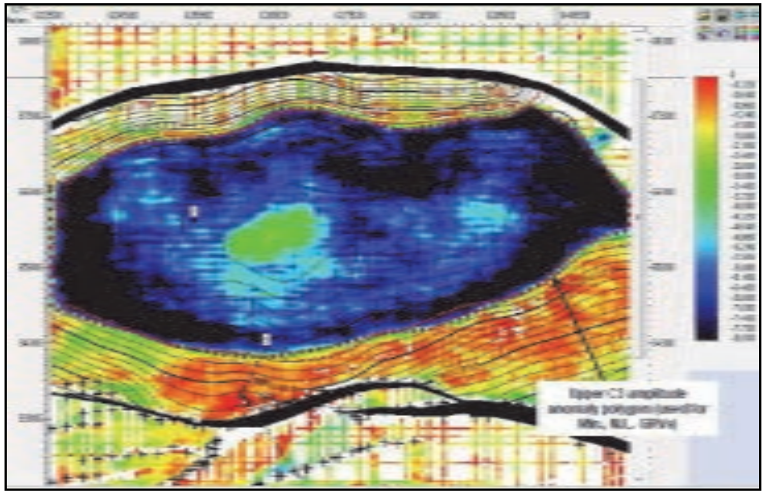


Source: Seven Energy 2017

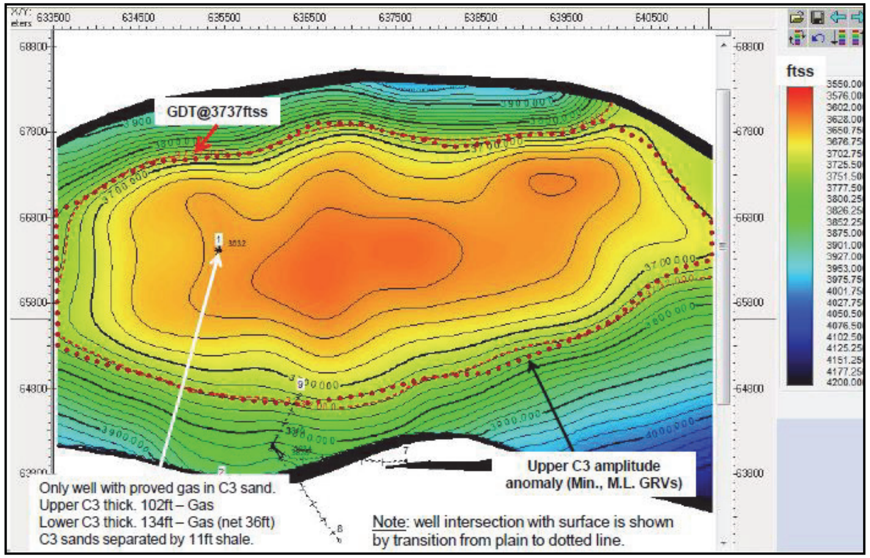
Figure 3.15

Stubb Creek Marginal Field Top Upper C3 Depth Map and Amplitude Extraction

Top UC3 Sand Minimum Amplitude Extraction (+/- 8ms)



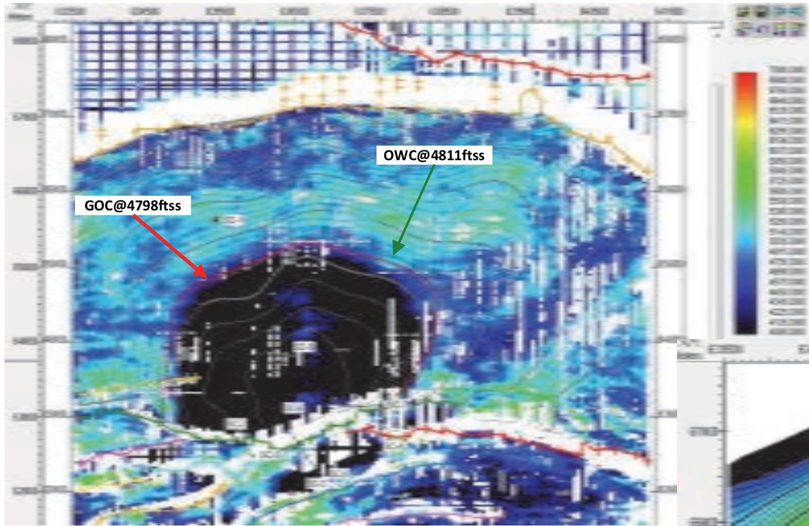
Top Upper C3 Depth Map



Source: Seven Energy 2017

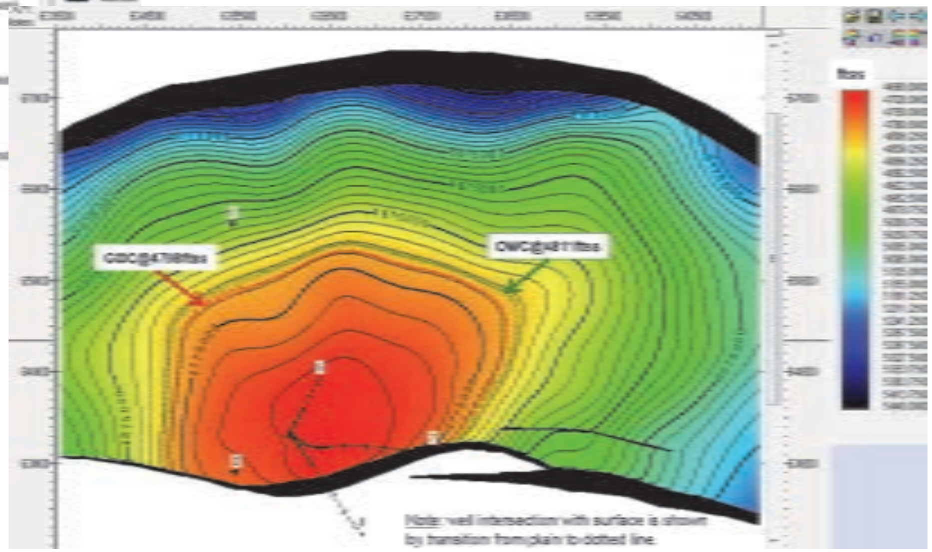
Figure 3.16

Stubb Creek Marginal Field Top C9 Depth Map and Acoustic Impedance Extraction



Top C9 Sand - Minimum Relative Acoustic Impedance Extraction (+ 8ms)

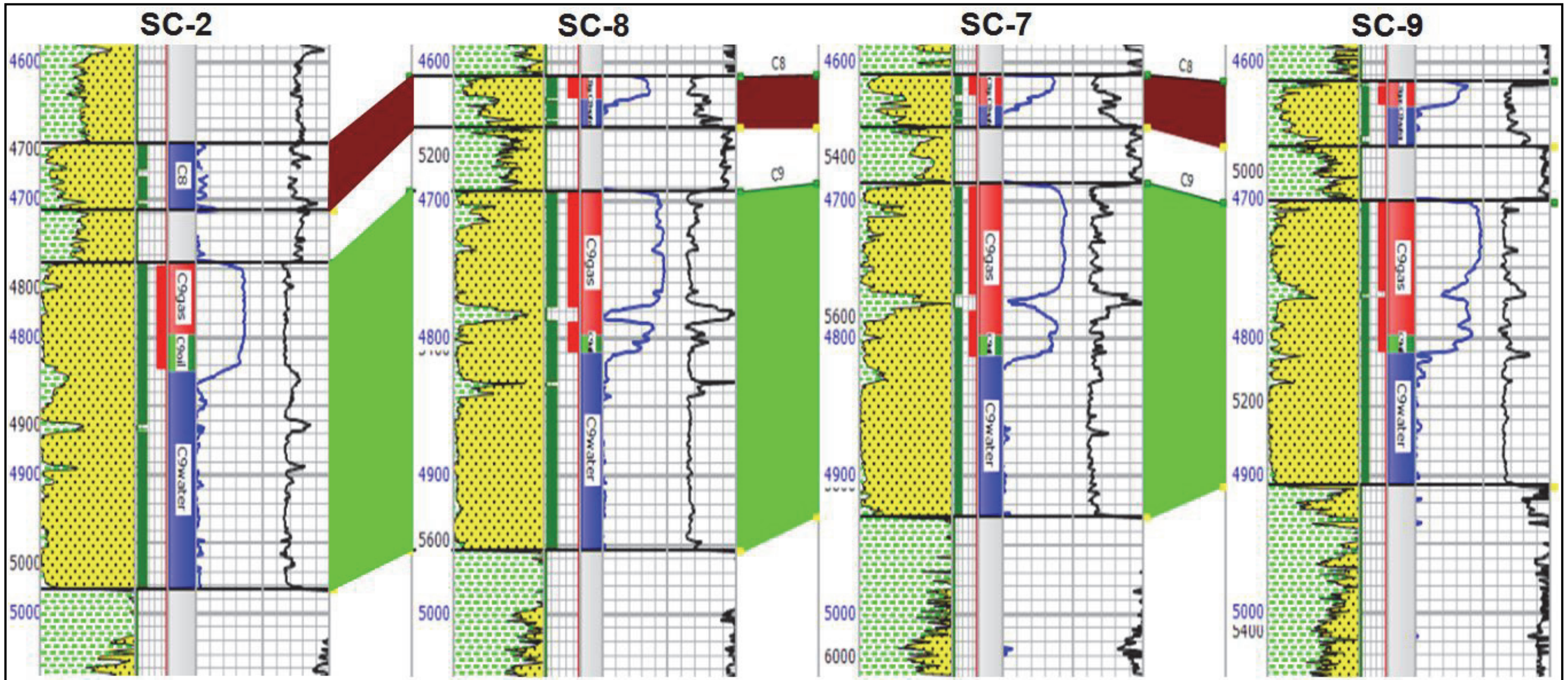
Top C9 Depth Map



Source: Seven Energy 2017

Figure 3.17

Stubb Creek Marginal Field C9 Sands Well Correlation and Petrophysics



Zone Name	Av Gross	Av Net	Av N/G	Av Phi	Av Sw
C9	236.3	226.6	0.96	0.33	0.64

SC-2, 7, 8 & 9 Net reservoir average properties (cut-offs: PHIE>0.1 & Vsh<0.4)

Zone Name	Av Gross	Av Net	Av N/G	Av Phi	Av Sw
C9	236.3	96.6	0.42	0.33	0.21

SC-1, 7, 8 & 9 Net pay average properties (cut-offs: PHIE>0.1, Vsh<0.4 & Sw<0.5)

Figure 3.18

Source: Seven Energy 2012

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E14 4BB

For the attention of Andrew Knott

21 December 2017

Dear Sir

COMPETENT PERSONS REPORT FOR THE R1/R2 AND R3/R4 LICENCE AREAS, NIGER

CGG GeoConsulting is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG GeoConsulting has prepared this Competent Persons Report (CPR) for Savannah Petroleum PLC, Strand Hanson Ltd. and Barclays Bank PLC, for use in connection with the Company's (or the Company's holding Company's) re-admission to trading on AIM. This CPR is a technical and economic evaluation and has been undertaken by CGG GeoConsulting personnel that have in excess of ten years' experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a time based fee basis and products on a licence basis, CGG GeoConsulting has no commercial arrangement or interest with Savannah Petroleum PLC or the assets which are the subject of the CPR or any other person or company involved in the interests. CGG GeoConsulting has provided an independent assessment from Savannah Petroleum PLC.

The copyright of this CPR document remains the property of CGG GeoConsulting. It has been provided to Savannah Petroleum PLC for the purpose of its re-admission to trading on AIM and its inclusion in the related AIM Admission Document and disclosure on the Savannah Group's website in accordance with the AIM Rules (these together being the "Purpose"). CGG GeoConsulting agrees to disclose the enclosed CPR to Savannah Petroleum PLC for the Purpose. The recipient should also note that this document is being

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provided on the express terms that, other than for the Purpose, it is not to be copied in part or as a whole, used or disclosed in any manner or by any means unless as authorised in writing by GeoConsulting. Notwithstanding these general conditions, CGG GeoConsulting additionally agrees to the publication of the CPR document, in full, on the Savannah Group's website in accordance with AIM rules.

Andrew Webb

Mr Andrew Webb has supervised the preparation of this CPR. Andrew is the Manager of the Petroleum Reservoir & Economics Group at CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 29 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisitions and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

Rob Crossley

Dr Rob Crossley has provided petroleum geological inputs to this CPR. He is Chief Geologist in the Geoconsulting Group at CGG, having joined the company as sedimentologist in 1986. He graduated in 1976 with a PhD jointly from the Universities of London and Lancaster. He has particular expertise in the geology of petroleum systems in rift basins and now has 31 years' experience in the upstream oil and gas industry. Rob's involvement with asset evaluation projects has been global but focused predominately in Europe, Africa, Middle East, Far East and South America.

John Clure

John graduated with a degree in geology and has over 48 years' experience in the upstream oil and gas industry. He worked 21 years with Conoco in various parts of the world doing exploration and development projects. His work with Conoco included several years in the Advance Exploration Group evaluating acquisition of assets. He jointly formed an oil company which acquired 8 blocks in the central North Sea which was successfully sold to a larger company. Over the past 6 years he has worked on numerous asset evaluations with CGG. He is a Fellow of the Geological Society and an AAPG Certified Petroleum Geologist.

Usman Mohammad

Usman gained an MSc in Petroleum Engineering from Heriot Watt University and Member status with Energy Institute UK. He has 10 years of Reservoir and Production Engineer experience. He has worked as operational reservoir engineer with BP (onshore, Pakistan) and Dana Petroleum UK (offshore, UK). His previous experience was Production Engineer with Axis Well Technology in Aberdeen UK where he has worked on Production Enhancement and Field Development Planning projects. He has a thorough understanding of classical and numerical reservoir engineering. He is a member of the Society of Petroleum Engineers and Prince2 Registered Practitioner.

Peter Wright

Peter gained an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies, and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

Yours faithfully,

Andrew Webb
Manager, Petroleum Reservoir and Economics
Reservoir Consulting Services
GeoConsulting
Enclosed : Competent Persons Report

CGG Services (UK) Limited

COMPETENT PERSONS REPORT
R1/R2 and R3/R4 Licence Areas, Niger

FOR
Savannah Petroleum PLC
Strand Hanson Limited
Barclays Bank

CGG Services (UK) Limited Reference No: BP510
October 2017

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CGG GeoConsulting

DISCLAIMER AND CONDITIONS OF USAGE

Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between 10 and 40 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves, CPR work and in African rift basins.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Petroleum PLC or the assets, which are the subject of the report or any other person or company involved in the interests.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG has used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report. CGG has estimated the degree of this uncertainty to calculate the range of petroleum initially in place and recoverable using the SPE Petroleum Resource Management System standard (PRMS) as set out by the SPE/SPEE/AAPG/WPC as the internationally recognised standard required by the AIM Note.

CGG has independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where we judge it appropriate. CGG has carried out economic modelling based on their forecasts of costs and production. The capital and operating costs have been combined with production forecasts based on the reserves or resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG has valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets CGG has used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

The assessment is based on information provided by the Niger Ministry of Energy and Petroleum to Savannah Petroleum PLC, and on information in previous CGG in-house studies of African rift systems. CGG has relied on Savannah Petroleum PLC for validation of the accuracy and completeness of the data set provided. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Petroleum PLC has in the Properties, as communicated by Savannah Petroleum PLC. CGG has not verified nor do they make any warrant as to Savannah Petroleum PLC's interest in the Properties.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserve; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the organisation, Savannah Petroleum PLC.

CGG affirm that from the as-of date of this report, 31st October 2017, that 1) there are no matters known to CGG that would require a change to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Savannah Petroleum PLC.

This report has been compiled in accordance with the guidelines on the scope and content of a Competent Persons' Report as set out in the AIM Note "Guidance for Mining and Oil and Gas Companies, June 2009" for the purpose of inclusion within an AIM Admission document.

Conditions of Usage

The report was compiled during the period June-August 2017 with the effective cut-off date for inclusion of data being 31st October 2017. The effective date for valuation reporting is 1st January 2018. Should substantive new data or facts become available then the report should be updated to incorporate all recent data.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by Savannah Petroleum PLC for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose), this report is made. Any use made of the report shall be solely based on Savannah Petroleum PLC's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

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The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

CGG Services (UK) Limited Reference No: BP510				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
06	21st December 2017	PW	AW	Final

Date	Originator	Checked & Approved
Signed:		

Prepared for:	Prepared By:
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EXECUTIVE SUMMARY

At the request of Savannah Petroleum PLC (Savannah), CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) relating to the R1/R2 and R3/R4 licence areas (the "Licence Areas") operated by Savannah in the Agadem Rift Basin (ARB), Niger.

Savannah Petroleum Niger R1/R2 S.A. is the operator of the R1/R2 and R3/R4 Licence Areas with a 100% ownership in the licences. Savannah has a 95% interest in Savannah Petroleum Niger R1/R2 S.A.

The License Areas cover an area of 13,655km^2, representing approximately 50% of the original Agadem permit which was mandatorily relinquished in July 2013 by CNPC. The Agadem Rift Basin is a part of the wider Central African Rift System in which significant oil has been discovered. In the Agadem Rift Basin, three fields are currently in production. Oil from the three fields is currently evacuated by pipeline to the Zinder refinery, located in Niger.

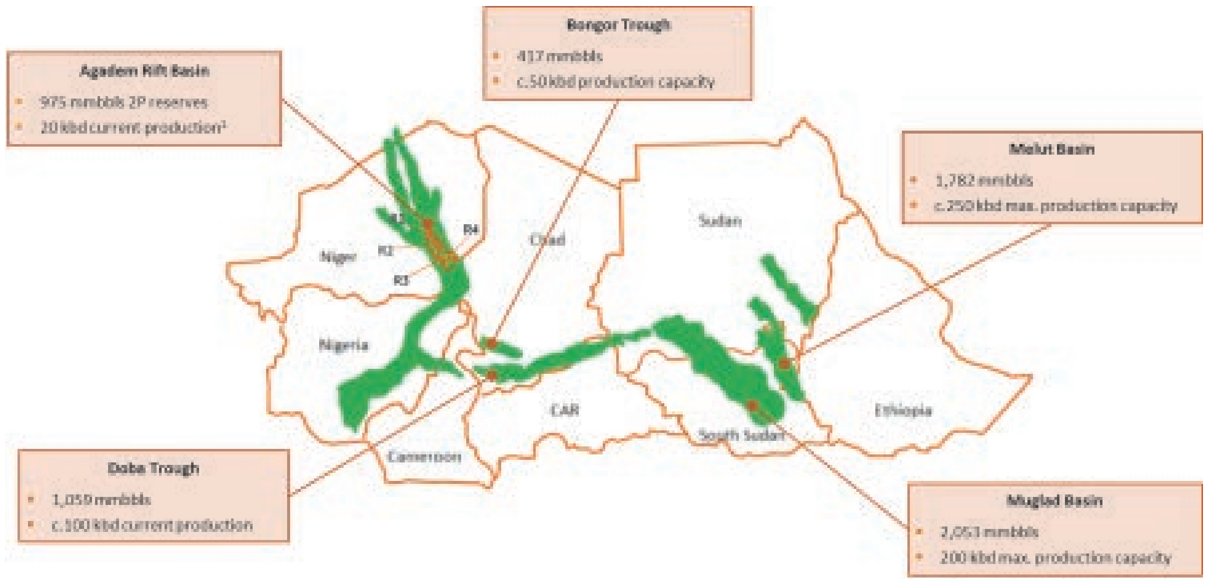

Figure 0.1 The Central African Rift System Discovered Resources

Source: Savannah

CGG has estimated STOIIP and resource volumes for nine prospects and leads from Savannah's extensive exploration portfolio, and has provided estimates of the yet-to-find resources in the Licence Areas. The nine prospects and leads have been identified as potential candidates for the initial exploration drilling campaigns across the licence areas. In addition, CGG has calculated expected recovery factors, and verified indicative economics for a notional Agadem Rift Basin development proposed by Savannah.

CGG's estimate of the unrisked STOIIP for each of the identified prospects and leads is summarised in table 0.1. The unrisked STOIIP volumes quoted combine separate "risked additions" for each prospective reservoir unit which have been summed probabilistically, taking into account their respective geological chance of success.

Table 0.1 Unrisked STOIIP by prospect or lead

	Unrisked STOIIP (MMbbls)			
Prospect/lead	**P90**	**P50**	**P10**	**Mean**
Bushiya	19	85	215	105
Amdigh	27	100	220	114
Eridal	13	48	130	62
Kunama	24	72	212	102
Kiski	8	36	130	56
Damissa	32	235	668	296
Mena	13	97	338	147
Mujia	15	135	357	167
Efital	40	205	450	228

CGG has calculated expected recovery factors for the prospects and leads from analysis of the existing producing fields in the basin. Based on this analysis and benchmarking against other analogue fields, CGG has applied recovery factors of 29%, 34% and 39% to the STOIIP figures to calculate recoverable volumes for the low, best and high resource cases respectively.

Prospective resources have been calculated by CGG in accordance with PRMS (2007) and the AIM Guidance Note for Oil and Gas Companies (2009) for the identified prospects and leads, and are summarised in the table below. Individual stratigraphic reservoir volumes have been summed probabilistically, in order to calculate an overall prospect or lead resource total.

Table 0.2 Prospective Resources Unrisked

	Unrisked Prospective Resources, MMbbl								
	Gross				Net attributable				
Prospec t / lead	**Low estimate**	**Best estimate**	**High estimate**	**Mean estimate**	**Low estimate**	**Best estimate**	**High estimate**	**Risk factor**	**Operator**
Bushiya	6	29	84	36	5	27	80	low	Savannah
Amdigh	8	34	86	39	7	32	81	low	Savannah
Eridal	4	16	51	21	3	16	48	low	Savannah
Kunama	7	25	83	35	7	23	79	low	Savannah
Kiski	2	12	51	19	2	12	48	low	Savannah
Damissa	9	80	261	101	9	76	248	low	Savannah
Mena	4	33	132	50	4	31	125	low	Savannah
Mujia	4	46	139	37	4	44	132	low	Savannah
Efital	12	70	175	77	11	66	167	low	Savannah

Notes

1. *Prospective resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from the probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *Full definitions of the Prospective Resource categories can be found in Appendix B*
5. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
6. *Risk factors: low = > 75%, medium = 25% - 75%, high = <25%*

CGG has reviewed Savannah's in-house methodology for assessing gross mean un-risked STOIIP for the selected nine prospects and leads, and found it to be reasonable. CGG has also validated Savannah's volumetric input parameters, and found them to be reasonable. CGG has further evaluated Savannah's assessment of exploration risk, and found that to be reasonable too. Although some differences do exist between CGG and Savannah, this level of disparity often results from small differences in data interpretation and calculation methodology. CGG's overall evaluation of the nine prospects and leads is slightly optimistic than that of Savannah.

CGG has conducted a separate 'yet-to-find' analysis, which estimates the quantity of oil that may ultimately be expected to be found on Savannah's licences, based on previous discoveries made in the basin. This is a proprietary methodology created by CGG and does not reflect a replication of Savannah's work. The method calculates discovered STOIIP per km^2 for areas with similar characteristics, which are then adjusted and applied to the R1/R2 and R3/R4 Licence Areas. It should be noted that these yet-to-find volumes are not linked to Savannah's planned exploration campaign. They are estimates of what could ultimately be discovered across the plays analysed, assuming a seismic and exploration drilling campaign of similar density to that employed to date. The results of this analysis are presented in the table below.

Table 0.3 Estimate of gross unrisked and risked "yet to find" resources

	Prospective resources (gross) – "yet to find" (MMBO)					
	Unrisked			Risked		
Block	**Low estimate**	**Best estimate**	**High estimate**	**Low estimate**	**Best estimate**	**High estimate**
R1/R2	1,608	4,231	6,304	639	1,682	2,505
R3/R4	1,025	2,696	4,018	433	1,139	1,698
Total	**2,632**	**6,927**	**10,322**	**1,072**	**2,821**	**4,203**

Savannah has also performed detailed conceptual studies for a 73 mmbbl cluster development of four notional discoveries in the R3 License Area, which have been reviewed by CGG and found to be reasonable. R3 is where Savannah intends to start its exploration drilling campaign and the notional discoveries are intended to approximately replicate the drilling targets. Savannah has chosen a "hub and spoke" development concept that has been used elsewhere already in the basin. The concept consists of Field Processing Facilities (FPFs) tied back to a Central Field Processing Facility (CPF). A leased Early Production Facility (EPF) is also proposed to enable a shorter schedule to first production.

It should be noted that this conceptual development solution and the associated costs and economic analysis is not directly representative of Savannah's planned exploration campaign. It represents an assumption of how any discoveries made as part of Savannah's planned exploration campaign could potentially be developed, but final development plans and work programmes will be subject to analysis of the results of Savannah's planned drilling campaign.

As the existing Nigerien refinery at Zinder is already fully supplied, incremental oil production will have to be exported. Three options for exporting production have therefore been developed by Savannah and reviewed by CGG. Descriptions of the three options and the estimated respective costs and tariffs are tabulated below.

Table 0.4 Export option summary

Export option	Max Oil rate (Stb/D)	Total Wells Drilled	Total Capex ($MM)	Field Opex ($MM)	Export tariff ($/bbl)
1. New third party 800km pipeline to connect with existing Chad-Cameroon pipeline	18,000	43	411	595	16
2. New third party 800km pipeline to Kaduna refinery, northern Nigeria	18,000	43	411	595	5
3. Existing 463km pipeline to Zinder refinery, and then trucking to Kaduna refinery, northern Nigeria	10,000	43	427	561	6

The development studies reviewed assume that, if exploration drilling is successful, first production could be achieved in late 2020, which is three years after the proposed start of the campaign. This is a fast-track program that relies on completion of export pipelines by others in two of the options being considered. The option of trucking potentially mitigates this risk and also offers a temporary early production solution for the pipeline options.

Capital and field operating costs are estimated to be approximately $6/bbl and $8/bbl respectively.

Results of the economic analysis are presented in the table below for the three options based on a $60/bbl Brent oil price escalating at 2% per year.

Table 0.5 Notional development - indicative economics at $60/bbl (net Savannah)

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
NPV0 ($MM)	801	1132	1093
NPV10 ($MM)	252	386	269
IRR (%)	32.2%	44.0%	26.1%
NPV/bbl ($)	3.6	5.5	4.1

NPV sensitivities relating to oil prices, schedule and costs have also been run, and are presented below for each option. Sensitivities have been carried out on this base case as well as a case using the Brent forward curve as 31st July 2017.

In addition, sensitivities were also carried out at $60/bbl oil price

Table 0.6 Notional development - NPV sensitivities at $60/bbl (NPV10, $MM)

Option No.	1	2	3
Description	**Cameroon pipeline**	**Kaduna pipeline**	**Kaduna trucking**
Base case ($60/bbl)	252	386	269
+30% factor on costs	171	315	190
-15% factor on costs	288	405	306
1 year delay to 1st oil	215	339	230
Oil Price -15%	174	287	189
Oil Price +15%	326	461	346
$50/bbl oil price	128	267	168

Table 0.7 Notional development - NPV sensitivities at Brent forward curve as 31st July 2017 (NPV10, $MM)

Option No.	1	2	3
Description	**Cameroon pipeline**	**Kaduna pipeline**	**Kaduna trucking**
Forward curve 31st July 2017	140	281	180
+30% factor on costs	28	203	91
-15% factor on costs	186	319	218
1 year delay to 1st oil	112	240	146
Forward curve -15%	70	203	107
Forward curve +15%	208	362	246

The breakeven oil prices that yield a 10% rate of return for each option were also determined, and are tabulated below:

Table 0.8 Breakeven oil prices by Option

Option No.	1	2	3
Description	**Cameroon pipeline**	**Kaduna pipeline**	**Kaduna trucking**
Breakeven price ($/bbl)	43	31	36

The life of field netback cash per barrel have also been calculated for each of the options per working interest barrel, 95% Savannah interest based on economic reserves and this is shown in the table in below. These netbacks are on a nominal basis.

Table 0.9 Life of field netback cash $ per barrel

Option	1	2	3
Description	**Cameroon pipeline**	**Kaduna pipeline**	**Kaduna trucking**
Transportation	20.5	6.4	8.4
Opex/overheads	11.3	11.3	11.4
Capex/abandonment	7.6	7.6	7.8
Government take/royalty	22.3	31.6	31.5
Netback	11.5	16.2	16.5

INTRODUCTION

1.1 Overview

The R1/R2 and R3/R4 License Areas are located in the Agadem Rift Basin in South East Niger. The License Areas cover a c.13,655km² area, representing approximately 50% of the original Agadem permit which was mandatorily relinquished by CNPC in July 2013. The location of the assets under consideration is provided in Figure 1.1:

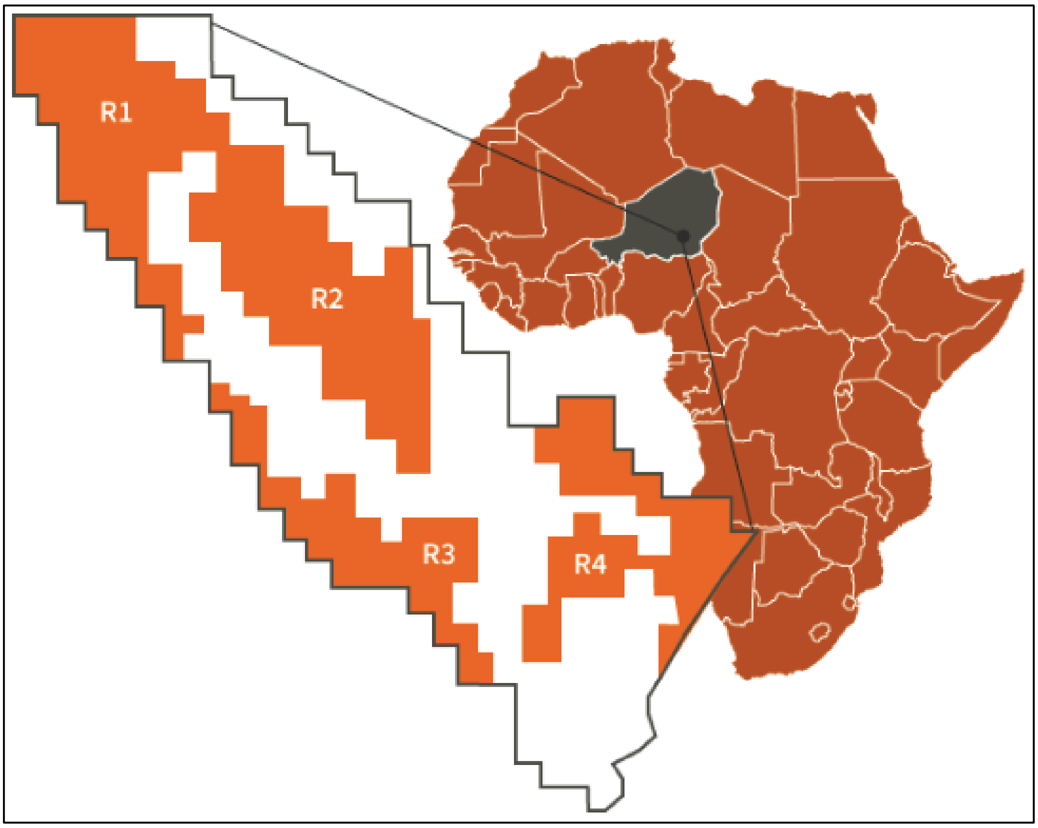

Figure 0.2 Map showing location of the assets[1]

Savannah's licences are situated in the Mesozoic to Cenozoic Agadem Rift Basin of eastern Niger. The Agadem Rift Basin (ARB) is comparable in scale to the North Sea rift system. The rift basins of Niger are part of the Central African Rift System. The Central African Rift System is a proven hydrocarbon province in Niger, Chad, Sudan and South Sudan. Topography in the Licence Areas is relatively flat and although it is a desert there are

[1] http://www.savannah-petroleum.com/en/location.php (Dated: 25th July, 2017)

no significant mobile sand dunes. The area is c.200 km away from the nearest major population centres. Wells drilled to date have been vertical or slightly deviated and to the best of our knowledge have been completed using industry standard drilling procedures and equipment.

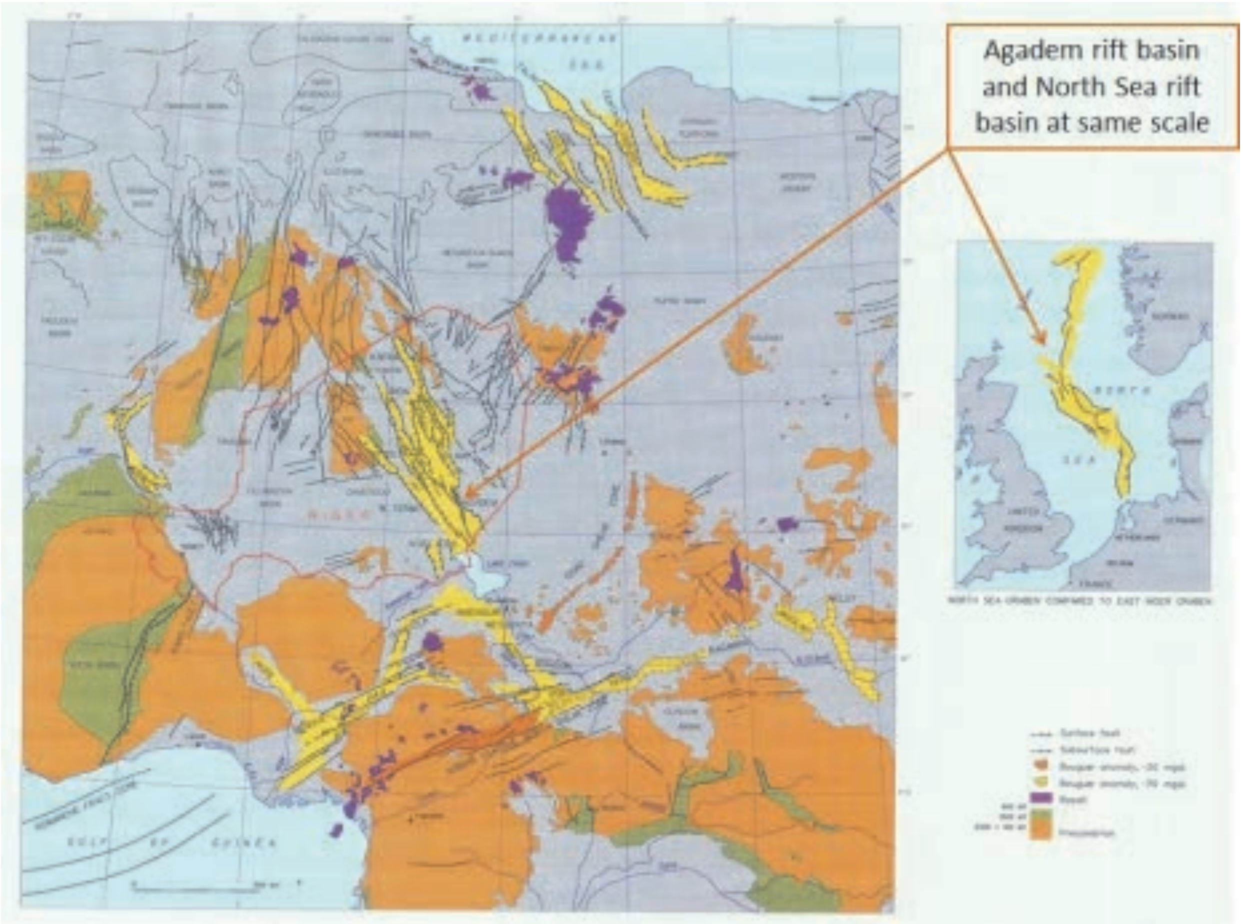

Figure 0.3 Map comparing magnitudes of the basins of Niger and the North Sea

Source: Niger Ministry of Energy & Petroleum, and in-house Robertson studies

This assessment is based on information provided by Savannah, by the Niger Ministry of Energy and Petroleum to Savannah, and on information in previous CGG in-house studies of African rift systems.

Savannah Petroleum Niger R1/R2 S.A. is the operator of the R1/R2 and R3/R4 Licence Areas with a 100% ownership in the licences. Savannah has a 95% interest in Savannah Petroleum Niger R1/R2 S.A.

The basin shows classic rift geometries (Figure 0.4) and in the Savannah Licences contains multiple stacked hydrocarbon plays (Figure 0.5).

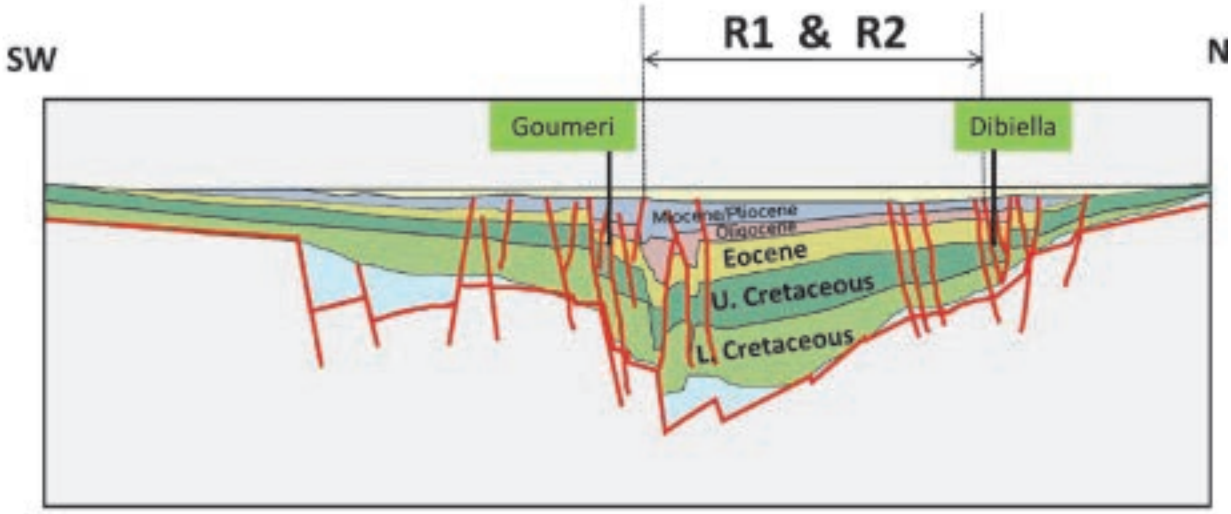

Figure 0.4 Schematic South-West to North-East Cross-Section through the Agadem Rift Basin, Niger

(Source: Niger Ministry of Energy & Petroleum and Savannah)

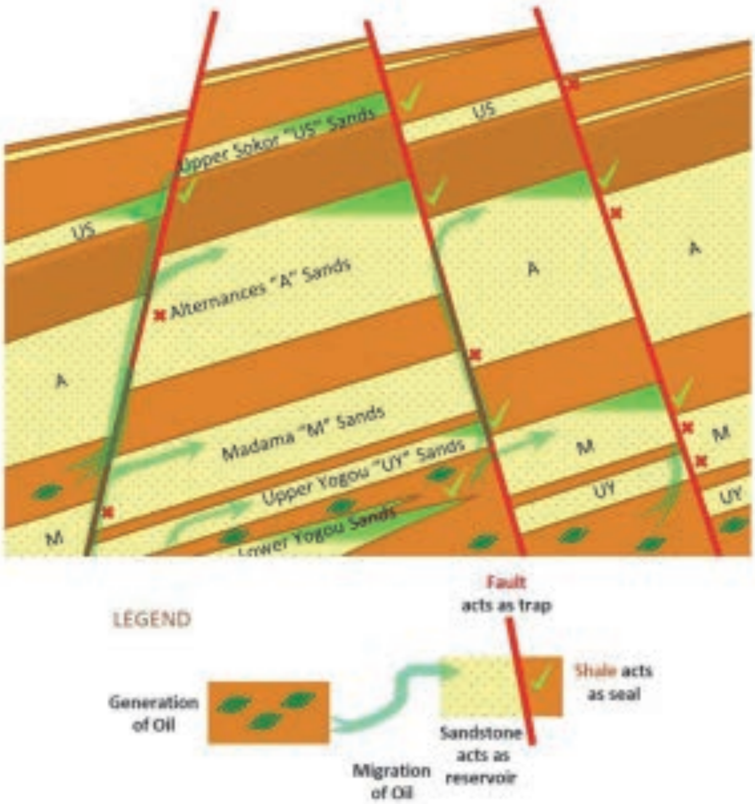

Figure 0.5 Schematic South-West to North-East cartoon cross-section to illustrate the main trapping and charging mechanisms in the Agadem Rift Basin (source: Savannah)

1.2 Sources of Information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah's technical team as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR included:

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Historical production and pressure data

In conducting their evaluation, CGG has relied upon the accuracy and completeness of information supplied by Savannah.

As the assets in question are in the exploration phase, no site visit has been conducted by CGG.

1.3 Principal Contributors

CGG employees and consultants involved technically in the drafting of this CPR have between 5 and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Andrew Webb

Mr Andrew Webb has supervised the preparation of this CPR. Andrew is the Manager of the Petroleum Reservoir & Economics Group at CGG. Andrew joined the company as Economics Manager in 2006. He graduated with a degree in Chemical Engineering and now has over 29 years' experience in the upstream oil and gas industry. He has worked predominantly for US independent companies, being involved with projects in Europe and North Africa. He has extensive experience in evaluating acquisitions and disposals of asset packages across the world. He has also been responsible for the booking and audit of reserves both in oil and gas companies, but also as an external auditor. He is a member of the Society of Petroleum Engineers and an associate of the Institute of Chemical Engineers.

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1.4 Evaluation methodology

CGG has estimated resource volumes for nine indicative prospects and leads selected by Savannah from its exploration portfolio. These prospects and leads are currently under consideration as potential drilling candidates in Savannah's initial exploration drilling campaigns. CGG has also provided estimates of the yet-to-find resources in the licences. In addition, CGG has calculated expected recovery factors, and run indicative economics for a generic development outlined by Savannah.

In estimating the resource volumes for the prospects and leads, CGG has used the standard techniques of geological estimation to develop the technical sections of this CPR. Resource ranges (low, mid and high cases) have been determined using probabilistic methods.

Savannah demonstrated and reviewed the seismic workstation interpretations during a CGG visit to their premises in June 2017. At the same time, maps and geological issues were discussed face to face with Savannah's senior technical staff. The seismic picks, reservoir structure and gross rock volume, according to these interpretations, were demonstrated to CGG. Estimates of reservoir properties have been checked by CGG, and these are thought to be reasonable or slightly conservative.

The petroleum resources definitions used in the CPR are those published by the Society of Petroleum Engineers (SPE) and World Petroleum Congress (WPC) in 1998, supplemented by the Petroleum Resource Management System guidelines (PRMS), published by the SPE in 2007.

2 RESOURCE DESCRIPTION

2.1 Tectonostratigraphy

Onset of rifting commenced in the Lower Cretaceous and subsidence continued into the Late Cretaceous. The basin was subjected to a tectonic event in the Santonian-Campanian that caused rift flank uplift and folding of the sediments in the basin floor. Subsidence subsequently continued steadily into the Cenozoic. A second major phase of rift faulting occurred in the Oligo-Miocene, before the basin returned to slow subsidence through the Plio-Pleistocene.

The sedimentary fill of this rift basin contains interbedded packages of sandstone and shale in total more than 5km thick across much of the area. The depositional setting is predominantly fluvial and lacustrine, with marine incursions occurring during the Late Cretaceous. Shales units are often organic-rich, containing both algal and terrestrial kerogen. Shales at Cretaceous level have entered the oil window across much of the basin. The latest phase of rifting was in the northern part of the basin accompanied by minor igneous centres, but these centres were too small to have a major influence on thermal maturity of the basin.

The basin received substantial clastic fluvial input, so sedimentation kept pace with subsidence for prolonged periods. This ensured that sand-rich sequences were repeatedly deposited across much of the area. Seismic interpretation suggests that there was a period in the Late Cretaceous when subsidence outpaced sedimentation and that this was accompanied by uplift of the margins of the basin. Erosion of the basin flanks provided a potential additional source of sand that could be emplaced by gravitational flow into the deeper water settings.

Consequently, the basin offers source and reservoir potential in multiple stratigraphic intervals, including at levels that to date have received few well penetrations. The fault blocks created by late Cenozoic faulting formed the traps targeted by almost all exploration drilling to date, whereas the structures formed by Santonian-Campanian tectonics are essentially unexplored.

2.2 Depositional models

It is important that the correct depositional model is applied, since this affects the way in which potential resources in undrilled acreage and the appropriate recovery factors, are estimated.

The Agadem Rift Basin contains a sedimentary fill of more than 5km and forms part of the Central African Rift System. However, it is apparent from the seismic and well data that, in the License Areas, classical rift basin depositional models, involving deep lake basins, prograding deltas and alluvial fans along fault scarps, do not apply. The reflector packages at seismic scale are remarkably layer-cake, with minimal evidence of prograding or shingled features. Inter-well correlation of wireline packages tens to hundreds of metres thick is relatively straight-forward over distances of tens of kilometres. Sands at E3 level in the NW part of the basin, which are normally too thin to be considered in volumetric estimates, often contain oil. Since these sands are far above the oil window, the oil indicates that the thin sands have substantial lateral continuity in order to connect to the faults which provide the vertical migration conduits. The depositional models need also to address the paucity of peats, coals, evaporites and conglomerates through most of the section.

Savannah's new biostratigraphic data suggests that throughout the Cenozoic and Cretaceous, deposition occurred in a relatively arid climatic regime, but with substantial influxes of fresh water. In the context of local aridity, this implies input from major rivers. This input persisted irrespective of whether the depositional setting in the basin was entirely terrestrial or was subjected to marine flooding. These conditions are compatible with CGG's in-house palaeogeographic and palaeoclimatic modelling for the area.

The layer cake depositional geometries are interpreted by CGG as resulting from sedimentation keeping pace with subsidence because of high influxes of fluvial clastic sediment. The high fluxes of clastic sediment appear not to be due to rapid erosion of local highs, since extraclast conglomerates are largely absent. The amount of core data available is limited, but suggests that the sandstone sequences are fine to medium grained, with quartzose pebbles (less than 10mm in diameter) occurring only occasionally in the Madama Formation. Our overall interpretation is therefore of rivers with relatively large discharges draining wet climatic areas, traversing a low relief landscape and depositing their sediment in a shallow basin in an arid setting.

2.3 Petroleum geology of stratigraphic units

2.3.1 Upper Sokor Formation

Savannah currently carries oil volumes at this level in nine of the prospects and leads reviewed. This represents a potentially important new play in the basin, and so has warranted particular scrutiny. This new play is supported by seismic, hydrocarbon shows and well testing.

The phase of rift faulting that created most of the structural traps in the proven Sokor Alternances and Yogou plays post-dated deposition of the Upper Sokor and so also created structural traps at Upper Sokor level.

Many of the Eocene exploration wells were drilled vertically to target footwall closures at the Sokor Alternances, and so either penetrated the Upper Sokor in hanging-wall sections, or failed to fully penetrate the Upper Sokor sequence, owing to the magnitude of heave on the bounding fault. Consequently, the Upper Sokor is under-represented in the existing well data sets, so estimation of resource potential at this level cannot be determined directly from the existing exploration statistics. The geological context of this potential play was therefore examined in order to provide a basis for resource estimation and geological risking.

Hydrocarbon charge: Basin modelling undertaken by Savannah indicates that source rocks at Cretaceous levels would have been oil mature at the time of Oligo-Miocene rifting, so the rift faulting could have provided charge pathways into the Upper Sokor. Subsequent burial by late syn-rift fill and during post-rift basinal subsidence, might have resulted in additional maturation at Cretaceous levels, potentially resulting in further charge to the stacked plays.

In order to reach the Upper Sokor play, hydrocarbons have to penetrate the Low Velocity Shale (LVS). This shale is present throughout the basin, and is typically about 100m thick, so is potentially a barrier to vertical migration. However, oil has been recovered from the Upper Sokor level in at least six wells, and shows have been reported at this level in at least another 12 wells. Most shows at this level are in areas remote from igneous features, so contact metamorphic maturation of shales above the LVS is not considered by CGG to be the explanation for the majority of shows in the Upper Sokor, Consequently, it is concluded that rift faults have provided migration pathways through the LVS in some areas.

It is not clear whether these shows occur exclusively up-dip from faults with throws greater than 100m, which would juxtapose Sokor Alternances sands against Upper Sokor sands, or whether temporary dilation on fault planes by tectonic movement and/or hydrocarbon fluid pressure provided migration paths directly through the Low Velocity Shale.

Biodegradation: Ordinarily bitumen formation through biodegradation might be considered an important risk in hydrocarbon basins at depths of less than 1,600m. The Upper Sokor is the shallowest play identified to date in the Basin, with most prospects and leads identified to date occurring at depths of less than 1600m, compared with depths of about 1600m to 3500m for the other plays.

CGG has not encountered accounts of significant bitumen deposits in this basin, so biodegradation is not considered to be a major issue. Nonetheless, some evidence of biodegradation, as interpreted from gas chromatograms, does occur in 15 of the oils examined by IGI (2015). The 15 biodegraded oils range in API gravity from about 17° to 30°.

The available evidence, which is limited, suggests that the oils found in the Sokor Alternances and Yogou formations come from a mixture of marine and lacustrine sources. Wax is present in some oils, but does not appear to be a dominant feature of the hydrocarbons reported to date.

The relationship between biodegradation, API and viscosity is not straight-forward, particularly in the case of the wax component of crudes. Biodegradation may contribute to decreased API gravity, but the negative impact of a slight API decrease can be offset by lowered pour points and less wax deposition in pipework and processing facilities (Wenger *et al.*, 2002).

To conclude, there is no available evidence that oils at Upper Sokor level have been damaged by biodegradation, but also the number of penetrations that could potentially have penetrated oil accumulations at Upper Sokor level is very limited, so this remains an area of uncertainty at the shallowest levels.

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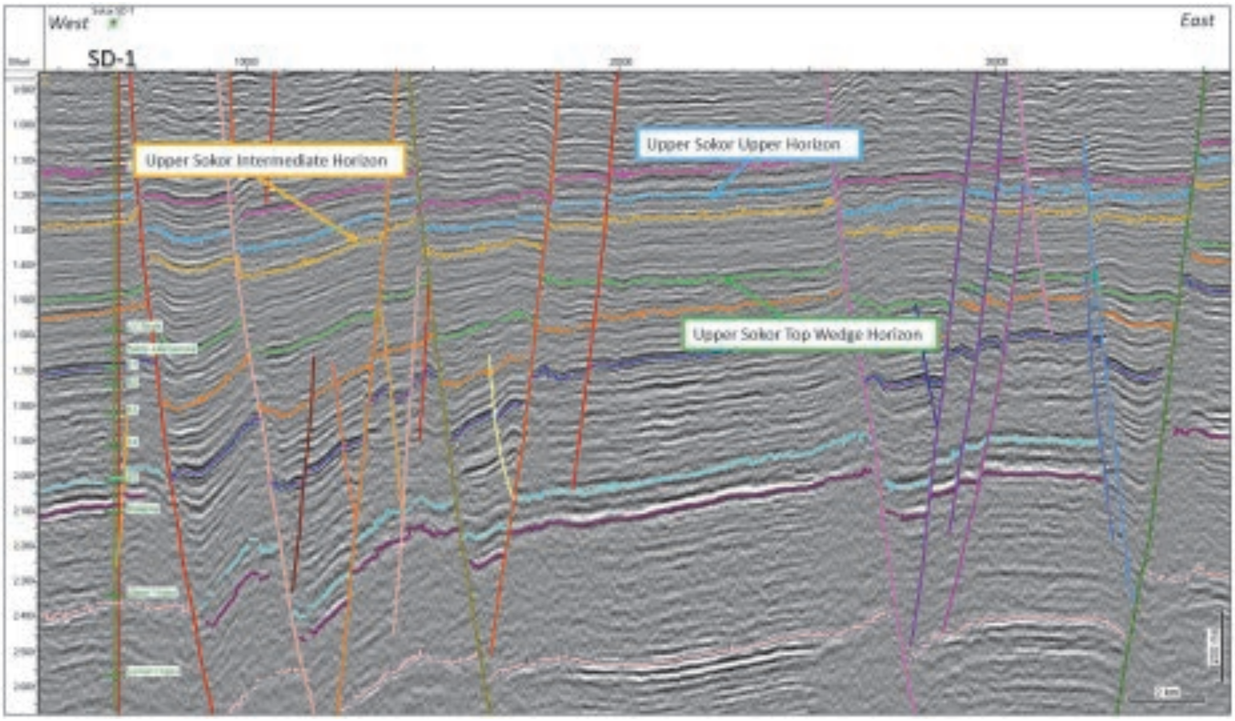

Figure 2.1 W-E 3D seismic profile through Sokor SD-1 well, , in the R3 East 3D. The Upper Sokor contains variable amplitudes within a subtle sedimentary wedge above the LV Shale (green to orange markers).

Depositional model: The wells show that the Upper Sokor comprises reservoir-seal couplets similar to those in the Sokor Alternances. Seismic review suggests these sand-shale sequences in the lower part of the Upper Sokor show a mixture of layer cake and gentle wedge geometries. The wedges thicken towards some faults. Most of the displacement on these faults was much later, but it appears that a brief phase of minor movement occurred on some faults during deposition of the lower part of the Upper Sokor. These features are illustrated in Figure 2.1.

Modern Lake Chad provides a potentially useful analogue for the depositional model envisaged for the Upper Sokor. The gross tectonostratigraphy of modern Lake Chad is similar in that the clastic inputs to the area have evidently been sufficient to infill all the accommodation space created in the Niger to Chad sectors of the basin during late Cenozoic rifting.

The hydrological budget of the Lake Chad is nearly balanced, with most of its water inflowing from the south. Inflow is via groundwater throughout the year, and is supplemented by major flow in rivers during the southern wet season. The subdued geometry of the lake basin ensures that the lake shows large fluctuations in area in response to modest changes in lake level, and this occurs on time-scales of tens to thousands of years. The result is that lake-margin swamps are largely ephemeral and the organic matter is rapidly oxidised when the lake recedes, so no peat accumulates over most of the basin. The groundwater-fed swamps on the southern margin are potential exceptions that may allow some peat accumulation.

The advance and retreat of the shorelines results in laterally persistent sheets of sand. In addition, the lake flats exposed during low stands become areas of sand deposition, with reworking by ephemeral run-off and by wind. The result can be sand systems that show excellent sorting and lateral continuity, though individual beds of sand may be no more than a few metres thick.

These patterns resemble features revealed by horizon slice amplitude extraction in the lower part of the Upper Sokor. The extractions on sandy intervals could be interpreted as representing a coalescence of sandy facies including broad curving beach ridges, irregular fluvial sand sheets, and sand reworked by wind or waves. The extractions on more mud-rich horizons suggest a more homogeneous distribution of facies which in this context might include mud-dominated lacustrine-alluvial deposits, with the higher amplitudes including peat deposits preserved preferentially on the subsiding side of faults.

There is no obvious difference in reflector character between the Upper Sokor and the underlying Sokor Alternances in seismic sections. These interpretations therefore also support the relatively layer-cake depositional model adopted here for the Sokor Alternances, with correspondingly beneficial implications for hydrocarbon production.

2.3.2 Sokor Alternances Formation

Savannah currently carries oil volumes at this level in all of the prospects and leads reviewed.

This play has been extensively drilled within the retained acreage of the Agadem Rift Basin, and the discovery data mostly reflect the success of this play.

The oil at Eocene level represents leakage from Cretaceous levels, predominantly up faults and across faults where sands are juxtaposed. The faults were mostly active in the late Oligocene, and modest subsidence, not accompanied by major faulting, has continued since.

The Sokor Alternances contain many more reservoir/top seal couplets than the Upper Yogou. Only a small proportion of the Sokor Alternances Eocene sands contain oil – probably because of trap leakage across faults in these relatively sandy sequences. It is unusual to find more than four or five charged reservoirs in the Eocene fields.

2.3.3 Madama Formation

Savannah does not currently carry any oil volumes at this level in the prospects and leads reviewed.

The Madama Formation is present in all wells drilled to that depth across the basin. This formation has a distinctive seismic character that could be traced across the basin on all seismic reviewed.

In many fault blocks, the Madama Formation may carry attic oil trapped against shales in the Lower Sokor Alternances. CGG thus views the Madama Formation as a potential subject of prospective resource volume upside.

2.3.4 Yogou Formation

Savannah currently carries oil volumes at this level in five of the prospects and leads reviewed.

Basin modelling, and the distribution of discoveries across the Agadem Rift Basin, demonstrates that the majority of the oil in the Eocene accumulations was generated from Cretaceous source rocks, at Yogou or deeper levels. The Yogou reservoirs effectively sit within the oil window, with very short migration paths from kitchen to trap. The Yogou reached maximum maturity during the subsidence which post-dated Oligo-Miocene faulting, and today the Yogou sequence remains in the oil window across much of the basin. It is therefore inferred that whilst some traps at Yogou level may temporarily have been breached during faulting, charge of Yogou traps will have continued through to the present day.

In the Dinga Slope and Dinga Ridge areas, a number of large structures, that are visible on 2D seismic at Yogou level, do not exist at shallower Eocene levels. These large structures show relatively few Cenozoic faults.

Review of 2D and 3D seismic across the basin suggests that the Yogou Formation was deposited during the sag phase that post-dated Cretaceous rifting. CGG interprets the relationships exhibited on seismic and the new biostratigraphic data obtained by Savannah from cores at Upper Yogou level, as indicating that deposition of Upper Yogou sands (and ultimately Madama sands), was triggered by tectonic movements during the Santonian to early Maastrichtian. This correlates with a regional tectonic event that affected several Cretaceous rift basins along the Central African Rift System.

Review of the available porosity-depth data suggests that the Yogou sands lie on a trend that is 2-3% higher than that of the Eocene section. This might be a function of overpressure, or initially better quality reservoir facies.

Review of the available log profiles suggests that multiple reservoir-seal couplets are present in the Yogou, and as long as there are on average four or more of these, then the numbers of separate accumulations at Yogou and Eocene Sokor Alternances levels can be expected to be similar.

At Yogou level, shale seals will be more compacted, and consequently more effective than at Eocene level, where shale seals are proven by numerous accumulations. In addition, review of the 3D seismic data shows that faults at Eocene levels tend to merge into a smaller number of faults at greater depth. This means that the risk of trap breaching by faults is reduced at Yogou level. This in turn means that traps are more likely to be filled to spill at Yogou levels than within the Eocene and Miocene sections.

There will be several Yogou structures where fault seal risk is high because the sand-rich Madama Formation is on the downthrown side of the fault trap. However, in contrast to the situation in the Eocene, where the distribution of cross-fault leakage into sands is hard to predict, such structures at base Madama level should be readily imaged on 3D seismic, and thus should be avoidable for drilling.

The reduction in numbers of faults with depth suggests that the size of individual fault block traps will be greater at Yogou than at Eocene levels.

Recently, testing of the Upper Cretaceous Yogou reservoirs has proven productive, giving similar, or better, flow rates than in the Eocene section. The good reservoir performance appears to result from a combination of reasonable retained porosities and lower viscosity oils than in the Eocene section.

2.3.5 Lower Yogou and Donga Formation

Cretaceous folding and Cenozoic faulting together form an additional set of trapping geometries beneath Savannah's acreage at Lower Yogou and Donga levels. Figure 2.2 illustrates these features. In some parts of Savannah's acreage these intervals are found at depths that are relatively easily drillable.

The depositional setting implied by biostratigraphic data, limited geochemical analyses, and the widespread occurrence of gas shows far outside the footprint of the main gas window at Yogou level suggests that a mature source rock is present at Donga or deeper levels.

Thin sandstones occur at Donga and older stratigraphic units in wells around the basin edges, and nothing is known about sand distributions beneath the basin axis, but the amplitude variations at these depths suggest that multiple lithologies, potentially including reservoir facies, may be present.

The Donga interval is modelled as being within the gas window in the deepest parts of the basin, so any oil source rocks present will have charged reservoirs in this and overlying intervals before oil expulsion started from the Yogou source rocks. It is not presently clear what proportion of reservoirs in this interval will now be gas charged rather than containing oil.

Savannah has only recently evaluated the play potential in this stratigraphic interval, following on from its detailed investigations of the Upper Yogou prospectivity. For this reason, Savannah has not yet interpreted the interval to the level where prospects and leads can be added to its proprietary exploration portfolio. The play is, however, included in this yet-to-find analysis included in this CPR (section 3.2).

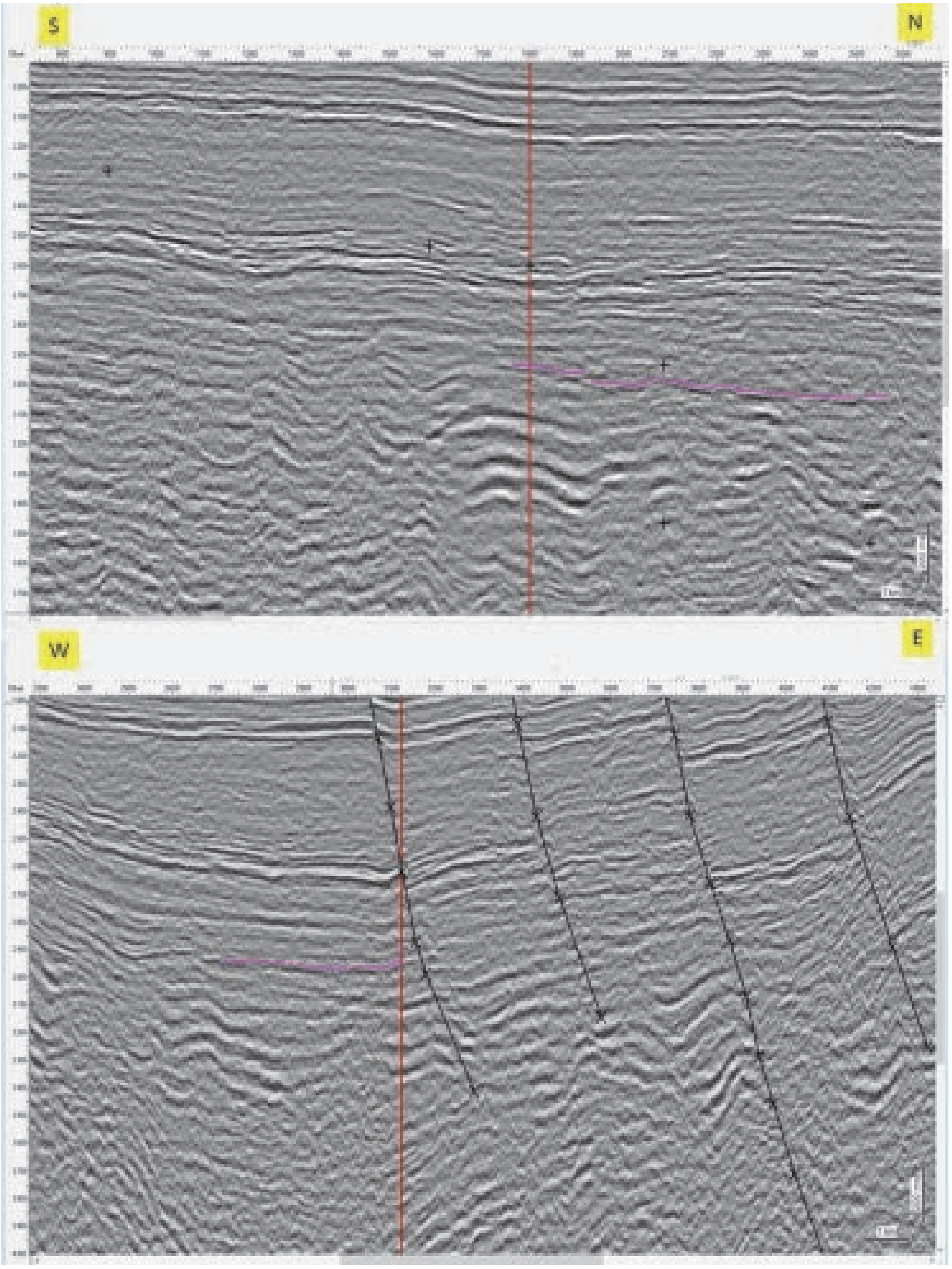

Figure 2.2 Structures at Donga level beneath R4

References

Wenger, L. M., Davis, C.L. and Isaksen, G.H., 2002. Multiple Controls on Petroleum Biodegradation and Impact on Oil Quality. SPE Reservoir Evaluation & Engineering, October, p. 375-383.

2.4 Prospects and leads

The high discovery rate in the Agadem Rift Basin demonstrates the richness of the basin. The discoveries follow two trends of rift-related tilted fault blocks on either side of the main rift and merge into one zone at the southern end. The central part of the main rift, across the R2 licence area, has less faulting of Oligocene-Miocene age, and has not been as extensively explored. This area could contain more subtle larger traps. The main risk is fault seal where sand is against sand at the faults. The results of the wells show that within the Eocene Sokor Alternances there is sufficient shale in the section to result in there being a high chance that there will be sand against shale in at least one of the sands. Variations in fault throw could result in restricting trap size on any given sand interval, but this could result in increasing the area of seal in one of the other sands. In the R3 area there are five Sokor Alternances sand intervals (E1 through E5) thus maximising the chance of success. R3 East lies within the western fault and discovery trend, as can be seen in Figure 2.4. In the R1 area to the north the E3 interval is shalier, and is not regarded as a target. However, there are still four Sokor Alternances objectives. The R3 Central area only has 2D coverage and thus the Sokor Alternances Formation has to be treated as a single unit, for the purposes of volumetric calculation, as the individual sand intervals cannot be seismically defined.

As noted in section 2.3.1, the overlying Upper Sokor sands are usually offset from the crest of the Sokor Alternances, by virtue of the configuration of the fault block. As most exploration wells in the basin have been vertical, and have targeted crests at the Sokor Alternances, closures at the Upper Sokor level have been frequently been missed by the drill bit. Closures at the Upper Sokor are thus valid exploration targets, and these traps have a better chance of sealing faults. Savannah aims to design its exploration wells in such a way to evaluate multiple targets at both stratigraphic levels in a single well bore.
The older parts of the Cretaceous Yogou Formation have not been widely targeted by earlier operators and thus this represents a target in areas where it is shallow enough.

There have been numerous seismic programs in the area, comprising 2D of various vintages and modern 3D, as shown in Figure 2.4. The 3D surveys relevant to this review of prospects are the R3 East 3D and the Dinga 3D, as outlined in red in Figure 2.4Figure 2.3. The prospects and leads reviewed are shown in Figure 2.5.

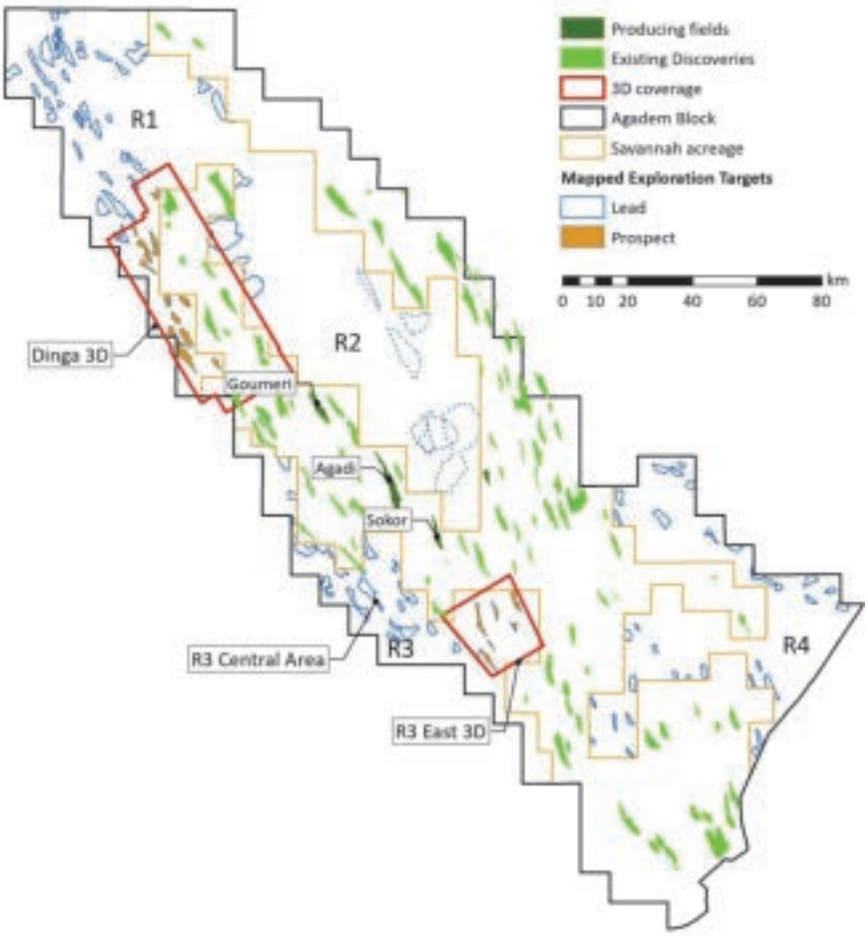

Figure 2.3 Showing the Savannah portfolio with discovered fields and relevant 3D surveys

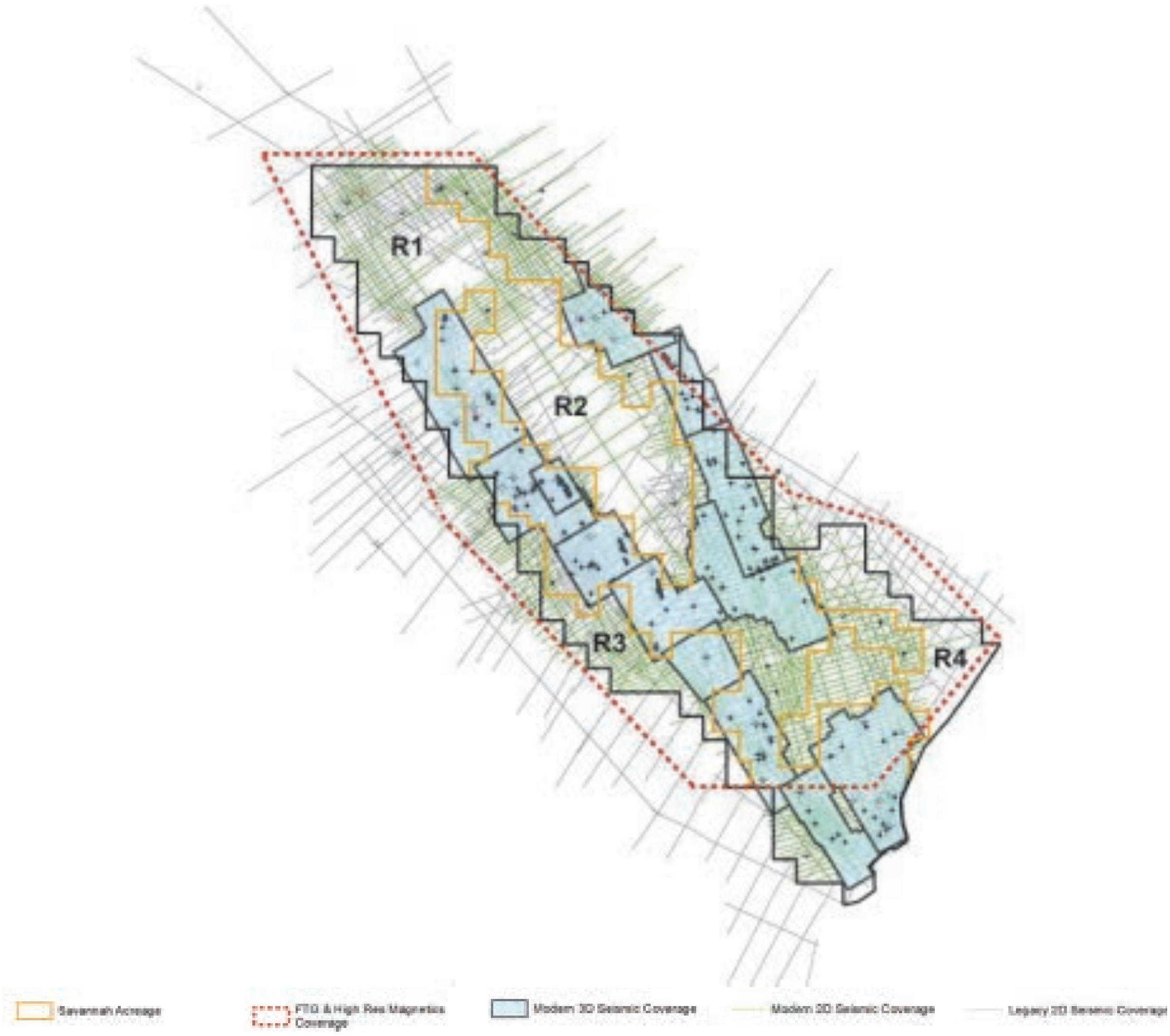

Figure 2.4 Seismic coverage in the Agadem Rift Basin

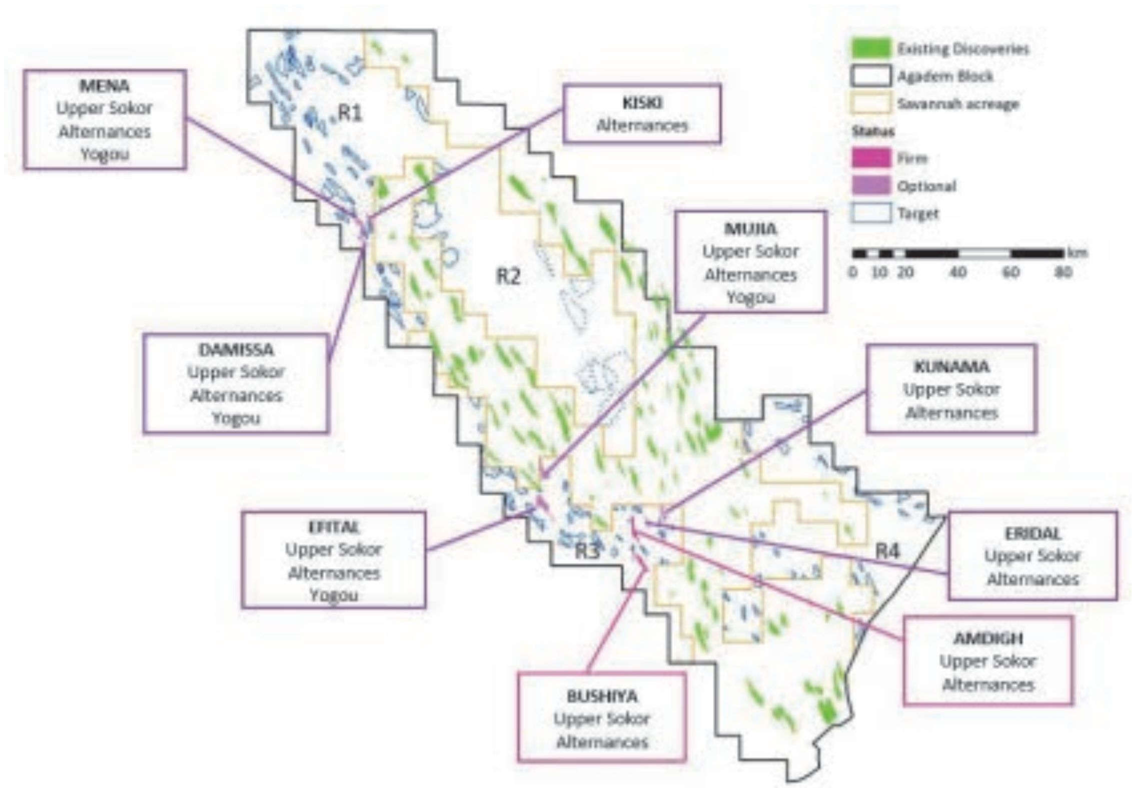

Figure 2.5 Map showing indicative drilling Targets assessed by CGG (Source Savannah)

2.4.1 R3 East prospects

The prospects in the R3 East area are covered by the R3 East 3D survey. This survey is considered to be of good quality. The pick for the Sokor Alternances E1 sand is a strong trough due to the increase in velocity. The Madama is not a consistent event due to interference with the E5 sands. The overlying LVS is generally a strong peak. The Upper Sokor varies across the region. The well Ourami-1 was drilled within the area of this 3D. This well was drilled on 2D data and the New 3D data shows it to be located a good way downdip from the crest (ie off structure). All the prospects identified in the area are clearly within the oil discovery trend with discoveries to the northwest and to the southeast.

2.4.1.1 The Bushiya Prospect

The Bushiya Prospect is situated in the southwest part of the R3 East 3D survey and is a tilted fault block, similar to the Sokor Field, as can be seen in Figure 2.6 and Figure 2.7.

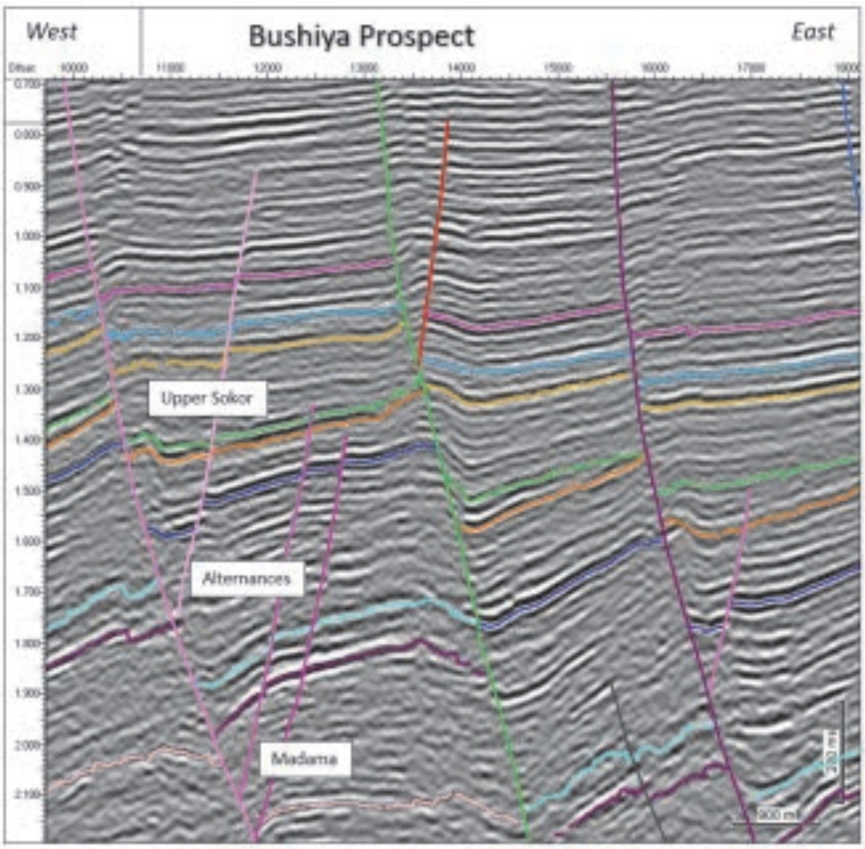

Figure 2.6 R3 West-East 3D seismic line across the Bushiya Prospect

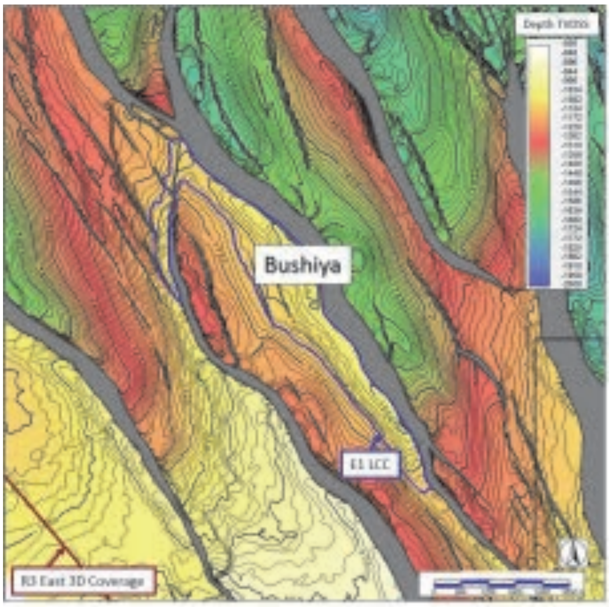

Figure 2.7 Sokor Alternances E1 Depth Map (m) over the Bushiya Prospect showing the Lowest Closing Contour (LCC)

The seismic section through Bushiya (Figure 2.8) shows a pronounced fault forming the trap. The throw on the fault is probably greater than shown due to the fault shadow masking the reservoir contact with the fault and suggesting a rollover into the fault which may not exist. Figure 2.7 is a depth map on the top of the Sokor Alternances reservoir E1. The blue polygon represents the outline of the closing contour at 1118m TVD. On the downthrown side of the fault, the contours can be seen to be turning into the fault, indicating the variation in throw along the fault. This throw variation could result in changing cross-fault juxtapositions from sand-against-shale to sand-against-sand, which could restrict the area of closure that seals. However, the loss of seal on one sand would provide a gain of seal on another. With 5 sands intervals within the Sokor Alternances, this would suggest that at least one sand will be sealed.

All five Sokor Alternances sands are believed to be present in this prospect, thus increasing the overall chance of success.

2.4.1.2 The Amdigh and Eridal Prospects

These prospects are tilted fault blocks as shown in seismic line in Figure 2.8. Amdigh is the fault block on the left. Both prospects are defined by clear horizons and both significant throw on their respective bounding faults. As with Bushiya, there is a fault shadow masking the crest of the prospects up against the fault. Both prospects should have the five Sokor Alternances sands as objectives, as well as the overlying Upper Sokor.

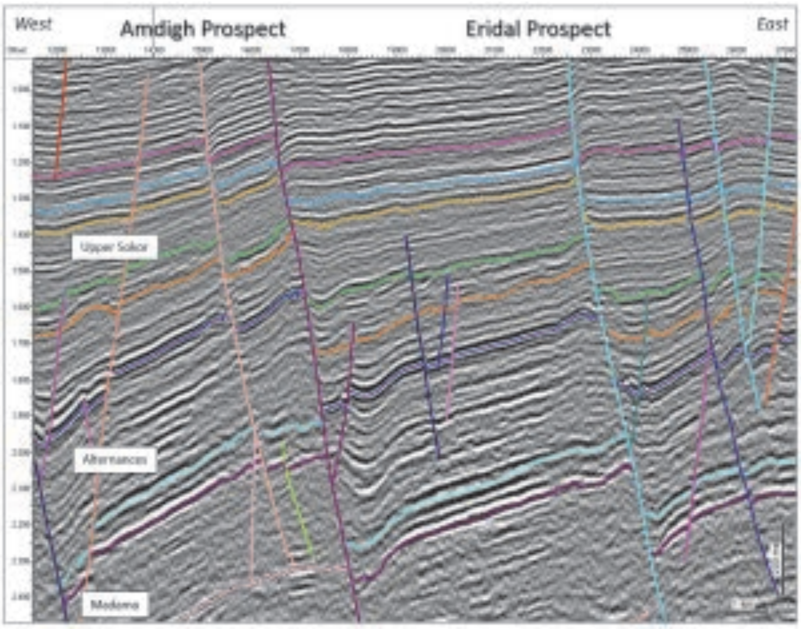

Figure 2.8 R3 West-East 3D seismic line across the Amdigh and Eridal Prospects

A depth map on the E1 horizon over the Amdigh and Eridal Prospects is shown in Figure 2.9. The Blue polygons show the lowest closing contour area for each prospect.

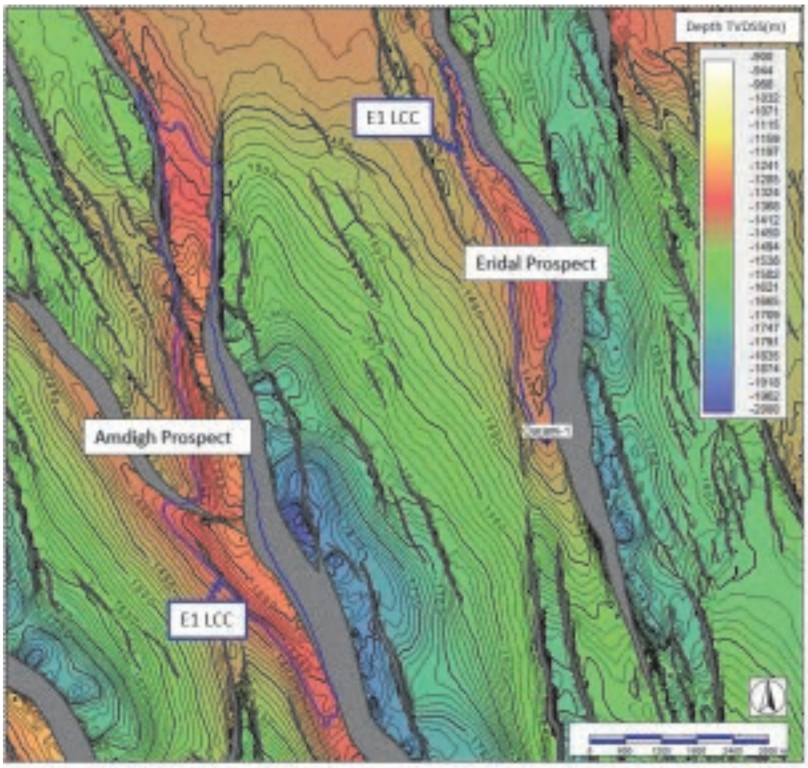

Figure 2.9 Sokor Alternances E1 Depth Map over the Amdigh and Eridal Prospects

2.4.1.3 The Kunama Prospect

The Kunama Prospect is a simple horst block, much like the Goumeri Field (Figure 2.10).

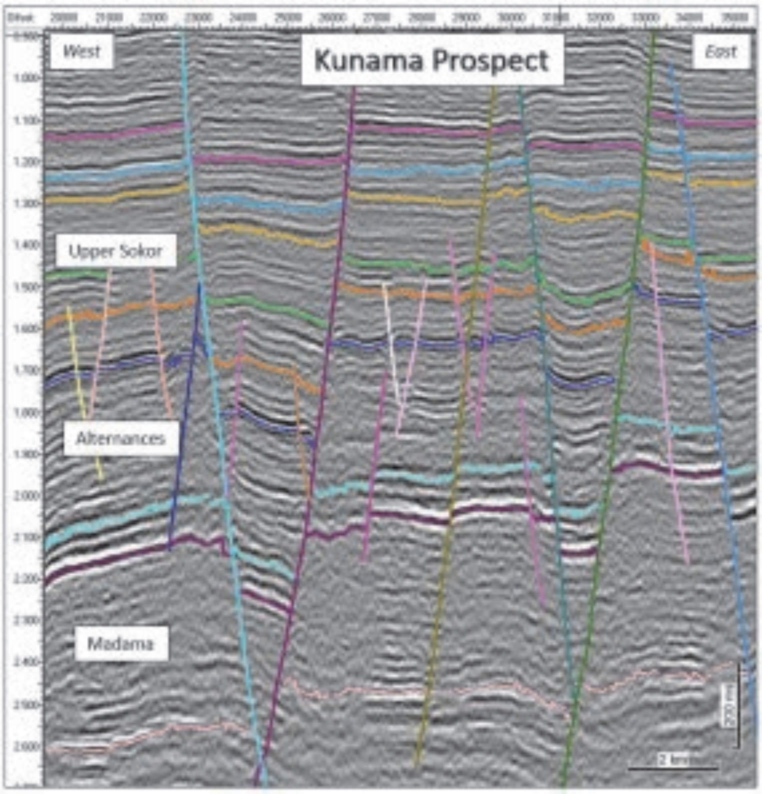

Figure 2.10 R3 West-East 3D Inline across the Kunama Prospect

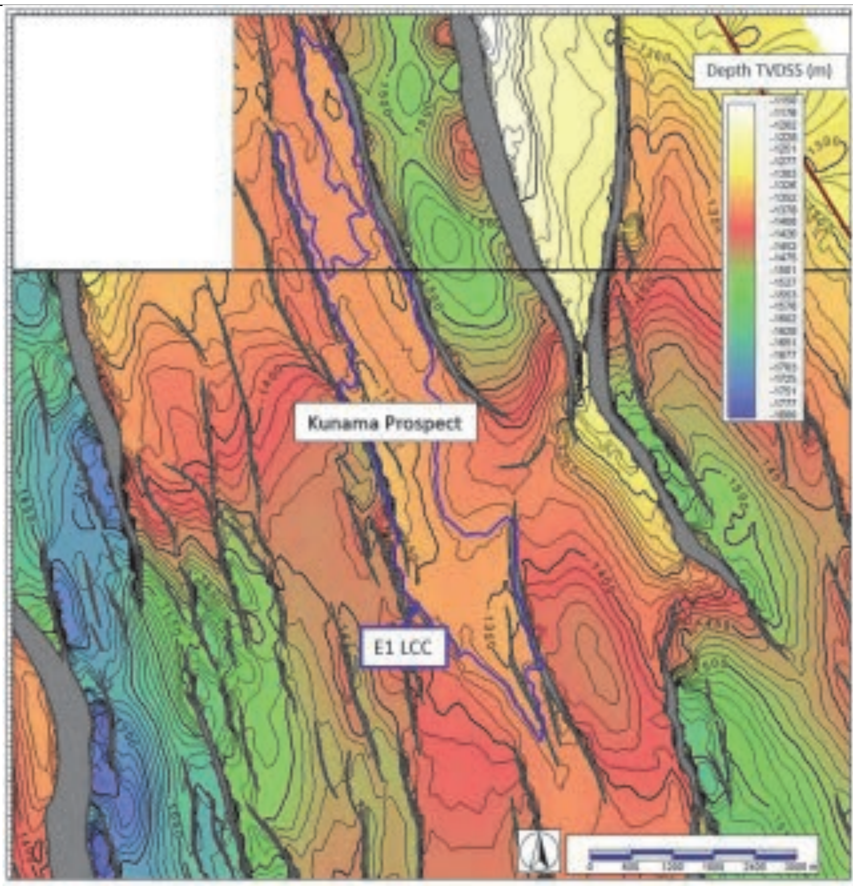

Figure 2.11 Sokor Alternances E1 Depth Map over the Kunama Prospect

The horizons shown in Figure 2.14 clearly stand out being the same as the other prospects in the R3 East area. The E1 Depth map in Figure 2.11 shows the horst block containing the Kunama Prospect.

All five of the Sokor Alternances reservoir-bearing sequences should be present in this prospect.

2.4.2 R1 prospects

The Prospects evaluated in the R1 Licence Area are covered by the Dinga 3D survey. All of the horizons can be seen in the seismic line in Figure 2.12.

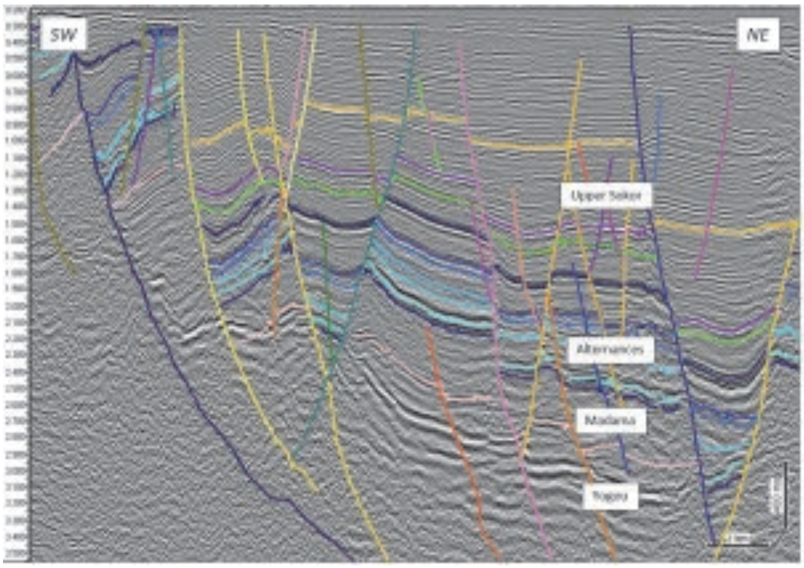

Figure 2.12 3D seismic line running SW to NE from the rift bounding fault into the basin

2.4.2.1 The Kiski Prospect

The Kiski Prospect is a tilted horst block dipping into the basin which enables a better migration pathway. There are four Sokor Alternances targets in this prospect. The Dinga 3D line shown in Figure 2.13 runs through the prospect. In Figure 2.16 the Sokor Alternances are juxtaposed against the LV shale, suggesting a low fault seal risk. A moderate fault shadow effect can be seen in the deeper events.

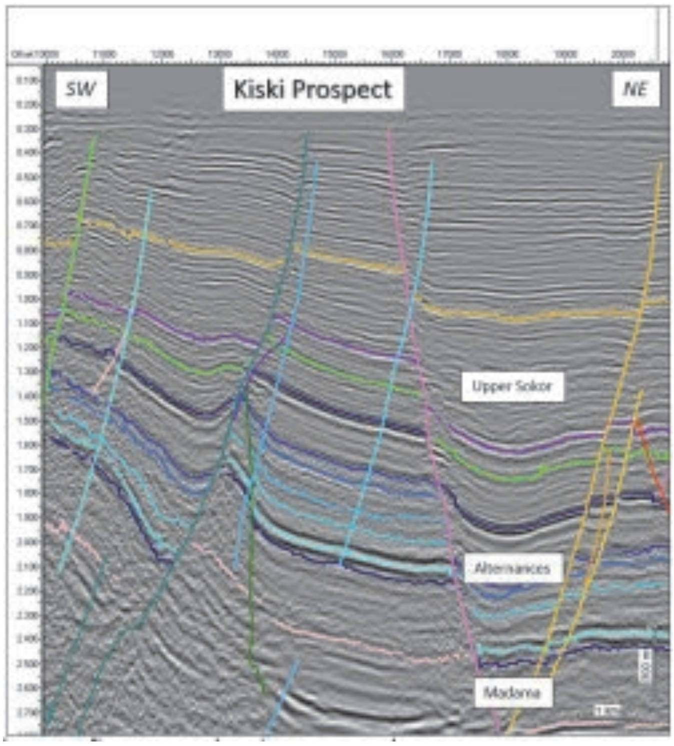

Figure 2.13 3D seismic line through the Kiski Prospect

Figure 2.14 is a depth map for the E1 horizon over the Kiski Prospect, with the blue polygon marking the closure at 1300m.

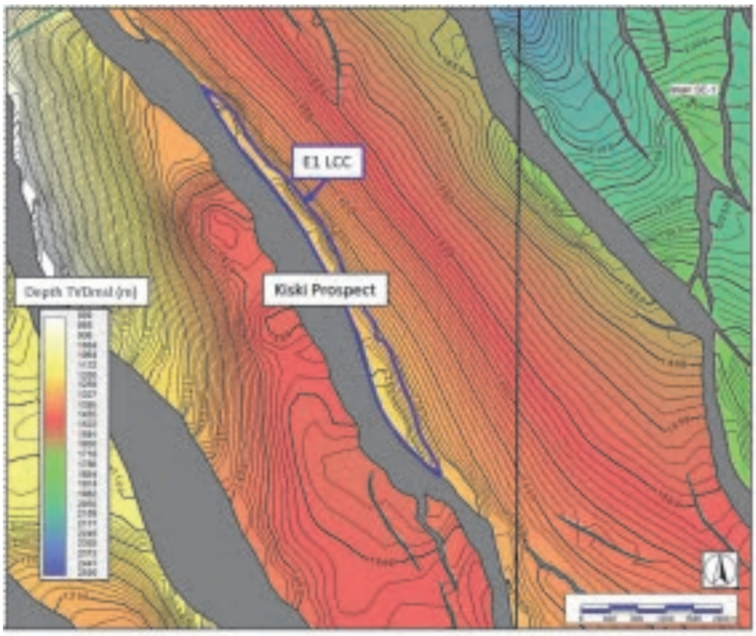

Figure 2.14 Sokor Alternances E1 Depth Map over the Kiski Prospect

2.4.2.2 The Mena Prospect

The Mena Prospect is a horst overlying a deeper ridge similar to the configuration observable at the Goumeri field. The later faulting created a graben above the horst similar to that seen over the Goumeri Field. Unfortunately, the seismic image over the prospect is not very clear due to the complications of the overlying faults. The E1 horizon is difficult to see, which may be due to shadowing by the faults. The prospect is ideally placed updip from the Imari South East (SE) oil discovery. These features can be seen on the seismic line in Figure 2.15.

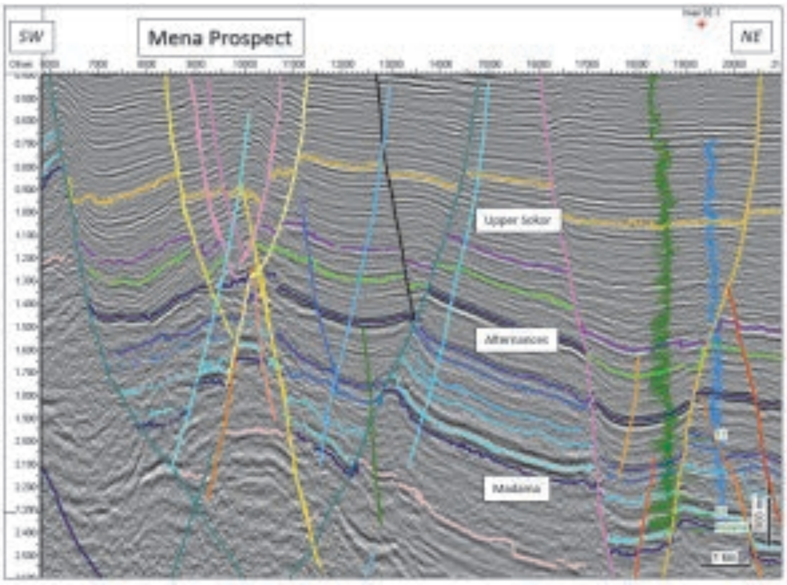

Figure 2.15 3D seismic line through the Mena Prospect and the Imari SE Oil discovery

The Mena Prospect has four Sokor Alternances objectives (E1, E2, E4 and E5). In addition, there is an Upper Sokor objective. An E1 depth map over the Mena Prospect is shown in Figure 2.16. The blue polygon in Figure 2.19 delineates the lowest closing contour.

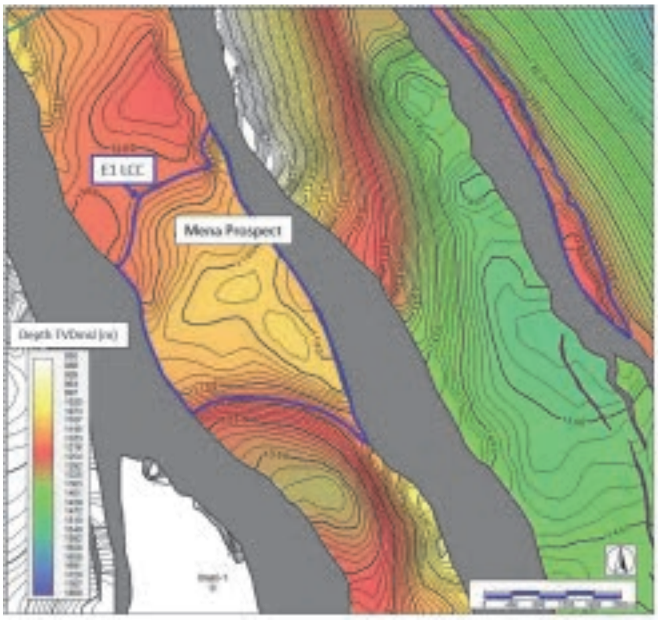

Figure 2.16 E1 Depth map over the Mena Prospect.

2.4.2.3 The Damissa Prospect

The Damissa Prospect is a tilted fault block near the edge of the main rift. The bounding fault has a large throw with the Sokor Alternances being entire thrown against the Upper Sokor. This prospect has six objectives, the five Sokor Alternances horizons, the Upper Sokor and the Cretaceous Yogou Formation. The few wells which have tested the Yogou Formation contain shows, and have delivered a number of discoveries, thus the Yogou could develop into a significant play. The seismic line, shown in Figure 2.17, runs SW-NE through the prospect and the main prospect bounding fault.

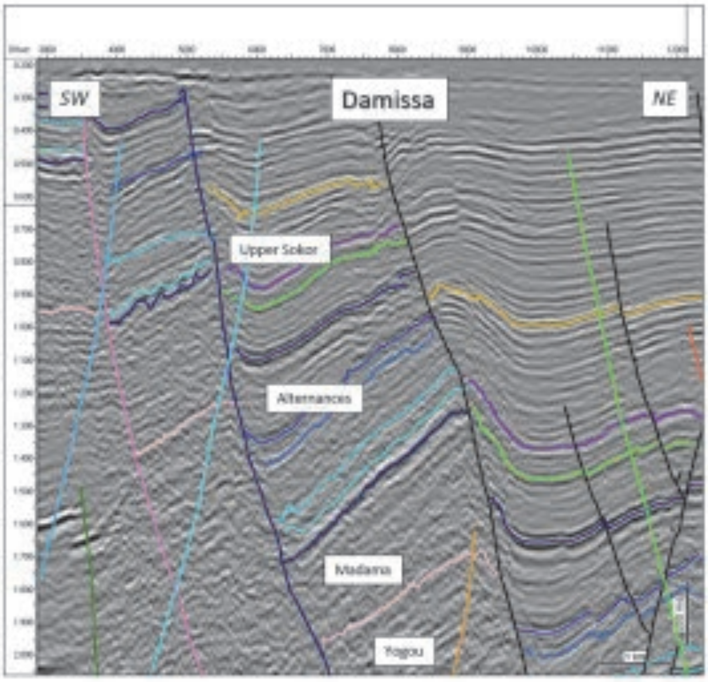

Figure 2.17 3D seismic line through the Damissa Prospect.

A depth map at E1 level over Damissa is shown in Figure 2.18. The prospect is situated at a junction of faults. The blue polygon outlines the lowest closing contour at 630m.

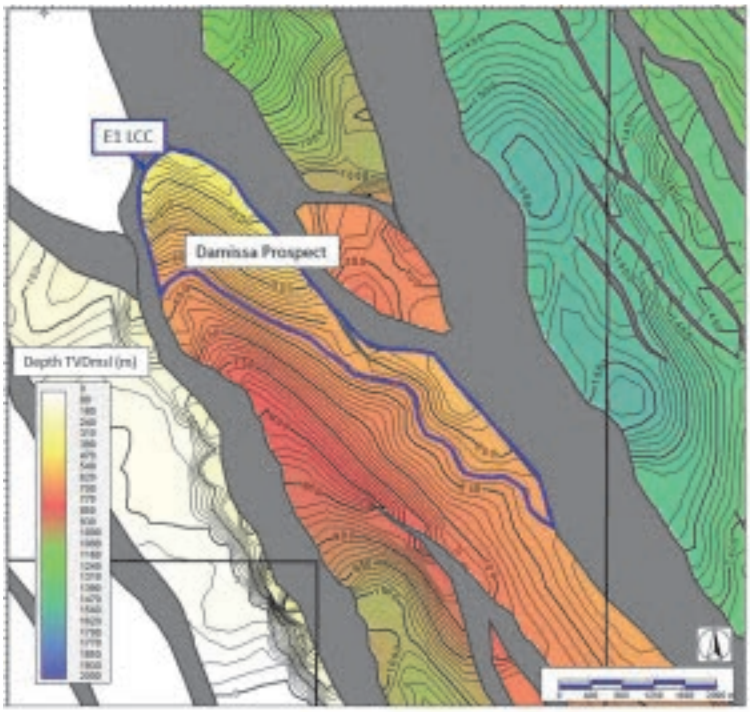

Figure 2.18 Sokor Alternances E1 depth map over the Damissa Prospect

This prospect also has a good closure at the Yogou level. However, as there are not many penetrations of the Yogou in the vicinity, the seismic tie is a bit more difficult.

2.4.3 R3 Central leads

The R3 Central area is mostly covered by 2D data, with 3D limited to the periphery. The seismic picks are limited to the Upper Sokor, the top of the Sokor Alternances and the top of the Yogou. The resource allocation is thus limited to these three horizons. One of the leads, Mujia, is also partly covered by the Agadi 3D.

2.4.3.1 The Efital Lead

Efital is a robust lead, with good 2D seismic coverage. Efital is a horst block and is shown on the seismic line in Figure 2.19. The Upper Sokor and the Sokor Alternances horizons are clearly seen over most of the structure, but the pick fades as it goes into the shadow of the red fault. The Yogou horizon (pink) is not easy to follow.

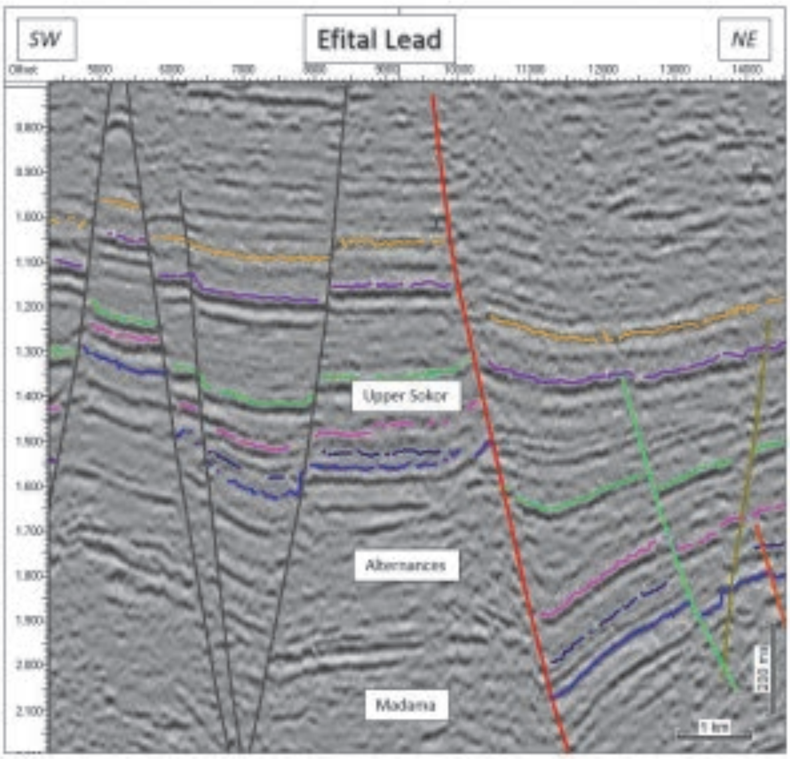

Figure 2.19 2D seismic line running SW-NE through the Efital Lead.

The Sokor Alternances depth map in Figure 2.20 shows the Efital Lead. The Sokor Alternances lowest closing contour is marked by the blue polygon and is well controlled by the seismic coverage.

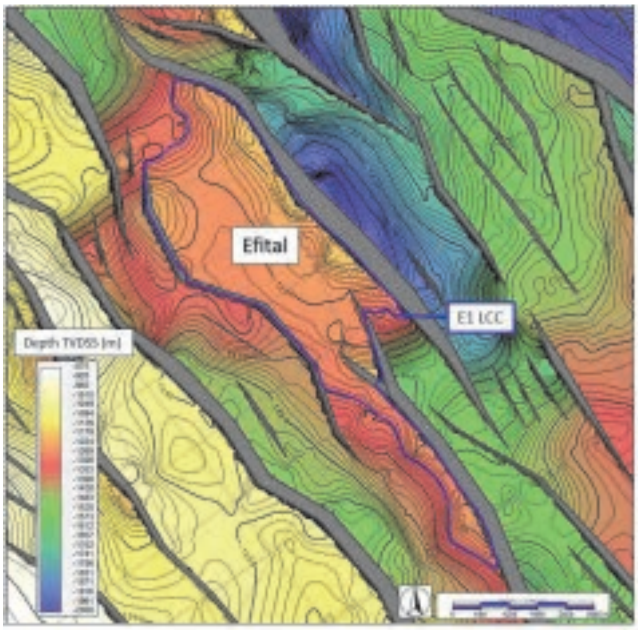

Figure 2.20 Sokor Alternances' Depth Map over the Efital Lead

2.4.3.2 The Mujia Lead

The Mujia Lead is partly defined by 3D seismic data (northern) and partly by 2D (southern). Both the Sokor Alternances and Upper Sokor closures extend into the 3D area, whilst the Yogou closure is restricted to the 2D area. The lead is on a tilted horst which dips into the basin, to the south. Both the Sokor Alternances and Upper Sokor closures lie on the western side of the horst. The southern part of the lead extends into a narrow horst. Figure 2.21 shows a 3D seismic line across the Mujia Lead and Figure 2.22 shows a Sokor Alternances E1 depth map. The central blue polygon defines the lowest closing contour. The red outline shows the extent of the Agadi 3D survey.

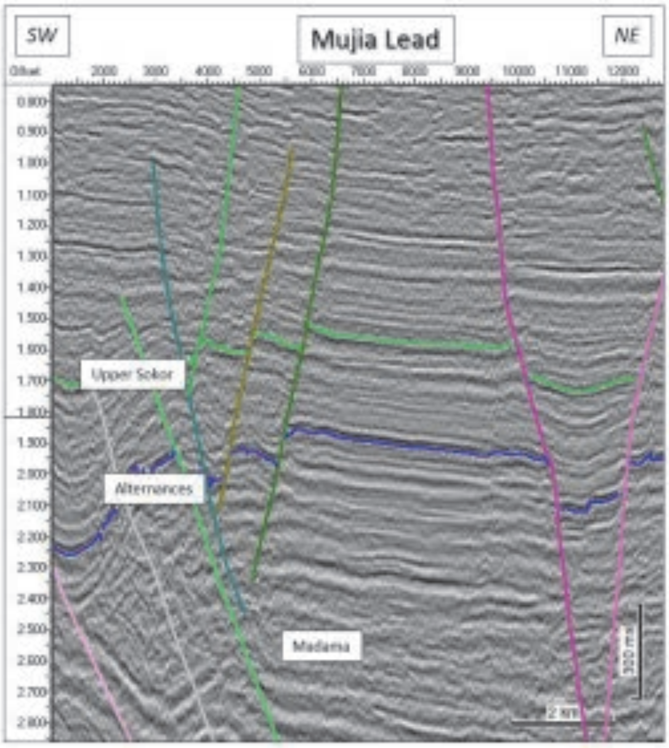

Figure 2.21 3D seismic line from the Agadi survey across the Mujia Lead

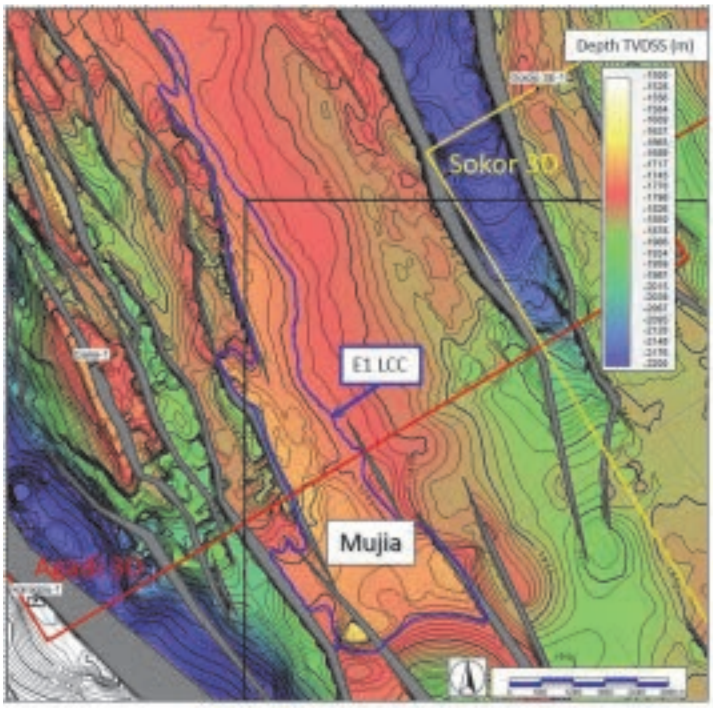

Figure 2.22 Sokor Alternances E1 Depth Map over the Mujia Lead

3 RESOURCE ESTIMATION

3.1 Prospects and leads

CGG has reviewed exploration prospects and leads identified by Savannah.

The principal conclusions of our review of these prospects and leads are that: (1) the methodology used by Savannah to estimate gross mean unrisked prospective STOIIP volumes on these prospects and leads has been assessed as reasonable; (2) in aggregate, the structural prospects and leads we assessed are seen as carrying a low exploration risk profile (i.e. we see as carrying a similar risk profile to those drilled elsewhere in the basin to date).

In detail the basis for sand thickness, porosity, oil saturation and FVF values were found to be reasonable. Minimum and maximum areas of accumulation were, in almost all cases, also found reasonable, or were slightly modified by CGG for this review. CGG considered that Savanah's "Best Estimate" accumulation areas were conservative in relation to maximum trap areas. This does not impact our view that the Savannah approach is reasonable for the prospects and leads, but does imply that the traps are not filled to spill. The geological implications of this are discussed further in discussion of "yet-to-find".

The CGG depositional model summarised in Section 2.2, implies that "layer cake" geometries may apply to many of the reservoirs. Section 4.2 describes CGG's engineering-based evaluation of Recovery Factor ranges that are considered reasonable for the basin. Both approaches suggest that Recovery Factors could be relatively high. CGG has concluded that a Recovery Factor of 34% should be used as a "Mid Case" for the purposes of this evaluation.

The existence of a stratigraphic play or plays across the basin could add a significant amount of potential resource, particularly in those areas where structural trapping and fault density are less apparent. Potential stratigraphic traps can be demonstrated to exist over large areas where sand distribution is likely to be controlled by subtle changes in thickness, facies type and topography. This is particularly the case where up-dip pinchouts have been mapped by Savannah, such as the Yogou interval across large parts of the R2 Licence Area.

3.1.1 Geological uncertainty

CGG is generally in agreement with Savannah's mapping of prospects and leads in terms of minimum and maximum closure areas. When CGG's maximum closure areas are run on a fill-to-spill basis, the resulting unrisked STOIIP's are much larger than expected from Savannah's field size distribution for the basin. This supports the concept that many of the traps in the upper levels of the petroleum system in the Agadem Rift Basin may not be filled to spill, and justifies Savannah's approach to mapping accumulation areas.

Savannah's proprietary geochemical modelling made available to CGG shows that the source systems in the Agadem Rift Basin started generating oil relatively recently: Donga and Yogou - mid Cenozoic to present day, base Sokor - Miocene to present day and main body of the Sokor section - Miocene to present day (but confined to the Dinga Trough). The modelled volumes of oil expelled are very large, at up to: 60 mmbbl/km^2 (Donga), 80 mmbbl/km^2 (Lower Yogou), 97 mmbbl/km^2 (Top Yogou), 50 mmbbl/km^2 (Base Sokor), 30 mmbbl/km^2 (Sokor in the Dinga Trough).

These volume estimates suggest that the basin has generated far more oil than is required to fill the traps to spill. There are two possible explanations for why the traps are not filled to spill. First, despite the relatively recent timing of oil generation, much of the oil may have leaked to surface. If this was the case, a high proportion of the wells drilled to date would have encountered bitumen whilst drilling through the shallow section. CGG is not aware of any accounts of substantial bitumen deposits in the uphole sections of these wells. Second, much of the oil has been retained in traps in the deeper, largely undrilled, sections – this is the explanation preferred by CGG.

CGG therefore considers the interpreted lack of fill to spill at individual traps to be due either due to leakage through the fault seals to traps at higher levels, or because of charge limitations. The charge limitations seem likely to be due either to the position of the trap on local migration pathways or to retention of oil at deeper levels.

The importance of recognising that the traps are probably larger than the mapped accumulations becomes significant when considering yet-to-find in the deeper parts of the basin – where seals are likely to be better and the traps are closer to the mature source systems. Consequently, the deeper traps are more likely to be filled to spill where charge volumes are adequate.

3.1.2 Risk factors

The standard industry methodology of assigning the different components of the petroleum system a probability has been employed. The product of these components then provides an estimate of the overall chance of successfully encountering hydrocarbons at the target (i.e. the geological chance of success).

Note that for the purposes of this evaluation, CGG defines a 'target' as a potentially hydrocarbon-filled trap at a specific stratigraphic level (e.g. Sokor Alternances or Upper Yogou). One prospect or lead may incorporate many stacked targets, and these may be evaluated by a single exploration well. Savannah has previously used the term 'target' in a different way to define the wrapped-up volume that incorporates all prospective reservoir intervals.

Most of the petroleum system elements are interpreted to be operating successfully for each prospect or lead. CGG considers that the greatest sources of risk at each target are potential leakage through fault seals, and specific migration pathways/local charge volumes. In terms of the wrapped-up volume, the question of which target or targets will retain hydrocarbons represents uncertainty, not risk.

These elements are to some extent independent: geometries of juxtaposition of sand against shale, or the extent of shale smear on the fault, may mean that hydrocarbon is trapped in one target, whereas the seal for an underlying or overlying target may be breached.

In order to account for the multiple horizons in each prospect, the range of STOIIP and geological chance of success has been calculated for each target. These have then been combined probabilistically to derive an unrisked and risked distribution of STOIIP for each prospect.

3.1.3 STOIIP and resource estimation

The table below summarises CGG's assessment of the STOIIP and recoverable resources for the prospects and leads shown in Figure 2.13. Recovery factors of 29%, 34% and 39% have been associated with the P90, P50 and P10 probabilistically derived STOIIP cases respectively, in order to calculate recoverable resources. The derivation of these recovery factors is explained in Section 4.0 (Reservoir Engineering).

Table 3.1 Unrisked STOIIP by Prospect and Lead

		STOIIP, mmbbl			
Prospect/lead	**Horizon**	**P90**	**P50**	**P10**	**Mean**
Bushiya	Upper Sokor	22	92	232	112
	Alternances	16	71	169	84
	Total	**19**	**85**	**215**	**105**
Amdigh	Upper Sokor	15	62	153	74
	Alternances	22	86	190	97
	Total	**27**	**100**	**220**	**114**
Eridal	Upper Sokor	15	68	172	82
	Alternances	10	39	83	43
	Total	**13**	**48**	**130**	**62**
Kunama	Upper Sokor	70	207	416	229
	Alternances	22	64	124	69
	Total	**24**	**72**	**212**	**102**
Kiski	Alternances	8	36	130	56
	Total	**8**	**36**	**130**	**56**
Damissa	Upper Sokor	29	136	342	163
	Alternances	27	134	599	241
	Yogou	73	215	432	235
	Total	**32**	**235**	**668**	**296**
Mena	Upper Sokor	9	39	98	47
	Alternances	31	122	344	160
	Yogou	5	9	14	9
	Total	**13**	**97**	**338**	**147**
Mujia	Upper Sokor	31	143	367	175
	Sokor	29	117	277	138
	Yogou	2	7	15	8
	Total	**15**	**135**	**357**	**167**
Efital	Upper Sokor	54	159	324	177
	Sokor	75	201	389	220
	Yogou	18	41	74	44
	Total	**40**	**205**	**450**	**228**

Notes:

1. *The volumes for individual stratigraphic horizons and prospect totals are calculated probabilistically*

Table 3.2 Unrisked Prospective Resources by Prospect and Lead

		Unrisked Recoverable Resources, mmbbl				
Prospect/lead	**Horizon**	**P90**	**P50**	**P10**	**Mean**	**Risk factor**
Bushiya	Upper Sokor	6	31	90	38	high
	Alternances	5	24	66	28	low
	Total	**6**	**29**	**84**	**36**	**low**
Amdigh	Upper Sokor	4	21	60	25	high
	Alternances	6	29	74	33	low
	Total	**8**	**34**	**86**	**39**	**low**
Eridal	Upper Sokor	4	23	67	28	high
	Alternances	3	13	32	15	low
	Total	**4**	**16**	**51**	**21**	**low**
Kunama	Upper Sokor	20	70	162	78	high
	Alternances	6	22	48	24	low
	Total	**7**	**25**	**83**	**35**	**low**
Kiski	Alternances	2	12	51	19	low
	Total	**2**	**12**	**51**	**19**	**low**
Damissa	Upper Sokor	8	46	133	55	high
	Alternances	8	46	234	82	medium
	Yogou	21	73	168	80	high
	Total	**9**	**80**	**261**	**101**	**low**
Mena	Upper Sokor	2	13	38	16	high
	Alternances	9	41	134	54	medium
	Yogou	1	3	6	3	medium
	Total	**4**	**33**	**132**	**50**	**low**
Mujia	Upper Sokor	9	49	143	59	high
	Sokor	8	40	108	47	low
	Yogou	1	2	6	3	medium
	Total	**4**	**46**	**139**	**57**	**low**
Efital	Upper Sokor	16	54	126	60	high
	Sokor	22	68	152	75	medium
	Yogou	5	14	29	15	medium
	Total	**12**	**70**	**175**	**77**	**low**

Notes:

1. *The volumes for individual stratigraphic horizons and prospect totals are calculated probabilistically*
2. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
3. *Risk factors: low = > 75%, medium = 25% - 75%, high = <25%*

3.2 Yet-to-find analysis

The starting point for this analysis was the existing basin discovery density data which were then extrapolated into Savannah's acreage on the basis of structural domains. In the light of the available exploration data, CGG then estimated a geological adjustment factor to allow for variations within the structural domains that could affect prospect density and size. This includes lateral changes in fault density (which could affect prospect density in these predominantly structural traps) and vertical changes in structure and trap quality, that could mean that trap sizes are different from those in the Sokor Alternances (the discovery density data is derived almost entirely from drilling in the Sokor Alternances).

CGG then applied standard geological risking for Source, Reservoir, Charge, Trap and Preservation in order to estimate the chance of each play being successful in each structural domain in each licence area. The below Table 3.2 summarises our overall assessment of the Low, Best and High Case estimates, both unrisked and risked, for the areas R1/R2 and R3/R4.

Table 3.2 Unrisked and risked gross "Yet to Find" prospective resource estimates

License	Play	Prospective Resources (MMBO) Gross	Prospective Resources (MMBO) Gross	Prospective Resources (MMBO) Gross	Risked Prospective Resources (MMBO) Gross	Risked Prospective Resources (MMBO) Gross	Risked Prospective Resources (MMBO) Gross
		Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
R1/R2	Upper Sokor	289	760	1133	81	213	318
R1/R2	Sokor Alternances	416	1094	1630	230	605	901
R1/R2	Yogou	444	1169	1742	201	530	789
R1/R2	Lower Yogou & Donga	459	1208	1800	127	334	497
TOTAL R1/R2	All 4 plays	1608	4231	6304	639	1682	2505
R3/R4	Upper Sokor	211	554	826	49	130	193
R3/R4	Sokor Alternances	252	664	990	156	410	611
R3/R4	Yogou	274	721	1074	146	385	574
R3/R4	Lower Yogou & Donga	288	757	1128	81	214	320
TOTAL R3/R4	All 4 plays	1025	2696	4018	433	1139	1698
TOTAL R1/R2, R3/R4	All 4 plays	2632	6927	10322	1072	2821	4203

Across the areas as a whole, the estimated average play geological chance of success (GCOS) in exploration terms is high.

The lower chances of geological chance of success estimated for the other plays mostly reflects uncertainty due to the limited amount of properly targeted drilling of those levels, rather than specific negative geological information.

4 RESERVOIR ENGINEERING

The main objective of CGG's reservoir engineering work was to provide an independent assessment of Savannah's estimated recovery per well (EUR/well) and recovery factor estimation. The following sections summarise the analysis.

4.1 Ultimate recovery per well (EUR/well) estimation

4.1.1 Decline Curve Analysis

EUR/well is an important parameter used to determine the number of wells required for optimum field development. CGG has reviewed the production performance of the neighbouring producing fields in the Agadem Rift Basin.

CGG has performed production data analysis to determine the future field potential. Arp's decline curve analysis (DCA) technique was used to determine the reserves and forecast production.

CGG has analysed the monthly averaged production data to determine current performance and to forecast the future performance. Well by well historical production decline were analysed to determine the historic decline rates using the rate vs. cumulative oil production and water cut vs. cumulative oil production techniques.

The estimated EUR/well using this decline curve analysis ranged from 2.2 to 2.4 MMstb/well. The production from these analogue fields has been constrained due to refinery capacity, and the field developments are based on natural aquifer support with limited water injection, It is due to this sub-optimal development that CGG characterise these EURs as P90 (low case).

Higher EUR can be anticipated from the wells by improving the artificial lift performance and perforation strategy

4.1.2 Simulation studies

Savannah has performed a simulation study based on three nearby producing fields analogous to prospects and leads in its acreage. The main aim of the study was to improve the understanding of field behaviour and to estimate the production potential of the fields under an optimised field development plan. Static (geological) models were first constructed honouring available seismic and well data. Models were populated with an initial set of rock properties based on Savannah's geological understanding of likely reservoir quality and distribution given the depositional environment in the three fields. These models were then passed to dynamic simulation where the properties were altered in order to better match known field behaviours. A number of key insights were gained through the modelling study, including:

- STOIIP's were under-estimated in initial static models, requiring increased NTG to match dynamic field behaviour
- Insights were gained into variance in field connectivity due to faulting and stratigraphic components
- The likely presence of "fault shadows" in the seismic was noted in some instances leading to some faults being removed, indicating improved connectivity vs. initial models
- Permeabilities and oil saturations were typically higher than first estimated from static modelling
- Fields have been sub-optimally developed in regards to water-injection, liquid offtake, infill drilling density and perforation strategy. Simulation was able to demonstrate increased field recovery potential if these factors can be better optimised.
- Primary geological controls on recovery factor we found to be reservoir connectivity, reservoir quality and the degree to which aquifer/injection support was baffled from production wells.

Ultimate recovery factors achieved in the three optimised models were 29%, 38% and 39%.

4.1.3 EUR/well conclusions

The EUR/well from various estimates are summarised below in Table 4.1. CGG has considered simulation based average EUR/well estimates as the upside or P10 potential for the fields whilst DCA estimates which suffer from historical facility constraint issues are considered to be the lowside or P90 outcome.

Table 4.1 EUR/well for producing fields using simulation study

EUR/well method (MMSTB)	Range	Average
DCA (P90)	2.2 – 2.4	2.3
Simulation (P10)	1.6 - 3.8	3.0

In order to determine the most likely case (P50) EUR/well CGG has used an average EUR/well from DCA production analysis and simulation study. The estimated EUR/well is **2.7 MMSTB**. It should be noted that Savannah has utilised a conservative EUR/well to generate production profiles and perform economics, as described in Sections 4 and 5. A comparison of these values with CGG's estimate is shown in Table 4.2 for Savannah's proposed pipeline and trucking oil export options. Further details of the export options are provided in Section 5.0.

Table 4.2 Summary of most likely EUR/well

Case	CGG estimate	Pipeline Cases	Trucking Cases
EUR/well method (MMSTB)	2.7	2.6	2.5

4.2 Recovery factor estimation

The recovery factor is the recoverable amount of hydrocarbon-initially-in-place, normally expressed as a percentage. The main objective of this section is to determine benchmark recovery factors for the prospect reservoirs and compare it with the analogue reservoir's recovery factors. As discussed in section 4.1, Savanah performed a simulation study based on three nearby producing fields analogous to the prospects and leads in its acreage. Ultimate recovery factors achieved in the three optimised models were 29%, 38% and 39%.

CGG has used two analogue-based approaches to assess whether these recovery factors estimated from Savannah's simulation study are reasonable:

- Empirical correlations
- Analogue reservoir performance

4.2.1 Empirical correlation

There are several empirical relationships in the literature which are often used for quick performance predictions. In the correlations oil recovery was related to the permeability, porosity, oil viscosity, formation thickness, connate water saturation, depth, oil reservoir volume factor, area, and well spacing.

The following empirical correlations were applied to the fields studied in the Savannah simulation work:

- Arp's (Arp's et al. 1967)[2]
- Guthrie and Greenberger et al.1955[3]

A summary of the recovery factors derived from the empirical equations is shown in Table 4.3.

Table 4.3 Summary of recovery factor estimation using empirical correlation

Method	Range of Recovery Factor Results
Arp's API correlation	26.7 - 51.1
Guthrie & Greenberger correlation	37.7 - 52.6

The estimated recovery factors using correlations indicate that Savanah has used conservative recovery factors that increase the confidence in simulation results.

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[2] API Correlations - (Arps-1967 & Doscher-1984)
[3] Statistical Analysis by Guthrie & Greenberger-1955 (Craze & Buckley-1945)
*SPE PRMS 2007

4.2.2 Analogue reservoir performance

Analogue reservoirs were selected based on criteria specified by SPE PRMS*. SPE PRMS has defined analogue reservoir as follows:

Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.

The Society of Petroleum Engineers (SPE) suggests that the production lifecycle of an oilfield is characterized by three main stages: production build-up, plateau production, and declining production. For oil reservoirs, primary recovery (i.e., natural depletion of reservoir pressure), the lifecycle is generally short and the recovery factor does not exceed 20% in most cases. For secondary recovery, relying on either natural or artificial water or gas injection, the incremental recovery ranges from 15 to 25%. Waterflooding can help to improve the recovery factor of maturing assets by 10 to 30%. Globally, the overall recovery factor for combined primary and secondary recovery range between 35 and 45%[4].

CGG has compared the recovery factor with analogue reservoirs[5]. Waterflooding is planned in the prospective reservoirs. The average recovery factor for a water flooded oil reservoir is approximately. 46%[6]. The estimated range of recovery factors for the analogue reservoirs used in the simulation study performed by Savannah is 29 to 39%, which lies well within the range specified by SPE for waterflooded oil reservoirs.

4.2.3 Recommendation on recovery factor

The following range of recovery factors are used by CGG for resource estimation. This lies within range specified by empirical correlation and analogue reservoirs.

Table 4.4 Summary of recovery factor used for resource assessment

Case	Source	R.F. %
Low	Lowest simulated recovery factor (most challenging geological analogue studied)	29.0
Mid	Average of Low & High Estimates	34.0
High	Highest simulated recovery factor (most favourable geological analogue studied)	39.0

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[4] http://www.spe.org/industry/increasing-hydrocarbon-recovery-factors.php (Dated: 25th July, 2017)
[5] IOR for Deepwater Gulf of Mexico, J Lach et. Al. Research Partnership to Secure Energy for America, RPSEA
[6] History of North Sea oil recovery. Mike Shepherd www.devex-conference.org/perch/resources/mike-shepherd-devex-2016.pdf (Dated: 25th July, 2017)

DEVELOPMENT SCENARIOS

As the R1/R2 and R3/R4 Licence Areas are still in the exploration phase, Savannah has performed a conceptual study for the development of a cluster of notional discoveries (totalling 73 mmbbl recoverable oil), assumed to be located in the R3 Licence Area. This is where Savannah expect to start their drilling campaign and the notional discoveries are intended to approximately replicate the identified prospects and leads.

This conceptual development is described and reviewed by CGG in the following sections.

4.3 Development concept

A "hub and spoke" development concept has been proposed by Savannah, based on existing developments in the basin. The key components of the development are listed below and illustrated in Figure 5.1.

- a Central Processing Facility (CPF)
- satellite Field Processing Facilities (FPF), typically within 50km of the CPF
- Gathering stations that collect production from individual wells before transport to the FPFs
- Export of crude by either pipeline (a combination of new and/or existing) or trucking.

The notional development assumes two fields of 47 mmbbl and 21 mmbbl STOIIP tied back to the CPF, with a further two fields of 49 MMbbl and 125 mmbbl STOIIP tied back to the FPF. Savannah has applied a 30% recovery factor to these in-place values to determine recoverable oil values based on field modelling.

The facilities will also utilise leased Early Production Facilities (EPF), which will permit early revenues before the permanent facilities are fully commissioned.

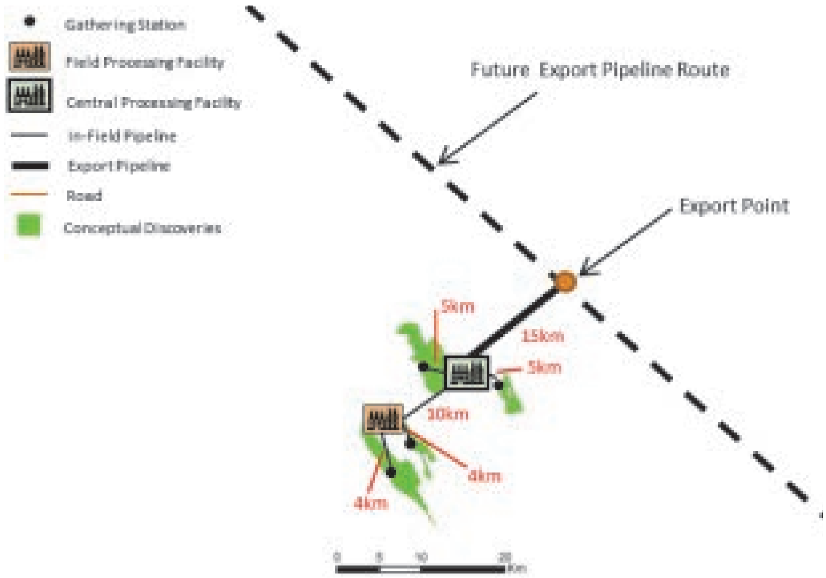

Figure 4.1 'Hub and Spoke' conceptual development option (Source: Savannah)

Production is expected to consist of a moderately viscous crude oil with minimal sulphur content. The measured API from a number of discoveries made in the basin ranges from 16º to 43º, and is typically correlated with depth. For the conceptual development, an average API of 29º was assumed, which is representative of the expected crude blend of a development. Oil quality uncertainty and wax-presence risk has been explicitly studied by Savannah with detailed flow assurance calculations. Heaters to ensure flow assurance are included in cost estimates for the CPF, gathering stations and major export lines.

Only small quantities of associated gas are expected, however larger quantities would offer economic benefits by providing fuel gas for plant operations (and reducing diesel consumption), and in an upside case by providing injection gas to enhance oil production.

All production wells are assumed to be fitted with electrical submersible pumps (ESPs) and with one water injector assumed for every three production wells. Water injection is assumed to be required in two thirds of the fields, with aquifer support in the remaining fields. The cost of these items and supporting equipment has been included in the cost estimates.

CGG has reviewed the proposed development solution and consider it to be an appropriate solution for the anticipated discoveries.

4.4 Export options

Existing production in the Agadem Rift Basin is currently transported through a 463 km pipeline to the Zinder refinery, located in the south of Niger. However, this refinery has a nominal capacity of approximately only 20,000 bpd. As this capacity is fully allocated, Savannah production will require alternative evacuation routes.

A number of export routes and destinations have therefore been examined by Savannah, of which the three main candidates are:

1. Kribi Oil Terminal (Cameroon) via a new c. 800km pipeline constructed by CNPC to the existing Chad-Cameroon pipeline.
2. Kaduna Refinery (Nigeria) via a new c. 800km pipeline built by third parties
3. Kaduna Refinery (Nigeria) via the existing domestic pipeline, and then by road trucking to Kaduna

The export routes considered by Savannah are shown in the Figure 5.2.

Figure 4.2 Export Route Options (source Savannah)

The current capacity of the Chad-Cameroon line is 225,000 barrels per day, however, it is understood that this can be increased with the addition of further pumping stations. Savannah has stated that there is currently significant spare capacity in the line.

The R1/R2 and R3/R4 PSCs, and the Petroleum Code of Niger, guarantee Savannah access to third party owned infrastructure, including the proposed extension of the Chad-Cameroon pipeline extension into Niger and the contemplated pipeline to northern Nigeria. Furthermore, the PSCs set out the terms for calculating pipeline transportation tariffs and limit the Transport Contractor's internal rate of return from tariffs to 12.5%.

The Kaduna refinery has a nameplate capacity of 110,000 barrels per day, and is only currently being utilised at 30-40% of available capacity. The main reason for this being infrastructure issues on the supply pipeline from Warri. Refinery management are keen to have alternative supplies of crude to enable higher utilisation rates.

Trucking of crude oil over long distances, and across international borders, can be problematic for security, safety, social, and environmental reasons. Study work carried out by Savannah has indicated that trucking is feasible and that these risks can be mitigated. It is noted that other operators and service providers in the ARB have transported a large number of heavy freight loads in the area, as well as regular diesel supplies to the producing fields. Furthermore, trucking of crude oil over large distances, and in much higher quantities, is carried out profitably in other regions (e.g. Kurdistan Region of Iraq).

4.5 Capital and Operating costs

Savannah has developed detailed estimates of capital and operating costs for the three export options. Costs are developed in consideration of the fact that there are already three producing fields in the basin, numerous exploration wells, a "tried and tested" petroleum regulatory framework, drilling rigs, trained and experienced labour, equipment suppliers and service companies. The regional terrain is also favourable for petroleum operations, being dry, sparsely populated and with minimal dunes.

Capital costs are based on industry norms and include the following facilities and equipment:-

- Drilling & well completions
- Water treatment
- Power generation
- Oil stabilisation
- Water injection
- Fiscal metering
- Flow assurance
- Gathering lines
- Tie-in lines to export pipelines

Operating costs have been calculated on a dollar per barrel basis, are based on operating costs reported to date, and are deemed to include personnel, consumables, chemicals, maintenance, diesel, camp, logistics and warehouse, ESP work-over and security costs.

The trucking costs assume a 50,000 litre truck and trailer combination with a round trip of 500km taking approximately two days. The procurement cost of the trucks is included in the capital cost estimate. The associated operating costs include fuel, maintenance, driver's wages, and military escorts.

The assumed pipeline tariffs per barrel are based on indicative high-level estimates derived from similar infrastructure. The truck operating costs have been converted into an equivalent per barrel tariff.

The table below summarises the estimated costs in US dollars. The tabulated capital costs exclude 4% Niger import duty, which is applied as a factor at the economic analysis stage.

Table 4.5 Capital and Operating Cost Summary by Option

Export option	Wells Capex ($MM)	Facilities Capex ($MM)	Total Capex ($MM)	Field Opex ($MM)	Export opex/tariff ($/bbl)
Pipeline to Cameroon	221	190	411	595	16
Pipeline to Kaduna	221	190	411	595	5
Trucking to Kaduna	221	206	427	561	6

Capital and field operating costs are estimated to be approximately $6/bbl and $8/bbl respectively.

In addition, abandonment costs of approximately $58MM have been assumed based on facilities removal and abandonment costs of $1.0MM per well.

CGG has reviewed the costs and tariffs, and consider them to be reasonable and consistent with analogue development projects in the region.

4.6 Drilling

Savannah is proposing simple vertical or slightly deviated wells, in order to target the anticipated stacked reservoirs. This type of well is a proven development solution in the existing fields in Niger.

No major difficulties for drilling are therefore anticipated, particularly when the following aspects are also included:

- Development wells are not expected to be excessively deep, ranging from 2,000m to 2,600m (total vertical depth from ground level).
- Minimal to no sulphur content is expected to be encountered in the wells
- Reservoir pressures and temperatures are expected to be normal.
- Drill times expected to be about 30 to 35 days (including production completion)
- Rig moves between drilling locations in relatively flat and accessible terrain are expected to be between 7 to 10 days
- Proven logistics and oil service industry

Drilling is likely to be performed by a competitively priced and experienced contractor, which together with the above factors will result in relatively low-cost wells. Savannah has contracted a drilling rig for the upcoming drilling campaign from Great Wall Drilling Company Niger SARL, who have experience of drilling over 200 wells in the ARB to date.

A phased approach to drilling ("batch drilling") is also planned by Savannah. Batch drilling saves time, when there is a relatively large number of similar wells to drill. The phased "batch" approach to drilling is expected to proceed as follows:

- Phase I: Use a full-size drilling rig. Perform main drilling of a "batch" of wells to full depth, wireline log, take sidewall cores and sample as required, and then suspend for later re-entry (if not dry).
- Phase II: Use a smaller dedicated testing rig to perform wellbore clean-up and well test as required on a "batch" of wells.
- Phase III: Use a smaller work-over rig to complete a batch of wells, ready for production.

On this basis, production wells are estimated to cost $5.8MM, and injection wells $4.8MM. It is assumed that ten wells are drilled by one rig in a year. All wells will be subject to wireline logging, with 70% tested using Drill Stem Testing (DST). All successful exploration and appraisal wells are assumed to be re-used as producers.

4.7 Schedule

A fast-track exploration, appraisal and development programme is planned by Savannah, with first production scheduled in late 2020. This is three years from the start of the exploration campaign, and assumes the drilling of successful exploration wells in early 2018. It is understood from Savannah that the exploration drilling is on schedule at the time of writing.

The first oil date is deemed to be achievable provided the export routes are completed in time. However, with the exception of the trucking option, these are under the control of third parties, and will require cross-border and commercial agreements to be successfully concluded. CNPC are understood to be about to commence study work on possible export pipeline options, and are currently scheduling pipeline completion in 2020.

The risk of export pipelines not being completed on time may be mitigated by using the trucking option to the Kaduna refinery on a temporary basis until the infrastructure is completed.

4.8 Security

Security is a major consideration for petroleum operations in the region, in terms of personnel safety, development and operating costs, schedule delays, and damage to property.

However, CGG understand that Savannah has carried out a comprehensive risk assessment, which has been informed by many years of exploration and production operations by others in the region, and by four years of Savannah's own operations. Based upon this assessment, and the use of appropriate security measures, Savannah believes that the existing security situation can be managed to within acceptable limits.

Savannah has included the cost of providing military escorts and security personnel during production and export operations in their operating cost estimates.

4.9 Production profiles

Oil production and water injection profiles were provided by Savannah in an Excel spreadsheet. This included the desired number of producer and injection wells. A Material Balance (MBAL) model was used by Savannah for forecasting the oil production rates. Table 4.6 below summarises the main characteristics of the three options being considered by Savannah.

Table 4.6 Characteristics of main development scenarios

Case / Export Route	Peak Oil Production (Stb/D)	Water Supply Wells	E&A Wells (Converted To Future Producers)	Dedicated Production Wells	Dedicated Injection Wells	Total Wells Drilled
Pipeline to Cameroon	18,000	4	11	17	11	43
Pipeline to Kaduna	18,000	4	11	17	11	43
Trucking to Kaduna	10,000	4	11	17	11	43

Table 4.7 table below provides a summary of the EUR/well and maximum oil rate estimated by Savannah

Table 4.7 EUR/well and oil rate comparison

Category	Units	Pipeline Cases	Trucking Case
EUR	MMBO	73.5	69.7
Total Number of producing wells		28	28
EUR/well	MMBO	2.6	2.5
Peak oil rate	STB/day	18000	10000
Number of wells producing @ peak prod		11	11
Max oil rate/well	STB/day	1636	909

Detailed discussion on EUR/well is presented in Section 4. The most likely case (P50) EUR/well is 2.7 MMSTB as shown in Table 4.2 EUR/well values resulting from Savannah modelling are considered conservative.

Similarly the maximum anticipated oil rates per well for the pipeline and trucking cases are 1636 and 909 STB/day respectively. The oil production rates are in reasonable agreement with production performance of analogue wells.

Table 5.4 below provides a summary of the injection well requirement. The injection profiles were determined by Savanah, using MBAL software, based on a 100% voidage replacement. The water production and injection rates are deemed by CGG to be reasonable.

Table 4.8 Injection well summary

Case	Peak Oil Rate	Peak Liquid Rate	Peak Injection Rate	Peak Injection Shortfall*	Water Supply Wells Drilled	Water Production rate/well
	stb/d	stb/d	stb/d	stb/d		stb/d
Pipeline Cases	18000	55000	55560	18650	4	4,663
Trucking Case	10000	55000	55310	10430	4	2,608

* Water injected minus water produced, i.e. requirement for input from water supply wells.

5 INDICATIVE ECONOMICS

5.1 Methodology

CGG has calculated indicative economics for the notional 73 MMbbl development described in Section 5 for the three options under a range of input assumptions.

It should be noted that this conceptual development solution and the associated costs and economic analysis is not directly representative of Savannah's planned exploration campaign. It represents an assumption of how any discoveries made as part of Savannah's planned exploration campaign could potentially be developed, but final development plans and work programmes will be subject to analysis of the results of Savannah's planned drilling campaign.

Economics have been calculated using a standard discounted cash flow model developed in Excel™ that honours the fiscal terms applicable to the licence areas.

5.2 Input assumptions

5.2.1 Fiscal terms

Savannah's licences are subject to two different sets of fiscal terms.

- The R1/R2 Licence Area is subject to a Production Sharing Contract (PSC) between Savannah Petroleum Niger R1/R2 S.A. (the Contractor) and the Republic of Niger.
- The R3/R4 Licence Area is subject to a Production Sharing Contract (PSC) between Savannah Petroleum Niger R1/R2 S.A. (the Contractor) and the Republic of Niger.

Savannah has a 95% interest in the Contractor in both PSCs.

The key terms of the two PSCs as understood by CGG are presented in the following sections.

5.2.1.1 Signature bonuses:

- R1/R2 US$34MM of which 40% is cost recoverable
- R3/R4 US$28MM of which 60% is cost recoverable

These were paid at the signing of the two contracts.

5.2.1.2 Royalties:

There is an oil royalty of 12.5% levied on the gross sales revenue less export pipeline costs.

5.2.1.3 Cost Oil:

Exploration, capital and operating costs can be recovered from 70% of gross revenues less royalties. Unrecovered costs in any year can be carried forwards.

5.2.1.4 Profit oil:

Profit oil is shared between the State and Savannah depending on the value of an R-factor as shown in the table below. The R-factor is calculated as follows:-

(cumulative cost and profit oil less exploitation costs)/ (cumulative exploration and capital costs)

Table 5.1 Profit Oil rates

R-Factor	Contractor	State
< 1.0	60%	40%
1.0 – 1.49	55%	45%
1.5 -1.99	50%	50%
> 2.0	45%	55%

5.2.1.5 Corporation tax:

No corporation tax is payable in Niger.

5.2.1.6 State participation:

The state has back-in rights to the licences as follows:

- R1/R2: 20% of profit oil
- R3/R4: 15% of profit oil

5.2.2 Oil prices

The Base Oil prove that has been used is $60/bbl Brent oil price escalating at 2% per year

The other oil price deck used is the Brent forward curve as of 31st July 2017. Beyond the range of the present forward curve, oil prices are assumed to escalate at 2% per year.

In order to capture oil price uncertainty, low and high price decks have been taken as +/- 5% for 2017, +/- 10% for 2018, and +/-15% for 2019 onwards. The narrower near-term range reflects the greater certainty of near-term pricing.

It is assumed that production is sold at the delivery point at the Brent price less a 5% discount.

Table 5.2 Brent forward curve as of 31st July 2017 assumptions

	Brent Price $/bbl (nominal)		
	Base	Low	High
2017	52.4	49.8	55.0
2018	52.9	47.6	58.2
2019	53.5	45.5	61.5
2020	54.3	46.2	62.5
2021	55.4	47.1	63.7
2022	56.7	48.2	65.2
2023	57.9	49.2	66.5
2024	58.6	49.8	67.4
2025+	+2%	+2%	+2%

5.2.3 Inter-company loan

As the PSCs permit the recovery of loan interest at the reference rate (assumed to be US LIBOR) plus 10%, an inter-company loan will be used by Savannah to finance the construction of the project. The interest can be cost recovered through the PSCs, and it can be netted out at a corporate level between subsidiaries with no overall cash flow impact. This arrangement has been included in the economic evaluation.

5.2.4 Other

Other assumptions used by CGG in the economic evaluation are tabulated below.

Table 5.3 Other assumptions

Parameter	Value
Discount Factor	10%
Discount Methodology	Mid-Year
Cost Inflation[1]	2% per annum
Discount Date	1 January 2018

1.Savannah believe that they will be able to "lock into" current contract rates for the early phases of the development, and therefore capex for these phases has not been inflated in the evaluation.

5.3 Results

Economics have been determined for the generic 73 mmbbl development. The economics presented are net to Savannah's 95% interest. The analysis assumes that all exploration wells are successful and are converted to producers.

Results are tabulated below for development options 1, 2 and 3 under the R3/R4 PSC terms at the $60/bbl base oil price.

Table 5.4 Indicative economics (net Savannah) for generic development (base price) $60

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
NPV0 ($MM)	801	1132	1093
NPV10 ($MM)	252	386	269
IRR (%)	32.2%	44.0%	26.1%
NPV/bbl ($)	3.6	5.5	4.1

Individual NPV10 sensitivities for each option have also been performed for +30%/-15% factor on costs, a one year delay to first production from 2020 to 2021, and low and high oil price outcomes respectively.

Table 5.5 Generic development - economic sensitivities for $60/bbl (NPV10, $MM)

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
Base case ($60/bbl)	252	386	269
+30% factor on costs	171	315	190
-15% factor on costs	288	405	306
1 year delay to 1st oil	215	339	230
Forward curve -15%	174	287	189
Forward curve +15%	326	461	346

Economics have also been determined for each option for the Brent forward curve as of 31st July 2017 and $50/bbl.

Table 5.6 Indicative economics (net Savannah) for generic development for Brent forward curve as of 31st July 2017

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
NPV0 ($MM)	552	873	855
NPV10 ($MM)	140	281	180
IRR (%)	21.7%	34.9%	20.5%
NPV/bbl ($)	2.0	4.0	2.7

Table 5.7 Indicative economics (net Savannah) for generic development ($50/bbl)

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
NPV0 ($MM)	529	840	825
NPV10 ($MM)	128	267	168
IRR (%)	20.5%	33.5%	19.7%
NPV/bbl ($)	1.8	3.8	2.5

Table 5.8 Generic development - economic sensitivities (NPV10, $MM) Brent forward curve as of 31st July 2017

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
Base	140	281	180
+30% factor on costs	28	203	91
-15% factor on costs	186	319	218
1 year delay to 1st oil	112	240	146
Forward curve -15%	70	203	107
Forward curve +15%	208	362	246

Table 5.9 Generic development - economic sensitivities (NPV10, $MM) for $50/bbl oil price

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
base	128	267	168
costs +30%	1	188	78
costs -15%	171	305	207
1 yr delay	97	227	134
prices -15%	54	190	97
prices +15%	191	345	235

The breakeven oil prices that yield a 10% rate of return for each option were also determined, and are tabulated below:

Table 6.8 Breakeven oil prices by option

Option No.	1	2	3
Description	Cameroon pipeline	Kaduna pipeline	Kaduna trucking
Breakeven price ($/bbl)	43	31	36

The life of field netback cash per barrel have also been calculated for each of the options per working interest barrel, 95% Savannah interest based on economic reserves and this is shown in the table in below. The netbacks are presented on a nominal basis and assume an oil price of US$60/bbl from 2018.

Table 5.10 life of field netback cash per barrel

Option	1	2	3
Transportation	20.5	6.4	8.4
Opex/overheads	11.3	11.3	11.4
Capex/abandonment	7.6	7.6	7.8
Government take/royalty	22.3	31.6	31.5
Netback	11.5	16.2	16.5

APPENDIX A: DEFINITIONS

5.4 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in 1998, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (2007) are presented below.

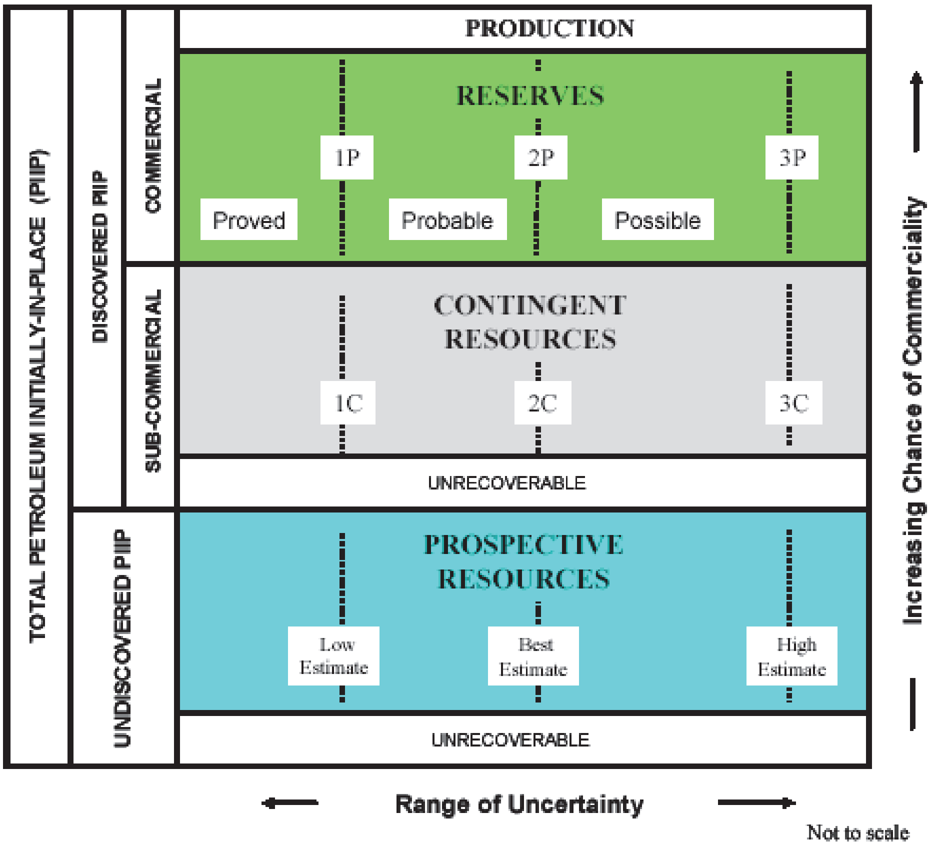

Figure 5.1 Resources Classification Framework

Source: SPE Petroleum Resources Management System 2007

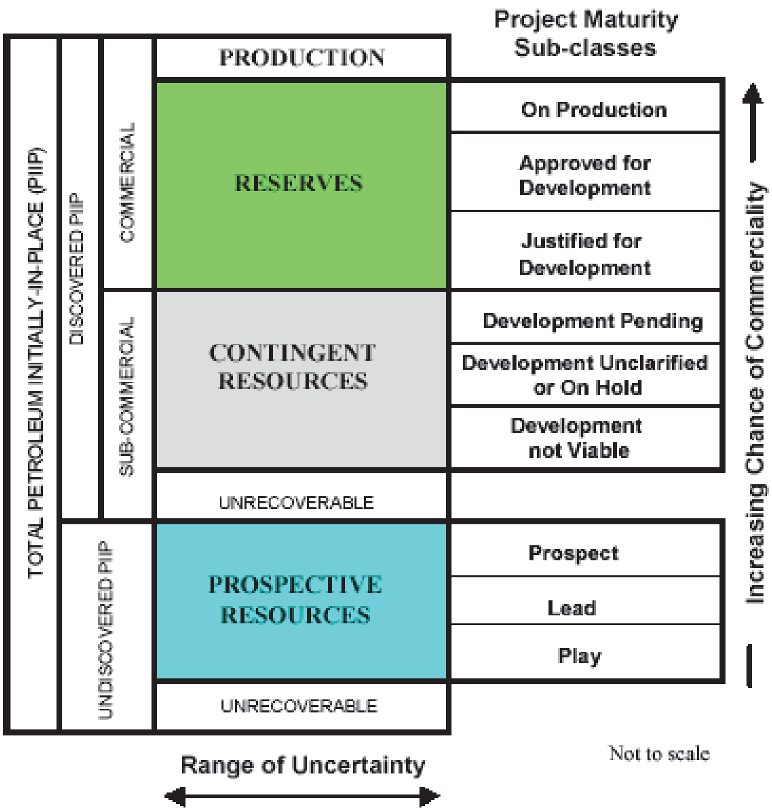

Figure 5.2 Resources Classification Framework: Sub-classes based on Project Maturity

Source: SPE Petroleum Resources Management System 2007

5.4.1 Total Petroleum Initially-In-Place

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”).

5.4.2 Discovered Petroleum Initially-In-Place

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.

5.4.3 Undiscovered Petroleum Initially-In-Place

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.

5.5 Production

Production is the cumulative quantity of petroleum that has been recovered at a given date. Production is measured in terms of the sales product specifications and raw production (sales plus non-sales) quantities required to support engineering analyses based on reservoir voidage.

5.6 Reserves

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations, from a given date forward, under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by development and production status.

The following outlines what is necessary for the definition of Reserve to be applied.

- 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
- There is evidence of firm intention to proceed with development within a reasonable time frame
- A reasonable timetable for development must be in evidence
- There should be a development plan in sufficient detail to support the assessment of commerciality
- A reasonable assessment of the future economics of such development projects meeting defined investment and operating criteria must have been undertaken
- There must be 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

The “decision gate” whereby a Contingent Resource moves to the Reserves class 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.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five 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.

5.6.1 Developed Producing Reserves

Developed Producing Reserves are expected quantities to be recovered from existing wells and facilities. Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

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.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

5.6.2 Developed Non-Producing Reserves

Developed Non-producing Reserves include shut-in and behind-pipe reserves.

Shut-in reserves are expected to be recovered from:

- Completion intervals that are open at the time of the estimate but that have not yet started producing
- Wells that were shut-in for market conditions or pipeline connections, or
- Wells not capable of production for mechanical reasons.

Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion 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.

5.6.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

- From new wells on undrilled acreage in known accumulations
- From deepening existing wells to a different (but known) reservoir
- From infill wells that will increase recovery, or
- Where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to:
    - Recomplete an existing well or

- Install production or transportation facilities for primary or improved recovery projects

Incremental recoveries through improved recovery methods that have yet to be established through routine, commercially successful applications are included as Reserves only after a favourable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program, where the response provides support for the analysis on which the project is based.

Where reserves remain undeveloped beyond a reasonable timeframe, or have remained undeveloped due to repeated postponements, evaluations should be critically reviewed to document reasons for the delay in initiating development and justify retaining these quantities within the Reserves class. While there are specific circumstances where a longer delay is justified, a reasonable time frame is generally considered to be less than five years.

5.6.4 Proved Reserves

Proved Reserves are those quantities of petroleum that, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations.

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.

5.6.5 Probable Reserves

Probable Reserves are those additional reserves that 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 + Probable Reserves (2P).

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.

5.6.6 Possible Reserves

Possible Reserves are those additional reserves that analysis of geoscience and engineering data suggest 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 + Probable + 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.

5.7 Contingent Resources

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

The term accumulation is used to identify an individual body of moveable petroleum. The key requirement in determining whether an accumulation is known (and hence contains Reserves or Contingent Resources) is that each accumulation/reservoir must have been penetrated by a well. In general, the well must have clearly demonstrated the existence of moveable petroleum in that reservoir by flow to surface, or at least some recovery of a sample of petroleum from the well. However, where log and/or core data exist, this may suffice provided there is a good analogy to a nearby, geologically comparable, known accumulation.

Estimated recoverable quantities within such 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.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

Contingent Resources are further categorised in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterised by their economic status.

5.7.1 Contingent Resources: Development Pending

Contingent Resources (Development Pending) are 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 expected to be resolved within a reasonable time frame.

5.7.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are 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.

5.7.3 Contingent Resources: Development Not Viable

Contingent Resources (Development Not Viable) are 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 recognised in the event of a major change in technology or commercial conditions.

5.8 Prospective Resources

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. They 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.

5.8.1 Prospect

A Prospect is classified as a potential accumulation that is constrained by 3D seismic data, and is thus sufficiently well defined to represent a drilling target, without the requirement for further data acquisition.

5.8.2 Lead

A Lead is classified as a potential accumulation that is currently defined on either 2D seismic data, or a mixture of 2D and 3D seismic data. It would benefit from more data acquisition, such as 3D seismic or in-fill 2D, in order to reduce risk and uncertainties.

5.8.3 Play

A Play is classified as a prospective trend of potential accumulations that requires more data acquisition and/or evaluation in order to define specific Leads or Prospects.

5.9 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place quantities that are 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.

6 APPENDIX B: NOMENCLATURE

acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute (°API for oil gravity, API units for gamma ray measurement)
av.	Average
AVO	Amplitude vs. Off-Set
BBO	billion (10^9) barrels of oil
bbl, bbls	barrel, barrels
BCF	billion cubic feet
bcm	billion cubic metres
BCPD	barrels of condensate per day
BHT	bottom hole temperature
BHP	bottom hole pressure
BOE	barrel of oil equivalent, with gas converted at 1 BOE = 6,000 scf
BOPD	barrels of oil per day
BPD	barrels per day
Btu	British thermal units
BV	bulk volume
c.	circa
CCA	conventional core analysis
CD-ROM	compact disc with read only memory
cgm	computer graphics meta file
CNG	compressed natural gas
CO_2	carbon dioxide
COE	crude oil equivalent
1-D, 2-D, 3-D	1-, 2-, 3-dimensions
DHI	direct hydrocarbon indicators
DHC	dry hole cost
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E	East
E & P	exploration & production
EAEG	European Association of Exploration Geophysicists
e.g.	for example
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable (reserves)
FPSO	Floating production storage unit
ft/s	feet per second
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
Ga	billion (10^9) years
GIIP	gas initially in place
GIS	Geographical Information Systems
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
H_2S	hydrogen sulphide
ha	hectare(s)
HI	hydrogen index
HP	high pressure
Hz	hertz
IDC	intangible drilling costs
IOR	improved oil recovery
IRR	internal rate of return
J & A	junked & abandoned
km	kilometres (1,000 metres)
km^2	square kilometres
kWh	kilowatt-hours
LoF	life of field
LP	low pressure
LST	lowstand systems tract
LVL	low-velocity layer
M & A	mergers & acquisitions

m	metres	OAE	oceanic anoxic event
M	thousands	OI	oxygen index
MM	million	OWC	oil-water contact
m^3/day	cubic metres per day	P90	proved
Ma	million years (before present)	P50	proved + probable
mbdf	metres below derrick floor	P10	proved + probable + possible
mbsl	metres below sea level	P & A	plugged & abandoned
MBOPD	thousand bbls of oil per day	pbu	pressure build-up
MCFD	thousand cubic feet per day	perm.	permeability
MCFGD	thousand cubic feet of gas per day	PESGB	Petroleum Exploration Society of Great Britain
mD	millidarcies		
MD	measured depth	pH	-log H ion concentration
mdst.	mudstone	phi	unit grain size measurement
MFS	maximum flooding surface	Ø	porosity
mg/gTOC	units for hydrogen index	plc	public limited company
mGal	milligals	por.	porosity
MHz	megahertz	poroperm	porosity-permeability
million m^3	million cubic metres	ppm	parts per million
ml	millilitres	psi	pounds per square inch
mls	miles	RFT	repeat formation test
MMBO	million bbls of oil	ROI	return on investment
MMBOE	million bbls of oil equivalent	ROP	rate of penetration
MMBOPD	million bbls of oil per day	RT	rotary table
MMCFGD	million cubic feet of gas per day	S	South
MMTOE	million tons of oil equivalent	SCAL	special core analysis
mmsl	metres below mean sea level	SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
mN/m	interfacial tension measured unit		
MPa	megapascals		
mSS	metres subsea	SCF/STB	standard cubic feet per stock tank barrel
m/s	metres per second		
msec	millisecond(s)	SS	sub-sea
MSL	mean sea level	ST	sidetrack (well)
N	north	STB	stock tank barrels
NaCl	sodium chloride	std. dev.	standard deviation
NFW	new field wildcat	STOIIP	stock tank oil initially in place
NGL	natural gas liquids	Sw	water saturation
NPV	net present value	TCF	trillion (10^{12}) cubic feet
no.	number (not #)	TD	total depth
NTG	Net toGross	TDC	tangible drilling costs

Therm	105 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TVDmsl	true vertical depth below MSL
TWT	two-way time
US$	US dollar, the currency of the United States of America
UV	ultra-violet
VDR	virtual dataroom
W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)

PART 13

ADDITIONAL INFORMATION

1 Responsibility

1.1 The Company and its Directors (whose names and functions appear on page 8 of this document) accept responsibility, both individually and collectively, for the information contained in this document. To the best of the knowledge and belief of the Directors and the Company (each of whom has taken all reasonable care to ensure that such is the case), the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information. All the Directors accept individual and collective responsibility for compliance with the AIM Rules.

1.2 Lloyd's Register Group Limited, whose registered address is at 71 Fenchurch Street, London, EC3M 4BS, accepts responsibility for its report set out in Part 11 of this document. To the best of the knowledge and belief of Lloyd's Register Group Limited (which has taken all reasonable care to ensure that such is the case), the information contained in its report is in accordance with the facts and does not omit anything likely to affect the import of such information.

1.3 Robertson (UK) Limited, whose registered address is at CGG UK Imaging Centre UK, Crompton Way, Manor Royal Estate, Crawley, West Sussex, RH10 9QN, accepts responsibility for its report set out in Part 12 of this document. To the best of the knowledge and belief of Robertson (UK) Limited (which has taken all reasonable care to ensure that such is the case), the information contained in its report is in accordance with the facts and does not omit anything likely to affect the import of such information.

2 Incorporation and General

2.1 The Company was incorporated in England and Wales on 3 July 2014, under the name of Savannah Petroleum plc (registered number 9115262), as a public limited company under the Act.

2.2 The Company's registered office and its principal place of business is at 40 Bank Street, London, E14 5NR (telephone number 0203 102 6897 or, if dialling from outside the United Kingdom, +44 203 102 6897).

2.3 The Company is domiciled in the United Kingdom.

2.4 The accounting reference date of the Company is 31 December and will remain so on First Admission and Second Admission.

2.5 The website address for the Company for the purposes of AIM Rule 26 is www.savannah-petroleum.com.

2.6 The principal legislation under which the Company operates, and under which the Placing Shares and the Warrants will be created, is the Act.

2.7 On 22 July 2014, the Company obtained a certificate pursuant to section 761 of the Act entitling it to do business and borrow and on 1 August 2014, the Company's Ordinary Shares were admitted to trading on the AIM Market operated by The London Stock Exchange plc.

2.8 The Company's auditors are Grant Thornton UK LLP, a firm of chartered accountants registered with the Institute of Chartered Accountants in England and Wales.

2.9 The Company is the ultimate holding company of the Group and, from Completion, the Enlarged Group. On restoration of the Existing Ordinary Shares to trading, the Company will have the following subsidiaries and other undertakings:

Name (Jurisdiction)	*Registered Office*	*Principal Activity*	*Issued Share Capital*
Savannah Petroleum 1 Limited (Scotland – SC453751)	50 Lothian Road, Festival Square, Edinburgh, Midlothian, EH3 9WJ	Holding company	1,000,000,020 B ordinary shares of $0.000000001 each and 15,737,894 B ordinary shares of $0.00000001 each
Savannah Petroleum 2 Limited (Scotland – SC467099)	50 Lothian Road, Festival Square, Edinburgh, Midlothian EH3 9WJ	Holding company	105,264 ordinary shares of $0.00001 each
Savannah Petroleum Niger R1/R2 S.A. (Niger-RCCM: NI-NIA-2014-B1940)	61 rue NB-44, BP 07 Quartier Terminus, Niamey, Niger	Exploration and extraction of petroleum & natural gas	1,000 shares of CFA 10,000 each
Savannah Niger Director 1 Limited (Jersey – 115995)	15 Esplanade, St Helier, Jersey, JE1 1RB	Provision of corporate directorial services	2 limited liability shares of £1.00 each
Savannah Niger Director 2 Limited (Jersey – 115996)	15 Esplanade, St Helier, Jersey, JE1 1RB	Provision of corporate directorial services	2 limited liability shares of £1.00 each
Savannah Niger Director 3 Limited (Jersey – 115997)	15 Esplanade, St Helier, Jersey, JE1 1RB	Provision of corporate directorial services	2 limited liability shares of £1.00 each
SPN Limited (Jersey – 117216)	15 Esplanade, St Helier, Jersey, JE1 1RB	Holding company	10,000 limited liability shares of £1.00 each
Savannah Petroleum SAS (France – 811 283 043)	52 Rue de la Victoire, 75009, Paris, France	Services company	1 share of €1.00
Savannah Petroleum International Limited (England – 10344619)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	1 ordinary share of £0.01

2.9.1 The Company owns directly 100 per cent. of the issued shares of DirectorCo 1, DirectorCo 2, DirectorCo 3, SPN and SAS and can exercise 100 per cent. of the voting rights of such companies.

2.9.2 The Company owns 98 per cent. of the issued share capital of SP1L. The remaining two per cent. is owned by directors and senior employees of the Group pursuant to the LTIP, described in paragraph 4.2.

2.9.3 The Company owns indirectly (via SP1L) 100,000 ordinary shares in the capital of SP2L, and Niger Exploration is the holder of 5,264 ordinary shares in the capital of SP2L. The articles of association of SP2L contain a "drag-along" provision pursuant to which SP1L can force Niger Exploration to sell its shares in SP2L in the event SP1L is selling the shares that it owns in SP2L. Niger Exploration is 95 per cent. beneficially owned and 100 per cent. controlled by Yacine Wafy, the Group's Niger Country Manager.

2.9.4 SP2L owns directly 100 per cent. of the issued shares of, and SP2L can exercise 100 per cent. of the voting rights in, Savannah Niger.

2.9.5 Savannah Niger is the principal operating subsidiary of the Group.

2.9.6 Following Completion, the Company will acquire, either directly or indirectly, the following principal subsidiary undertakings:

Name (Jurisdiction)	*Registered Office*	*Principal Activity*	*Percentage Ownership*
Universal Energy Resources Limited (Nigeria – 429120)	25 Idoro Road, Uyo, Akwa Ibom State, Nigeria	Exploration and extraction of petroleum & natural gas	62.5 per cent.
Seven Energy (BVI) Limited (Netherlands – 27307262)	Statutory seat in 's-Gravenhage, the Netherlands and its registered office in 6 Chesterfield Gardens, London W1J 5BQ	Holding Company	100 per cent.
Seven Uquo Gas Limited (Nigeria – 659675)	35 Kofo Aboyomi Street, Victoria Island, Lagos, Nigeria	Exploration and extraction of petroleum & natural gas	100 per cent.

2.10 To facilitate the Transaction, the Company may proceed with the incorporation of a number of new corporate subsidiaries as set out in paragraph 11 of Part 1 of this document.

3 Share Capital

3.1 The capital history of the Company from the date of the Company's incorporation to the date of this document is as follows:

3.1.1 On incorporation, the issued share capital of the Company was £0.01, comprised of ten Ordinary Shares (the **"Subscription Shares"**), legal title in which was owned by LCP1 and beneficial title in which was owned by Andrew Knott.

3.1.2 On 22 July 2014, the Company issued 49,999,991 Ordinary Shares (the **"New Shares"**) pursuant to a Share for Share Exchange Agreement dated on that date. Under the Share for Share Exchange Agreement, LCP1, at that time being the sole registered shareholder of the Company and of SP1L, subscribed for legal title to the New Shares in exchange for the Company's acquisition of the legal title to all 1,000,000,020 B ordinary shares of £0.000000001 each in the capital of SP1L (the **"B Ordinary Shares"**). Following completion of the said share exchange, SP1L was a wholly owned subsidiary of the Company.

3.1.3 On 28 July 2014, legal title in all 50,000,001 issued Ordinary Shares transferred to the holders of the beneficial interests in such Ordinary Shares (other than those 20,591,376 Ordinary Shares in respect of which the beneficial owner requested that LCP1 retained legal title in a nominee capacity).

3.1.4 On 1 August 2014: (i) 25,497,236 Ordinary Shares were issued for an issue price of £0.42 per Ordinary Share pursuant to a debt to equity conversion; and (ii) 55,839,935 Ordinary Shares were issued for an issue price of £0.56 per share as part of the Company's admission to trading on AIM.

3.1.5 On 30 July 2015, 314,275 Ordinary Shares were issued to certain of the Company's Directors and employees by way of bonus remuneration.

3.1.6 On 31 July 2015, 61,690,000 Ordinary Shares were issued for an issue price of £0.38 per Ordinary Share.

3.1.7 On 11 July 2016, 19,334,000 Ordinary Shares were issued for an issue price of £0.38 per Ordinary Share.

3.1.8 On 26 July 2016, 61,679,300 Ordinary Shares were issued for an issue price of £0.38 per Ordinary Share.

3.1.9 On 27 July 2016, 266,700 Ordinary Shares were issued for an issue price of £0.38 per Ordinary Share.

3.2 The Company's authorised and issued fully paid share capital as at the date of this document is, and on First Admission, Second Admission and Re-Admission will be, as follows:

	Present		*Immediately following First Admission*		*Immediately following Second Admission and Re-Admission*[i]	
	Number	*Nominal Value*	*Number*	*Nominal Value*	*Number*	*Nominal Value*
Authorised	274,621,447	£2,746,214.45	302,083,447	£302,083.45	895,722,095	£895,722.00
Issued and fully paid	274,621,447	£2,746,214.45	302,083,447	£302,083.45	895,722,095	£895,722.00

(i) assuming no new Ordinary Shares are issued between Second Admission and Re-Admission.

3.3 For the purposes of implementing the Transaction, the following resolutions in connection with the Company's share capital will be proposed at the General Meeting in relation to the share capital of the Company:

3.3.1 The Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Act, in addition to all existing authorities, to exercise all the powers of the Company to allot Ordinary Shares in the Company or grant rights to subscribe for or convert any security into Ordinary Shares in the Company up to an aggregate nominal value of £726,869.65, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked).

3.3.2 Subject to Second Admission, and in addition to the authority granted by sub-paragraph 3.3.1 above, the Directors be and are hereby generally and unconditionally authorised in accordance with section 551 of the Act:

(a) to exercise all the powers of the Company to allot Ordinary Shares and to make offers or agreements to allot Ordinary Shares in the Company or grant rights to subscribe for or to convert any security into Ordinary Shares in the Company up to an aggregate nominal amount of £179,144.42;

(b) to exercise all the powers of the Company to allot equity securities (within the meaning of section 560 of the Act) up to an additional aggregate nominal amount of £295,588.29 provided that this authority may only be used in connection with a rights issue in favour of holders of Ordinary Shares and other persons entitled to participate therein where the equity securities respectively attributable to the interests of all those persons at such record dates as the Directors may determine are proportionate (as nearly as may be practicable) to the respective numbers of equity securities held or deemed to be held by them or are otherwise allotted in accordance with the rights attaching to such equity securities subject to such exclusions or other arrangements as the Directors may consider necessary or expedient to deal with fractional entitlements or legal difficulties under the laws of any territory or the requirements of a regulatory body or stock exchange or by virtue of shares being represented by depositary receipts or any other matter whatsoever,

provided that the authorities in this sub-paragraph 3.3.2 shall expire at the conclusion of the next annual general meeting of the Company after the passing of this resolution or, if earlier, on the date which is 12 months from the date this resolution is passed, except that the Company may before such expiry make an offer or agreement which would or might require equity securities as the case may be to be allotted after such expiry and the Directors may allot equity securities in pursuance of any such offer or agreement as if the authority in question had not expired.

3.3.3 Subject to Second Admission, the Directors be and are hereby generally and unconditionally authorised pursuant to sections 570 and 573 of the Act to make allotments of equity securities (within the meaning of section 560 of the Act) for cash pursuant to the authority conferred by sub-paragraph 3.3.1 as if section 561 of the Act did not apply to any such allotment, such authority to expire after the period of 12 months after the passing of this resolution, save that the Company may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry date and the Directors may allot equity securities in pursuance of such offer or agreement notwithstanding that the power conferred by this resolution had expired.

3.3.4 Subject to Second Admission and in substitution for the authority granted under section 570 of the Act at the annual general meeting of the Company on 22 June 2017, the Directors be and are hereby generally and unconditionally authorised pursuant to sections 570 and 573 of the Act to make allotments of equity securities (within the meaning of section 560 of the Act) for cash pursuant to the authority conferred by sub-paragraph 3.3.2 above as if section 561 of the Act did not apply to any such allotment provided that such power shall be limited to:

(a) the allotment of equity securities in connection with or pursuant to any issue or offer by way of rights or other pre-emptive offer to the holders of Ordinary Shares and other persons entitled to participate therein in proportion (as nearly as practicable) where the equity securities respectively attributable to the interest of all those persons at such record dates as the Directors may determine are proportionate (as nearly as may be practicable to the respective number of equity securities held or deemed to be held by them or are otherwise allotted in accordance with the rights attaching to such equity securities, but subject to such exclusions or other arrangements as the Directors may deem necessary or expedient in relation to legal or practical issues under the laws of, or as a requirement of, any regulatory or stock exchange authority in any jurisdiction or territory or in relation to fractional entitlements; and/or

(b) the allotment (otherwise pursuant to sub-paragraph (a) above) of equity securities up to an aggregate nominal value of £179,144.42 (being 20 per cent. of Further Enlarged Share Capital),

such authority to expire at the conclusion of the Company's next annual general meeting or, if earlier, 12 months from the date this resolution is passed, save that the Company may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry date and the Directors may allot equity securities in pursuance of such offer or agreement notwithstanding that the power conferred by this resolution had expired.

3.4 Subject to Second Admission, the Consideration Shares will be issued.

3.5 The Ordinary Shares in issue on First Admission and Second Admission are capable of being held in either registered or uncertificated form. In the case of Ordinary Shares held in uncertificated form, the Articles permit the holding and transfer of Ordinary Shares through CREST. CREST is a paperless settlement procedure enabling securities to be evidenced otherwise than by written instrument. The Directors have applied for the Placing Shares to be admitted to CREST. The records in respect of Ordinary Shares held in uncertificated form will be maintained by Euroclear UK and Ireland Limited and the Company's registrar, Computershare Investor Services plc (details of whom are set out on page 9). The Warrants shall only be held in registered form.

3.6 The legislation under which the Placing Shares and the Warrants and any Ordinary Shares issued pursuant to the exercise of the Warrants will be issued is the Act and regulations made under the Act.

3.7 The expected issue date of the First Tranche Placing Shares is 28 December 2017. The expected issue date of the Second Tranche Placing Shares and the Warrants will only be following completion of the Exchange Offer or the Scheme of Arrangement. The Exchange Offer is currently expected to commence in early January and will remain open for a period of not less than 20 business days. The Scheme of Arrangement (if required) would currently be expected to complete in April 2018.

3.8 The Ordinary Shares are denominated in Sterling.

3.9 Following the Placing and Second Admission (assuming that all the Placing Shares and the Consideration Shares are allotted), the Existing Ordinary Shares will represent 30.7 per cent. of the Further Enlarged Share Capital.

3.10 Other than the Warrants, and the Savannah Notes (more particularly described in paragraph 9.2.12 of Part 13 of this document), the Company does not have in issue any securities not representing share capital.

3.11 Other than the Warrants, the Company does not hold any treasury shares and no Ordinary Shares or other shares in the Company were held by, or on behalf of, any member of the Group.

3.12 The International Security Identification Number for the Ordinary Shares is GB00BP41S218.

3.13 Save as disclosed in this paragraph 3 and paragraph 4 and other than the Warrants:

3.13.1 there are no convertible securities, exchangeable securities or securities with warrants;

3.13.2 no person has any acquisition rights and or obligations over authorised but unissued capital, and there is no undertaking to increase the capital; and

3.13.3 no capital of the Company or any member of the Group is under option or is agreed, conditionally or unconditionally, to be put under option.

4 Existing Incentive Schemes

4.1 The Company has granted options and awards under a number of share plans. These are detailed below and are as follows:

4.1.1 long term equity incentive plan (**"LTIP"**); and

4.1.2 supplementary share option plan (**"Supplementary Plan"**).

4.2 ***LTIP***

4.2.1 *Introduction*

On 28 November 2014 the Company established a management long-term incentive equity incentive plan. The LTIP is now closed and is not expected to be reopened.

4.2.2 *Type of award*

Under the terms of the existing LTIP, participants subscribe for shares in SP1L, with an entitlement to exchange such shares for Ordinary Shares if the closing middle market quotation of the Ordinary Shares on any day equals or exceeds £1.68 (the **"Hurdle Price"**).

4.2.3 *Performance conditions and vesting of awards*

(a) The number of Ordinary shares that can be acquired by participants following the Hurdle Price being achieved will be determined on the date of the share exchange in accordance with the following formula:

$X = A - ((A \times B)/C)$

Where:

- X is the number of Ordinary Shares to be issued on exchange (rounded to the nearest whole number);
- A is the number of SP1L shares being exchanged;
- B is £0.56 (being the price at which the Ordinary Shares were admitted to dealing on AIM at the time of the Company's admission to AIM); and
- C is the closing middle market quotation of the Ordinary Shares on the date of the share exchange.

(b) The awards issued pursuant to the LTIP are subject to a vesting date determined for each award. If the Hurdle Price is met after the vesting date, the award will vest when the Hurdle Price is met and the relevant participant can then elect to exchange his or her SP1L shares for the relevant number of Ordinary Shares at any time thereafter.

(c) If the Hurdle Price is met prior to the vesting date, the award will not vest until the vesting date and the relevant participants will not be able to exchange their SP1L shares for Ordinary Shares until after the vesting date unless there is a change of control of the Company, or the individual ceases to be an employee or director of a member of the Group.

4.2.4 *Cessation of employment*

(a) Awards issued pursuant to the LTIP will be subject to full or partial forfeiture if the relevant participant ceases to be either: (i) employed by a member of the Group; or (ii) a director of a member of the Group prior to the vesting date (a **"Leaver"**) (other than awards held by Andrew Knott, which are not subject to any forfeiture provisions).

(b) Pursuant to the terms of the forfeiture provisions, the relevant participant will be required to transfer the following proportion of his or her awards for nil consideration to the Company or a person nominated by the Company:

(i) 100 per cent. if the participant becomes a Leaver within 2.5 years of being issued the awards;

(ii) 0 per cent. if the participant becomes a Leaver after five years of being issued the awards; and

(iii) if the participant becomes a Leaver at or after 2.5 years of being issued the awards but before the fifth anniversary of the awards being issued, the proportion will be determined by the following formula: 50 – 50((Y-2.5)/2.5), where Y is the number of years that have elapsed between the awards being issued and the participant becoming a Leaver.

4.2.5 *Share capital limit*

The number of Ordinary Shares that may be issued pursuant to the LTIP from time to time cannot, in aggregate, exceed 15 per cent. of the Company's fully diluted ordinary share capital from time to time.

4.3 ***Supplementary Plan***

4.3.1 On 30 July 2015, the Company established a supplementary share option plan. The Supplementary Plan is now closed and is not expected to be reopened.

4.3.2 The Supplementary Plan has been implemented and structured principally on the same terms as the LTIP, subject to the following differences:

(a) the aggregate number of any issued or unissued Ordinary Shares being the subject of such schemes from time to time shall not exceed 15 per cent. of the Company's fully diluted share capital;

(b) one half of the equity available under the Supplementary Plan and the LTIP shall be awarded to Andrew Knott;

(c) the share price hurdle rate is three times that of the share option exercise price, which, for the purposes of the issue of share options under the Supplementary Plan is £0.38 per Ordinary Share;

(d) options granted pursuant to the Supplementary Plan will vest and become exercisable on the earliest to occur of: (i) the Company's share price on any day equalling or exceeding £1.14 per Ordinary Share; (ii) any person or group of persons acting in concert obtaining control of 30 per cent. or more of the Company's issued share capital (other than the existing concert party); (iii) the sale of a substantial proportion of the Group's assets (as shall be determined by the Company's Remuneration and Nomination Committee in its sole discretion; and (iv) the passing of a resolution for the voluntary winding up of the Company;

(e) options granted pursuant to the Supplementary Plan will be granted over unissued Ordinary Shares, rather than shares in SP1L; and

(f) options granted pursuant to the Supplementary Plan will lapse in the event that a participant ceases to be either: (i) employed by a member of the Group; or (ii) a director of a member of the Group prior to 28 November 2017.

4.4 ***Awards***

4.4.1 As at the date of this document, the following awards (under the LTIP and the Supplementary Plan collectively) have been granted over: (i) 15,737,896 ordinary shares in the capital of SP1L; and (ii) 10,654,914 Ordinary Shares (equal to approximately 3.9 per cent. of the Existing Ordinary Shares, or 1.2 per cent. of the Further Enlarged Share Capital:

	Share options over shares in SP1L issued pursuant to LTIP	*Share options over Ordinary Shares issued pursuant to Supplementary Plan*
Directors		
Andrew Knott	11,588,574	5,446,630
Isatou Semega-Janneh	446,429	358,786
David Jamison	273,883	128,725
Mark Iannotti	547,765	2,257,450
Stephen Jenkins	1,785,714	1,019,501
Senior management		
Phil Magor	273,883	128,725
Yacine Wafy	547,765	257,450
Jessica Hostage	273,883	531,332
Antoine Richard	–	526,315
Total	15,737,896	10,654,914

5 Articles of Association

The Articles provide, amongst other things:

5.1 ***Voting rights***

Subject to any special rights or restrictions as to voting for the time being attached to any shares, at a general meeting of the Company every member who is present in person (including any corporation present by its duly authorised representative) shall on a show of hands have one vote and every member present in person or by proxy shall on a poll have one vote for each share of which he is a holder. The Directors may accept the appointment of a proxy contained in an electronic communication subject to such terms and conditions as the Directors may determine. In the case of joint holders, the vote of the senior who tenders a vote, whether in person or by proxy, shall be accepted to the exclusion of the votes of the other joint holders.

5.2 ***Restrictions on voting***

Unless the Board determines otherwise, no member is entitled to vote at a general meeting, either in person or by proxy, or to exercise any privilege as a member, or be reckoned in a quorum, in respect of any share held by him unless all calls presently payable by him in respect of that share, whether alone or jointly with any other person, together with interest and expenses (if any) have been paid to the Company.

5.3 ***Dividends***

5.3.1 Subject to the provisions of the Act and of the Articles, the Company may by ordinary resolution declare dividends to be paid to members according to their respective rights and interests in the profits of the Company. However, no dividend shall exceed the amount recommended by the Board and no dividend shall be payable except out of the profits of the Company available for distribution.

5.3.2 Subject to the provisions of the Act, the Board may declare and pay such interim dividends (including any dividend payable at a fixed rate) as appear to the Directors to be justified by the profits of the Company available for distribution.

5.3.3 Except as otherwise provided by the rights attached to shares, all dividends:

(a) shall be declared and paid according to the amounts paid up (otherwise than in advance of calls) on the shares on which the dividend is paid;

(b) shall be apportioned and paid proportionately to the amounts paid up on the shares during any portion or portions on the period in respect of which the dividend is paid, but if any share is issued on terms that it shall rank for dividend as from a particular date, it shall rank for dividend accordingly; and

(c) may be declared in any currency.

5.3.4 All dividends unclaimed for a period of 12 years after having been declared or become due for payment shall (if the Directors so resolve) be forfeited and shall cease to remain owing by the Company.

5.3.5 The Board may, with the authority of an ordinary resolution of the Company, or in the case of an interim dividend may without the authority of an ordinary resolution, direct that payment of any dividend declared may be satisfied wholly or partly by the distribution of assets, and in particular of paid up shares or debentures of any other company, or in any one or more of such ways.

5.3.6 The Board may deduct from any dividend or other moneys payable to any person on or in respect of a share, all such sums as may be due to the Company on account of calls or otherwise in relation to the shares of the Company from him.

5.4 ***Distribution of assets on a winding up***

If the Company is wound up, the surplus assets remaining after payment of all creditors shall be divided among the members in proportion to the capital held by them respectively and, if the surplus assets are insufficient to repay the whole of the capital, the losses shall be borne by the members in proportion to the capital held. If the Company is wound up, the liquidator may, with the sanction of a special resolution of the Company and any other sanction required by law, divide among the members in specie the whole or any part of the assets of the Company. The resolution may provide for and sanction a distribution of any specific assets amongst different classes of members otherwise than in accordance with their existing right. In such an event, every member shall have the right of dissent.

5.5 ***Transfers of shares***

5.5.1 Every member may transfer all or any of his shares which are in certificated form by instrument of transfer in writing in any usual form or in any form approved by the Board, left at the registered office of the Company (or such other place as the Board may determine) and accompanied (except in the case of a transfer by a person to whom the Company is not required by law to issue a certificate and to whom a certificate has not been issued or in the case of a renunciation) by the certificate of the shares to which it relates and such other evidence as the Board may reasonably require to prove the title of the transferor (or person renouncing) and the due execution of the transfer or renunciation by him or, if the transfer or renunciations is executed by some other person on his behalf, the authority of that person to do so. The transferor is deemed to remain the holder of the shares concerned until the name of the transferee is entered in the register of members.

5.5.2 Unless the Directors otherwise determine, a transfer of shares will not be registered if the transferor or any other person appearing to be interested in the transferor's shares has been duly served with a notice under section 793 of the Act, has failed to supply the information required by such notice within 14 days and the shares in respect of which such notice has been served represent at least 0.25 per cent. of their class, unless the member is not himself in default as regards supplying the information required and proves to the satisfaction of the Directors that no person in default as regards supplying such information is interested in any of the shares the subject of the transfer, or unless such transfer is by way of acceptance of a takeover offer, in consequence of a sale on a recognised stock exchange or a sale to an unconnected party.

5.6 ***Variations of rights***

5.6.1 If at any time the share capital of the Company is divided into shares of different classes, any of the rights for the time being attached to any share or class of shares in the Company may be varied or abrogated in such manner (if any) as may be provided by such rights or, in the absence of any such provision, with the consent of the holders of not less than three-quarters in nominal value of the issued shares of the class sanctioning the resolution at a general meeting of the holders of shares of the class. The quorum at any such meeting shall be not less than two persons holding or representing by proxy at least one-third of the nominal amount paid up on the issued shares of the class in question and at an adjourned meeting not less than one person holding shares of the class in question or his proxy.

5.6.2 Subject to the terms of issue of or rights attached to any shares, the rights or privileges attached to any class of shares shall be deemed not to be varied or abrogated by the creation or issue of any new shares ranking *pari passu* in all respects.

5.7 ***Changes in capital***

Subject to the provisions of the Act, the Company in general meeting may from time to time by ordinary resolution increase its share capital, consolidate and divide all or any of its share capital into shares of a larger amount, cancel any shares which at the date of the passing of the resolution have not been taken or agreed to be taken by any person and diminish the amount of its share capital by the amount of the shares so cancelled and sub-divide all or any of its shares into shares of smaller amount. The Company may also, subject to the provisions of the Act and to any rights for the time being attached to any shares, purchase its own shares and, by special resolution, reduce its share capital or any capital redemption reserve fund or any share premium account in any way.

5.8 ***Issues of shares***

5.8.1 Subject to the Act and to any relevant authority of the Company in general meeting required by the Act, the Board may offer, allot (with or without conferring rights of renunciation), grant options over or otherwise deal with or dispose of shares or grant rights to subscribe for or convert any security into shares to such persons, at such times and upon such terms as the Board may decide. No share may be issued at a discount.

5.8.2 Subject to the Act, the Company may at any time pass an ordinary resolution permitting the Directors to generally and unconditionally allot ordinary shares for a period of up to five years from the passing of the ordinary resolution.

5.9 ***Remuneration of Directors***

5.9.1 The salary or remuneration of any Director appointed to hold any employment or executive office in accordance with the Articles may be either a fixed sum of money, or may altogether or in part be governed by business done or profits made or otherwise determined by the Board, and may be in addition to or in lieu of any fee payable to him for his service as Director in accordance with the Articles.

5.9.2 If by arrangement with the Board any Director shall perform or render any special duties or services outside his ordinary duties as a Director and not in his capacity as a holder of employment or executive office, he may be paid such reasonable additional remuneration (whether by way of salary, commission, participation in profits or otherwise) as the Board may determine.

5.10 ***Pensions and gratuities for Directors***

The Board may exercise all the powers of the Company to provide pensions or other retirement or superannuation benefits and to provide death or availability benefits or other allowances or gratuities (whether by insurance or otherwise) for any person who is or has at any time been a Director of the Company or any company which is a holding company or a subsidiary undertaking of or allied to or allocated with the Company or any such holding company or subsidiary undertaking or any predecessor in business of the Company or of any such holding company or subsidiary undertaking, and for any member of his family (including a spouse or former spouse) and any person who is or was dependant on him.

5.11 ***Directors' interests in contracts***

Subject to the Act and provided he has declared the nature and extent of his interest in accordance with the requirements of the Act, a Director who is in any way, whether directly or indirectly, interested in an existing or proposed transaction or arrangement with the Company may:

5.11.1 be a party to, or otherwise interested in, any transaction or arrangement with the Company or in which the Company is otherwise (directly or indirectly) interested;

5.11.2 act by himself or through his firm in a professional capacity for the Company (otherwise than as auditor) and he or his firm shall be entitled to remuneration for professional services as if he were not a Director;

5.11.3 be or become a director or other officer of, or employed by, or a party to a transaction or arrangement with, or otherwise interested in, any body corporate in which the Company is otherwise (directly or indirectly) interested; or

5.11.4 hold any office or place of profit with the Company (except as auditor) in conjunction with his office of Director for such period and upon such terms, including as to remuneration as the Board may decide.

5.12 ***Restrictions on Directors' voting***

5.12.1 Save as provided in the Articles, a Director shall not vote on, or be counted in the quorum in relation to, any resolution of the Directors or of a committee of the Directors concerning any contract, arrangement, transaction or any other proposal whatsoever to which the Company is or is to be a party and in which he has an interest which is to his knowledge a material interest otherwise than by virtue of his interests in shares or debentures or other securities of or otherwise in or through the Company, unless the resolution concerns any of the following matters:

(a) the giving by him of any security, guarantee or indemnity for any money or any liability which he, or any other person, has lent or obligations he or any other person has undertaken at the request, or for the benefit, of the Company or any of its Subsidiary undertakings;

(b) the giving of any security, guarantee or indemnity to any person for a debt or obligation which is owed by the Company or any of its subsidiary undertakings, to that other person if the Director has taken responsibility for some or all of that debt or obligation;

(c) a proposal or contract relating to an offer of any shares or debentures or other securities for subscription or purchase by the Company or any of its subsidiary undertakings, if the Director takes part because he is a holder of shares, debentures or other securities, or if the takes part in the underwriting or sub-underwriting of the offer;

(d) any arrangement for the benefit of employees of the Company or any of its Subsidiary undertakings which only gives him benefits which are also generally given to employees to whom the arrangement relates;

(e) any arrangement involving any other company in the Director (together with any person connected with the Director) has any interest of any kind in that Company (including an interest by holding any position in that company or by being a shareholder of that company;

(f) a contract relating to insurance which the Company can buy or renew for the benefit of the Directors or a group of people which includes Directors; or

(g) a contract relating to a pension, superannuation or similar scheme or a retirement, death, disability benefits scheme or employees' share scheme which gives the Director benefits which are also generally given to the employees to whom the scheme relates.

5.12.2 The Board may authorise, to the fullest extent permitted by law any matter which would otherwise result in a Director infringing his duty to avoid a situation in which he has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the interest of the Company, provided that the Director in question, and any other interested Director, are not counted in the quorum at any board meeting at which such matter is authorised.

5.13 ***Number of Directors***

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

5.14 ***Directors' appointment and retirement***

5.14.1 Directors may be appointed by the Company by ordinary resolution or by the Board. If appointed by the Board, a Director holds office only until the next annual general meeting and shall retire from office but shall be eligible for re-appointment. Each Director shall retire from office at the third annual general meeting after the annual general meeting or general meeting (as the case may be) at which he was previously appointed. A director shall not be required to hold any shares in the Company.

5.14.2 If: (i) at the annual general meeting in any year any resolution or resolutions for the appointment or re-appointment of the persons eligible for appointment or re-appointment of the persons eligible for appointment or re-appointment as Directors are put to the meeting and lost; and (ii) at the end of that meeting the number of Directors is fewer than any minimum number of Directors required, all retiring Directors who stood for re-appointment at that meeting shall be deemed to have been re-appointed as Directors and shall remain in office, but may only act for the purpose of convening general meetings of the Company and perform such duties as are essential to maintain the Company as a going concern, and not for any other purpose.

5.14.3 In addition to any power of removal conferred by the Act, the office of Director shall be vacated if he is requested to resign by all of the other Directors by notice in writing.

5.15 ***Borrowing powers***

The Directors may exercise all the powers of the Company to borrow money and to mortgage or charge all or any part of its undertaking, property and assets (present and future) and uncalled capital and, to create and issue debenture and other securities and give security either outright or as collateral security for any debt, liability or obligation of the Company or any third party. The Board shall restrict the borrowings of the Company, and exercise all voting or powers of control exercisable by the Company in relation to its subsidiary undertakings (if any) so as to secure (but as regards the subsidiary undertakings only so far as by such exercise it can secure) that the aggregate of the amounts borrowed by the Group and remaining outstanding at any time (excluding intra-Group borrowings) shall not without the previous sanction of an ordinary resolution of the Company exceed US$2.5 billion.

5.16 ***Untraced shareholders***

Subject to the Articles, the Company may sell any shares in the Company registered in the name of a member remaining untraced for 12 years who fails to communicate with the Company following advertisement of an intention to make such a disposal. Until the Company can account to the member, the net proceeds of sale will be available for use in the business of the Company or for investment, in either case at the discretion of the Directors. The proceeds will not carry interest.

5.17 ***Meetings***

5.17.1 *Annual General Meetings*

The Company shall comply with the requirements of the Act regarding the holding of an annual general meeting.

5.17.2 *General Meetings*

All general meetings other than annual general meetings shall be called general meetings. General meetings may be called whenever the Board thinks fit or when one has been requisitioned in accordance with the Act.

A general meeting is to be called on at least 14 days' notice in writing exclusive of the day on which it is served or deemed to be served and the day on which the meeting is to be held. A general meeting can be called on shorter notice if a majority in number of the members having a right to attend and vote at the general meeting, being a majority together holding not less than 95 per cent. in nominal value of the shares giving that right, consent. Subject to Section 318(1) of the Act, two members present in person or by proxy and entitled to vote shall be a quorum for all purposes.

5.18 ***Rights attaching to Ordinary Shares***

5.18.1 The Ordinary Shares rank *pari passu* in the following respects:

(a) they are in all respects identical;

(b) they are of the same nominal value and the same amount per Ordinary Share has been paid up;

(c) they carry the same rights as to unrestricted transfer, attendance and voting in general meetings and in all other respects; and

(d) they are entitled to dividends at the same rate and for the same period so that at the next ensuing distribution to the dividend payable on each Ordinary Share will be the same amount.

5.18.2 All of the Existing Ordinary Shares are fully paid and freely transferable.

6 Directors', Senior Managers' and other Interests

6.1 The names of the Directors and Senior Managers of the Company are set out in paragraph 15 of Part 1 of this document.

6.2 The interests (within the meaning of sections 820-825 of the Act) of each Director and Senior Manager and (so far as is known to the Directors and Senior Managers having made all reasonable enquiries) persons connected with them (within the meaning section 252 of the Act) and any member of the Director's and Senior Manager's family (as defined in the AIM Rules) in the issued share capital of Company,

6.2.1 all of which are beneficial (except as noted below) in the issued share capital of the Company as at the Last Practicable Date; and

6.2.2 all of which are beneficial and legal (except as noted below), in the issued share capital of the Company immediately following First Admission, Second Admission and Re-Admission,

in each case, are as follows:

Names	*As at the Last Practicable Date Ordinary Shares*	*%*	*Following First Admission Ordinary Shares*	*%*	*Following Second Admission and Re-Admission(i) Ordinary Shares*	*%*
Directors						
Andrew A Knott[62]	24,204,565	8.81	24,204,565	8.01	26,335,565	2.94
David Jamison[63]	651,009	0.24	651,009	0.22	651,009	0.07
Steve Jenkins	301,800	0.11	301,800	0.10	301,800	0.03
Mark Iannotti	2,793,887	1.02	2,793,887	0.92	2,793,887	0.31
Isatou Janneh-Semega	131,579	0.05	131,579	0.04	131,579	0.01
Stephen O'Brien	–	–	–	–	–	–
Michael Wachtel	–	–	–	–	–	–
David Clarkson	–	–	–	–	–	–
Senior Managers						
Yacine Wafy[64]	965,555	0.35	965,555	0.32	965,555	0.11
Phil Magor	50,000	0.02	50,000	0.02	50,000	0.01
Jessica Hostage	205,776	0.07	205,776	0.07	205,776	0.02
Manish Maheshwari	–	–	–	–	–	–
Chris Thomas	–	–	–	–	–	–
Ian Brown-Peterside	–	–	–	–	–	–

(i) assuming no new Ordinary Shares are issued between Second Admission and Re-Admission.

[62] Held through LCP1, Ariadne Petroleum Limited and LIP, both of which are 100 per cent. beneficially and legally owned by Andrew Knott.

[63] Held through Lowquest Limited, which is 100 percent. beneficially and legally owned by David Jamison.

[64] Held through Rosambo Portfolio S.A., which is 100 percent. beneficially and legally owned by Yacine Wafy.

Related Party Transaction

Andrew Knott is the CEO of the Company and a member of the Board and therefore is regarded as a related party as defined by the AIM Rules. Andrew Knott's participation in the Placing is therefore deemed to be a related party transaction for the purposes of Rule 13 of the AIM Rules. The Directors, other than Andrew Knott, consider, having consulted with Strand Hanson Limited, the Company's nominated adviser, that Andrew Knott's participation in the Placing is fair and reasonable insofar as Shareholders are concerned.

6.3 Save as disclosed in this document, no Director or Senior Manager has any interest in the share capital or loan capital of the Company or any of the subsidiaries of the Company nor does any person connected with the Directors or Senior Managers (within the meaning of section 252 of the Act) have any such interests, whether beneficial or non-beneficial.

6.4 ***Other Interest of Directors in the Group***

Andrew Knott owns legal and beneficial title to one ordinary share in the capital of each of LCP1 and LIP, comprising 100 per cent. of the issued share capital in each of LCP1 and LIP, which as at the Last Practicable Date, together own the legal and voting interest in 24,204,565 Ordinary Shares, being 8.81 per cent. of the Existing Ordinary Shares.

6.5 The Directors and Senior Managers hold or have held the following directorships (in addition to the Company) and/or are or have been a partner in the following partnerships within the five years prior to the date of this document:

Name	*Previous directorships/ memberships*	*Current directorships/ memberships*
Directors		
Andrew Allister Knott	MAN GLG Partners LLP Owlbrook LLP Scotia Oil & Gas LLP Osprey Petroleum Limited Wildcat Petroleum Limited GEP Castle Limited GEP Grey Owl Limited Franklin Petroleum Newfoundland Limited Aigle Resources Limited Aigle Resources Holdings Limited Tafassasset Gold Limited Savannah Petroleum Services Limited Lothian Oil & Gas Partners LLP	Lothian Partners Limited Scotia Oil & Gas Exploration Limited Lothian Capital Partners 1 Limited Savannah Petroleum 1 Limited Ariadne Petroleum Limited Djado Gold Limited Golden Eagle Petroleum Limited Savannah Petroleum 2 Limited Emory Peak Group Holdings LLC

Name	*Previous directorships/ memberships*	*Current directorships/ memberships*
Directors		
Isatou Semega-Janneh	N/A	N/A
David Lawrence Jamison	Hurlingham Polo Association Angus Energy plc	Lowquest Limited D.L.J. Associates (UK) Limited Aquila Energy International Limited Mechcon International (Mechcon Ltd, Nigeria) Energy Development and Investments UK Limited
Stephen ("Steve") Ian Jenkins	Groliffe Limited International Energy Services Limited Franklin Petroleum Newfoundland Limited The UK Oil & Gas Industry Association Limited	Encounter Oil Limited Circle Oil plc Hedgepig Growth Limited Oil & Gas Independents' Association Limited Terrain Energy Limited Postgate Petroleum Limited
Marco ("Mark") Iannotti	FT Energy Advisory Limited	Savannah Petroleum 1 Limited
Sir Stephen O'Brien	City of London Sinfonia Limited Liverpool School of Tropical Medicine Eden Research PLC Aquamarine Transportation Limited Malaria Consortium The Small Business Research Trust Tarmac Leasing Limited Anymix Limited Lafarge Redland Readymix Limited Monier (China) Holdings Limited Cement Direct Limited Redland Readymix Holdings Limited Lafarge International Holdings Limited Tarmac Secretaries (UK) Limited Cannock Recycling Limited Steetley Quarry Products Limited Hereford Recycling Limited Steetley Construction Materials Limited Redland Property Holdings Limited Steetley Properties Limited Redland Engineering Limited Tunnel Building Products Limited Tarmac Directors (UK) Limited Redland Limited	IVCC Observe Limited

Name	*Previous directorships/ memberships*	*Current directorships/ memberships*
Directors		
	Plasterboard Direct Limited Redland Fieldcastle Limited Redland Industrial & Waste Services Limited Cristal Purifiers Limited Steetley Limited Monier (UK) Holdings Limited Monier Technical Centre Limited United Fireclay Products Limited Moore & Sons Limited	
David Clarkson	Bowleven PLC Bowleven New Ventures Limited Bowleven (Kenya) Limited Bowleven Resources Limited Bowleven (Zambia) Limited FirstAfrica Oil Limited Bowleven Cameroon Limited	Adergy Limited
Michael Wachtel	WFW Global LLP Watson Farley & Williams LLP	Clyde & Co LLP
Senior Managers		
Jessica Hostage	N/A	N/A
Manish Maheshwari	N/A	Seven Energy (UK) Limited
Chris Thomas	N/A	Exoro Holding BV Seven Energy (UK) Limited Old Brunswick Investments Limited Old Brunswick Resources Limited
Antoine Richard	N/A	N/A
Ian Brown-Peterside	N/A	N/A
Yacine Wafy	Primo et Geb S.A.R.L.	Rosambo Portfolio S.A.(1) Niger Exploration Limited Niger Exploration 1 Limited
Phil Magor	N/A	N/A

6.6 Subject to paragraph 6.7, no Director or Senior Manager has:

6.6.1 any unspent convictions in relation to indictable offences or convictions in relation to fraudulent offences;

6.6.2 been bankrupt or the subject of an individual voluntary arrangement;

6.6.3 been a director of any company which had a receiver appointed or went into compulsory liquidation, creditors voluntary liquidation, administration or company voluntary arrangement, or made any composition or arrangement with its creditors generally or with any class of its creditors while he was a director or within the 12 months after he had ceased to be a director of that company;

6.6.4 been a partner of any partnership which went into compulsory liquidation, administration or partnership voluntary arrangement, while he was a partner or within the 12 months after he ceased to be a partner in that partnership;

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

6.6.6 had any public criticism by statutory or regulatory authorities (including recognised professional bodies); or

6.6.7 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 any company.

6.7 Steve Jenkins was a director of Circle Oil plc when it was placed into liquidation through a creditors voluntary winding up on 20 February 2017.

6.8 As at the Last Practicable Date, save as set out below, the Company is not aware of any person (other than any Director or Senior Manager) who is directly or indirectly interested in three per cent. or more, of the issued share capital or voting rights of the Company:

6.8.1 the following members own beneficial interests representing three per cent. or more of the Company's issued share capital as at the Last Practicable Date as follows:

Name of member	*Number of Shares*	*Percentage Held*
Standard Life Investments Limited	27,204,000	9.91
Fidelity International Limited	26,841,761	9.77
Andrew Knott[65]	24,204,565	8.81
Capital Group Companies, Inc.	21,968,000	8.00
Legal & General Investment Management Limited	18,160,000	6.61
Petro Ventures SA	17,136,000	6.24
Henderson Global Investors	13,571,502	4.94
Aralia Capital S.A.[66]	11,819,730	4.30
Ludivine Capital Limited	11,444,322	4.17

6.8.2 the following members will own legal and beneficial interests representing three per cent. or more of the Company's issued share capital immediately following First Admission, Second Admission and Re-Admission as follows:

	Following First Admission		*Following Second Admission and Re-Admission[69]*		
Name of member	*Number of Shares*	*Percentage Held*	*Number of Shares*	*Percentage Held*	*Number of Warrants*
Standard Life Investments Limited	29,596,000	9.8%	44,346,000	5.0%	8,571,000
Fidelity International Limited	28,558,761	9.5%	39,144,761	4.4%	6,151,500
Andrew Knott[67]	24,204,565	8.0%	26,335,565	2.9%	1,065,500
Capital Group Companies Inc.	24,164,000	8.0%	66,934,000	7.5%	22,483,000
Legal & General Investment Management Limited	19,555,000	6.5%	28,160,000	3.1%	5,000,000
Petro Ventures SA	17,136,000	5.7%	17,136,000	1.9%	–
Henderson Global Investors	15,001,502	5.0%	42,833,502	4.8%	14,631,000
Aralia Capital S.A.[68]	11,819,730	3.9%	11,819,730	1.3%	–
Ludivine Capital Limited	11,444,322	3.8%	11,444,322	1.3%	–
VR Global Partners L.P.	–	–	97,308,242	10.9%	–
Ashmore Investment Management Limited	–	–	58,576,117	6.5%	–
Miton Asset Management Limited	5,980,000	2.0%	42,857,000	4.8%	21,428,500
International Finance Corporation	–	–	38,972,955	4.4%	–

[65] Held through LCP1 and LIP, both of which are 100 per cent. beneficially and legally owned by Andrew Knott.

[66] Includes the holding of Peleng Holding Corporation, which is wholly owned by the same investor as Aralia Capital S.A.

[67] Held through LCP1, Ariadne Petroleum Limited and LIP, both of which are 100 per cent. beneficially and legally owned by Andrew Knott.

[68] Includes the holding of Peleng Holding Corporation, which is wholly owned by the same investor as Aralia Capital S.A.

[69] Assuming no new Ordinary Shares are issued between Second Admission and Re-Admission.

6.9 As at the Last Practicable Date, so far as the Directors are aware, no person, directly or indirectly, jointly or severally, exercises or could exercise control over the Company.

6.10 As at the Last Practicable Date, so far as the Directors are aware, there are no arrangements the operation of which may at a later date result in a change of control of the Company.

6.11 None of the Company's major holders of Ordinary Shares listed in paragraph 6.8 has voting rights which are different from other holders of Ordinary Shares.

6.12 There are no loans made or guarantees granted or provided by any member of the Group to or for the benefit of any Director or Senior Manager.

6.13 In respect of the Directors and Senior Managers, there are no potential conflicts of interest between any duties they have to the Company and their private interests and/or other duties they may have.

6.14 No Director or any member of his immediate family nor any person connected with him (within the meaning of section 252 of the Act) has a related financial product (as defined in the AIM Rules for Companies) referenced to Ordinary Shares.

7 Directors' and Senior Managers' service contracts and remuneration

The services of the Directors and Senior Managers are provided to the Group under the following agreements:

7.1 *Executive Directors*

7.1.1 *Andrew Knott*

Andrew Knott became a director of the Company on its incorporation on 3 July 2014 and entered into a service agreement with the Company effective from 1 August 2014. Mr Knott is appointed as Chief Executive Officer. The service agreement shall continue until terminated by the Company on 12 months' written notice, such notice not to expire any earlier than 22 December 2019. Under the terms of the agreement, Mr Knott is entitled to an annual salary of £400,000, which will be payable on a monthly basis and, at the sole discretion of the Company's remuneration committee, a bonus of up to three times his annual salary. Mr Knott will also be eligible to participate in any management incentive programme that the Group may adopt. Mr Knott will receive an employer's pension contribution equal to 10 per cent. of his annual salary. There is a right to place Mr Knott on gardening leave during all or any part of his notice period. The service agreement provides for early termination, *inter alia*, in the event of a serious breach of the agreement. Mr Knott's service agreement will be terminated in the event that Mr Knott ceases to be a Director.

7.1.2 *Isatou Semega-Janneh*

Isatou Semega-Janneh became a director of the Company on 21 December 2017. Isatou has been appointed as the Company's Chief Financial Officer on an interim basis. The service agreement shall continue until terminated by either party on six months' written notice. Under the terms of the agreement, Isatou Semega-Janneh is entitled to an annual salary of £148,500, which will be payable on a monthly basis and, at the sole discretion of the Company's remuneration committee, a bonus of up to 30 per cent. of her annual salary. Isatou Semega-Janneh will also be eligible to participate in any management incentive programme that the Group may adopt. The service agreement provides for early termination, *inter alia*, in the event of a serious breach of the agreement.

7.2 *Non-Executive Directors*

7.2.1 *David Jamison*

On 26 July 2014, Mr Jamison was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Jamison on three months' written notice. Mr Jamison is paid an annual fee of £50,000 payable monthly.

7.2.2 *Steve Jenkins*

On 26 July 2014, Mr Jenkins was appointed as non-executive chairman. The appointment shall continue until terminated by either the Company or Mr Jenkins on three months' written notice. Mr Jenkins is paid an annual fee of £160,000 payable monthly.

7.2.3 *Mark Iannotti*

On 3 July 2014, at incorporation of the Company, Mr Iannotti was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Iannotti on three months' written notice. Mr Iannotti is paid an annual fee of £50,000 payable monthly.

7.2.4 *Stephen O'Brien*

On 21 December 2017, Mr O'Brien was appointed as non-executive vice chairman. The appointment shall continue until terminated by either the Company or Mr O'Brien on three months' written notice. Mr O'Brien is paid an annual fee of £50,000 payable monthly, and shall be entitled to a grant of awards over new Ordinary Shares with an aggregate value of £50,000 (based on the Placing Price).

7.2.5 David Clarkson

On 21 December 2017, Mr Clarkson was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Clarkson on three months' written notice. Mr Clarkson is paid an annual fee of £50,000 payable monthly, and shall be entitled to a grant of awards over new Ordinary Shares with an aggregate value of £50,000 (based on the Placing Price).

7.2.6 *Michael Wachtel*

On 21 December 2017, Mr Wachtel was appointed as a non-executive director. The appointment shall continue until terminated by either the Company or Mr Wachtel on three months' written notice. Mr Wachtel is paid an annual fee of £50,000 payable monthly, and shall be entitled to a grant of awards over new Ordinary Shares with an aggregate value of £50,000 (based on the Placing Price).

7.3 ***Directors' Appointment Details***

Name	*Date of Appointment*	*Date of Expiration of Current Term of Office*
Andrew A Knott	3 July 2014	Company's next AGM
David Jamison	26 July 2014	Company's next AGM
Steve Jenkins	26 July 2014	Company's next AGM
Mark Iannotti	3 July 2014	Company's next AGM
Isatou Semega-Janneh	21 December 2017	Company's next AGM
Stephen O'Brien	21 December 2017	Company's next AGM
David Clarkson	21 December 2017	Company's next AGM
Michael Wachtel	21 December 2017	Company's next AGM

8 Employees

8.1 As at 31 December 2016, the Savannah Group had 22 employees and, as at the date of this document, the Savannah Group has 22 employees.

8.2 As at 31 December 2016, the Seven Group had 173 employees and, as at the date of this document, the Seven Group has 100 employees.

8.3 On Completion, it is anticipated that the Enlarged Group will have 126 employees, based at the following locations:

Location	*Number of employees*
London, England	32
Niamey, Niger	10
Lagos, Nigeria	84

9 Material contracts

The following contracts, not being contracts entered into in the ordinary course of business, have been entered into by the Company or any member of the Group and are or may be material or contain any provision under which any member of the Group has an obligation or entitlement which is material to the Group as at the date of this document:

9.1 *Material contracts relating to the Transaction*

A summary of each of the material contracts to be entered into in connection with the Transaction are summarised in Part 14.

9.2 *Material contracts entered into by the Existing Group*

9.2.1 *Placing agreement*

On 22 December 2017, the Company, the Directors, Strand Hanson, Barclays, Mirabaud and Shore Capital entered into the Placing Agreement. Pursuant to the Placing Agreement:

(a) The Company has appointed (i) Strand Hanson as financial and nominated advisor in respect of the Placing; (ii) Barclays as Global Co-ordinator and Joint Bookrunner in respect of the Placing; (iii) Mirabaud as Joint Bookrunner in respect of the Placing; (iv) Shore Capital as Lead Manager in respect of the Placing; and (v) each of the Agents as its placing agent for the purposes of carrying out the Placing of the Placing Shares and the Warrants on the terms of the Placing Agreement.

(b) Subject to certain conditions that are typical for an agreement of this nature, the Company has agreed to allot and issue the Placing Shares and the Warrants at the Placing Price to subscribers procured by the Agents.

(c) The Agents have severally agreed, subject to certain conditions, as agents for the Company to use their respective reasonable endeavours to procure subscribers for the Placing Shares and the Warrants at the Placing Price.

(d) The Company has agreed to pay to the Agents' commissions based on aggregate gross proceeds from the sale of Placing Shares to Placees procured by the Agents. In addition, the Company may, in its sole discretion, elect to pay to the Agents additional discretionary fees.

(e) The obligations of the Agents to use reasonable endeavours to procure subscribers for the Placing Shares and the Warrants on the terms of the Placing Agreement are subject to certain customary conditions. These conditions include there being no breach of any of the warranties given in the Placing Agreement prior to the relevant admission date, there not having been a material adverse change prior to the relevant admission date, admission occurring on or before 8.00 a.m. on 28 December 2017 (in the case of the First Tranche Placing Shares) and by no later than 8.00 a.m. on 30 April 2018 (in the case of the Second Tranche Placing Shares and the Consideration Shares) (or, in each case, such later time and/or date as the Company, Barclays and Strand Hanson may agree) and either the Exchange Offer or the Scheme of Arrangement having completed in accordance with their respective terms. The Placing of the First Tranche Placing Shares is not conditional on the Placing of the Second Tranche Placing Shares.

(f) In addition, Barclays and Strand Hanson have the right to terminate the Placing Agreement, exercisable in certain circumstances, in relation to the Placing Shares and the Warrants at any time prior to admission of the First Tranche Placing Shares and admission of the Second Tranche Placing Shares.

(g) The Company and the Directors have given certain representations, warranties and undertakings to Strand Hanson, Barclays, Mirabaud and Shore Capital. The liability of the Company under the Placing Agreement is unlimited as to amount and time. The liability of the Directors under the Placing Agreement is limited as to amount and as to time.

(h) The Company has given certain indemnities to Strand Hanson, Barclays, Mirabaud and Shore Capital and their respective affiliates.

(i) The parties to the Placing Agreement have given certain representations, warranties and undertakings regarding compliance with certain laws and regulations affecting the making of the Placing in relevant jurisdictions.

(j) The Company has agreed to certain lock-in arrangements, which are described in paragraph 22 of Part 1 of this document.

The Placing is not underwritten.

9.2.2 *Financial adviser appointments*

(a) On 5 June 2017, the Company appointed PJT Partners (UK) Limited (**"PJT"**) as its financial adviser in relation to the Company's investment in and the restructuring of Seven Energy, pursuant to which PJT will provide financial advisory services to the Company including, amongst other things, analysing a range of acquisition, restructuring, refinancing and recapitalisation scenarios.

(b) On 10 January 2017, the Company appointed Hannam & Partners as its financial adviser in relation to certain potential oil and gas transactions, pursuant to which Hannam & Partners will provide financial advisory services in connection with the structuring, timetabling, co-ordinating and completion for any such transaction. Pursuant to the engagement letter with H&P, the Company has agreed to pay to H&P a monthly retainer fee and an additional fee for any successful transaction. Side letters were subsequently entered into on 22 February 2017 and 10 October 2017, pursuant to which H&P agreed also to provide financial advisory services in respect of the Company's potential acquisition of the assets of Seven Energy.

(c) On 4 December 2017, the Company appointed Hannam & Partners as its Joint Corporate Broker and Financial Adviser. The Company has agreed to pay H&P an annual retainer fee in respect of its services.

(d) On 6 November 2017, the Company appointed EAS Advisors, LLC, through Odeon Capital Group LLC ("**Odeon**") to act as its non exclusive placement agent with regard to the Placing. The Company has agreed to pay a cash commission to Odeon in connection with funds introduced to the Placing by Odeon.

9.2.3 *LOGP Services Agreement*

LOGP, which was previously a related party of the Company, provides the Group with administrative, financial and accounting services, in exchange for which the Company pays to LOGP a monthly cost-based fee of £20,000 plus VAT.

9.2.4 *IP Licence Agreement*

The Company has received from Andrew Knott (the "**Licensor**") a non-exclusive, royalty free, transferable, perpetual world-wide right and license, with the right to sublicense (including to members of the Group), in all intellectual property rights in and relating to "Savannah" and such other intellectual property rights as the Licensor may deliver to the Company (the "**IPR**"), including the domain name http://www.savannah-petroleum.com. The license terminates only upon the Company materially breaching the agreement (and leaving such breach unremedied for 30 days), becoming insolvent, or undergoing a change in control. The Company may not use the licensed IPR for any purpose other than in connection with oil and gas exploration and production activities. Other than the initial consideration of £1, paid to obtain the license, there is no fee payable to the Licensor in respect of the license other than to reimburse such costs (eg. trademark fees) as the Licensor may incur in connection therewith. In the event a sub-licensor misuses the licensed IPR, the Company indemnifies the Licensor for any losses suffered thereby.

9.2.5 *R1/R2 PSC*

On 3 July 2014, Savannah Niger entered into a production sharing contract with the Government of Niger represented by the Ministry of Energy and Petroleum for the R1/R2 license area, pursuant to which Savannah Niger paid a US$36,720,000 signature bonus to the State of Niger ($34,000,000) and their advisers ($2,720,000). The minimum work programme, as amended, requires: (i) the acquisition of 500 sq km 3D seismic; and (ii) drilling two wells to a minimum depth of 2,500 metres during the initial period of the exclusive exploration authorisation.

A summary of the key terms of the R1/R2 PSC is set out in Part 15 of this document.

9.2.6 *R3/R4 PSC*

On 30 July 2015, Savannah Niger entered into a production sharing contract with the Government of Niger represented by the Ministry of Energy and Petroleum for the R3/R4 license area, pursuant to which Savannah Niger paid a US$28,000,000 signature bonus to the State of Niger. The minimum work programme requires: (i) the acquisition of 500 sq km 3D seismic; and (ii) drilling two wells to a minimum depth of 2,500 metres during the initial period of the exclusive exploration authorisation.

A summary of the key terms of the R3/R4 PSC is set out in Part 15 of this document.

9.2.7 *Seismic framework contract and call-off order*

On 16 February 2016, Savannah Niger entered into a framework contract with BGP Niger SARL for the provision of 2D and 3D land seismic acquisition services in respect of the R1/R2 and R3/R4 production sharing contract license areas in south east Niger. On 26 July 2016, Savannah Niger entered into a related call-off order, providing for the acquisition of circa 800 sq km of 3D seismic data over part of the Company's R3 license area in south east Niger. The payment obligations under the call-off order are guaranteed by the Company (such guarantee being capped at US$12.5 million). The acquisition completed on 24 January 2017.

9.2.8 *Revolving loan facility*

On 14 December 2016, Savannah Niger entered into a €11,400,000 revolving loan facility with Orabank SA, a West and Central Africa focused banking group. The facility can be drawn and repaid for three years from the date of signature and is available for working capital, potential asset acquisitions and general corporate purposes. An interest rate of 7.5 per cent. is payable on a semi-annual basis on amounts borrowed under the facility.

9.2.9 *Drilling contracts*

On 15 March 2017, the Company signed a letter of award with Great Wall Drilling Company Niger SARL. The letter of award initially related to rig GW89, but was amended to GW215 on 11 April 2017. The letter provides for a programme of three firm wells, and includes options for a further six wells which can be exercised at the Company's discretion. On 8 May 2017, Savannah Niger entered into a formal rig contract with GWDC Niger SARL (**"Great Wall"**) for Rig GW215, along with other contracts for ancillary drilling services including cementing, drilling fluids, fishing services, mudlogging and directional drilling. Under the rig contract, the parties provide a number of reciprocal indemnities including for sickness, injury or death to their own personnel, damage to their own physical property and claims by third parties caused by their own negligence. Savannah Niger also indemnifies Great Wall, *inter alia*, against claims as a result of loss or damage to the well and/or the oil and gas reservoir, pollution other than from Great Wall's equipment and loss or damage, injury sickness or death resulting from a blow-out, crater, catching fire or the well in any manner getting beyond control. If such loss, damage, injury, sickness or death arises out of negligence, breach of duty or failure to observe good operating practice by Great Wall, Great Wall is required to drill the same or an equivalent hole or well to the same depth as the hole had previously been drilled or repair such damaged hole or well to its original state at 50 per cent. of the operating rate. There are no caps on liability under the contract. A similar liability regime exists under each of the contracts for ancillary drilling contracts, except that a cap applies to liability for damage to physical property.

9.2.10 *Lock-up Agreement*

On 14 November 2017, in order to facilitate the Transaction the Company entered into the Lock-up Agreement. A summary of the key provisions of the Lock-up Agreement are set out in paragraph 1.1 of Part 14.

9.2.11 *Liquidity Facility Agreement*

On 12 November 2017, the Company entered into a super senior secured revolving credit facility with, *inter alios*, SEIL and SUGL in order to provide the Seven Group with additional finance for general corporate purposes and working capital requirements in connection with the Transaction. A summary of the key provisions of the liquidity facility agreement are set out in paragraph 1.2 or Part 1.4.

9.2.12 *Loan note issuance*

On 29 November 2017, the Company entered into a loan note instrument to create up to £3,000,000 new unsecured loan notes (the **"Savannah Notes"**). Any Savannah Notes issued are due to be repaid by the Company on or before the six month anniversary of the loan note instrument. No interest is payable on the Savannah Notes. To the extent the Savannah Notes are repaid: (i) on or prior to the three month anniversary of the loan note instrument, a 10 per cent. redemption premium will apply; or (ii) after the three month anniversary of the loan note instrument, a 20 per cent. redemption premium will apply.

9.2.13 *Warrant Instrument*

Pursuant to the Placing, Warrants are being issued to subscribers of Placing Shares on the basis of one Warrant for every two Placing Shares. Set out below are the particulars of the principal terms and conditions applying to the Warrants constituted by an instrument entered into by the Company by way of deed poll dated 21 December 2017 (the "**Warrant Instrument**").

(a) Constitution

The Company has determined by a resolution of the Board to issue 133,231,000 Warrants, each entitling the holder thereof (the "**Warrantholder**") to subscribe for Ordinary Shares at the Placing Price (or such adjusted price as may be determined from time to time in accordance with the provisions of the Warrant Instrument) (the "**Exercise Price**") payable in cash in full on subscription.

The issue of the Warrants is conditional on the admission of the Second Tranche Placing Shares to trading on AIM and such admission becoming effective in accordance with the AIM Rules for Companies ("**Second Tranche Admission**").

(b) Subscription Rights

The Warrantholder of each Warrant will have the right ("**Subscription Rights**"), which may be exercised on any business day from the date of the Warrant Instrument up to (and including) the date falling 12 calendar months after Second Tranche Admission (the "**Expiry Date**"), being the period during which the Warrants may be exercised (the "**Subscription Period**"), to subscribe in cash for one Ordinary Share (subject to adjustment in accordance with the terms of the Warrant Instrument) in consideration of the payment of the Exercise Price in full per Warrant.

Every Warrant in respect of which Subscription Rights:

(i) have been exercised in full; or

(ii) at the end of the Subscription Period have not been exercised,

shall lapse and be cancelled.

Ordinary Shares allotted pursuant to the exercise of Warrants in accordance with the terms of the Warrant Instrument shall be issued fully-paid and free from any liens, charges or encumbrances and rights of pre-emption but shall not rank for any dividends or other distributions declared, made or paid on the Ordinary Shares for which the record date is prior to the date on which the Warrants are exercised (the "**Exercise Date**") but, subject thereto, shall rank in full for all dividends and other distributions declared, made or paid on the Ordinary Shares on or after the Exercise Date and otherwise pari passu in all respects with the Ordinary Shares in issue at that date.

At any time when the Ordinary Shares are admitted to trading on AIM, application will be made by the Company to the London Stock Exchange for the Ordinary Shares allotted pursuant to any exercise of Warrants to be admitted to trading on AIM and the Company will promptly apply for such admission so as to be effective simultaneously with the allotment of the relevant Ordinary Shares pursuant to the exercise of the Warrants in accordance with the terms of the Warrant Instrument becoming effective.

(c) No Transfer

No Warrantholder shall assign, transfer, mortgage, charge, declare a trust over, or deal in any other manner with its Warrants or any of its rights under them.

(d) Undertakings of the Company

The Company shall not in any way modify the rights attaching to the existing Ordinary Shares as a class in any way which operates to vary the rights of the Warrantholders in relation to the Warrants.

Warrantholders will have made available to them, at the same time and in the same manner as the same are made available to holders of Ordinary Shares, copies of the audited accounts of the Company (with the relevant directors' and auditor's reports) and copies of all other circulars or notices which are made available to holders of Ordinary Shares.

(e) Adjustment of Subscription Rights

The Exercise Price shall from time to time be adjusted in accordance with the provisions of the Warrant Instrument to account for any sub-division or consolidation of the Ordinary Shares or reduction of share capital of the Company or any issue of Ordinary Shares fully paid by way of capitalisation of profits or reserves.

Whenever the Exercise Price is adjusted in accordance with the Warrant Instrument (other than by reason of a consolidation of the share capital of the Company as referred to in this paragraph (e)) the number of Ordinary Shares for which a Warrantholder is entitled to subscribe shall be increased accordingly at the same time as such adjustment takes effect.

Whenever the Exercise Price is adjusted in accordance with the Warrant Instrument by reason of a consolidation of the share capital of the Company as referred to in paragraph (e), the number of Ordinary Shares for which a Warrantholder is entitled to subscribe shall be decreased accordingly at the same time as such adjustment takes effect.

(f) Takeovers

If at any time an offer or invitation is made by the Company to the holders of the Ordinary Shares for the purchase by the Company of any of its Ordinary Shares, the Company shall simultaneously give notice thereof to each Warrantholder who shall be entitled, at any time whilst such offer or invitation is open for acceptance, to exercise its Subscription Rights to the extent that such rights have not been exercised or lapsed prior to the record date of such offer or invitation so as to take effect, in so far as is reasonably practicable, as if it had exercised its rights immediately prior to the record date of such offer or invitation.

If at any time an offer is made to all holders of Ordinary Shares (or all holders of Ordinary Shares other than the offeror and/or any company controlled by the offeror and/or persons acting in concert with the offeror) to acquire the whole or any part of the issued share capital of the Company and the Company becomes aware that as a result of such offer the right to cast a majority of the votes which may ordinarily be cast on a poll at a general meeting of the Company has or will become vested in the offeror and/or such persons or companies as aforesaid:

(i) the Company shall give notice to each Warrantholder within ten Business Days of its becoming so aware, and each Warrantholder shall be entitled, subject to paragraph (iii) below, to exercise its Subscription Rights to the extent that such rights have not lapsed or been exercised prior to the record date of such offer;

(ii) the Company shall use reasonable endeavours to procure that a similar offer is made to Warrantholders as if all outstanding Subscription Rights had been exercised immediately before the record date for that offer; and

(iii) to the extent that any Subscription Rights have not been exercised within one month after such offer shall have become or been declared unconditional in all respects they shall lapse.

(g) Winding up

If an effective resolution is passed on or before the last day of the Subscription Period for the voluntary winding-up of the Company (except for the purpose of reconstruction, amalgamation or merger on terms sanctioned by a special resolution of the Warrantholders, in which case the Warrantholder shall be entitled to be granted by the reconstructed, amalgamated or merged company a substituted warrant of the value of the Warrant immediately prior to such reconstruction, amalgamation or merger) then the Company shall forthwith give notice to the Warrantholders stating that such a resolution has been passed.

A Warrantholder shall be entitled at any time within three months after receipt of the notice given pursuant to the paragraph above to elect by notice in writing to the Company's registered office to be treated as if he had, immediately before the date of passing of the winding up resolution, exercised his Warrants and he shall be entitled to receive out of the assets which would otherwise be available in the liquidation to the holders of Ordinary Shares pari passu, such a sum (if any) as he would have received out of the assets which would otherwise be available in the liquidation to the holders of Ordinary Shares had he been the holder of and paid for the Ordinary Shares to which he would have become entitled by virtue of such exercise, after deducting from such sum an amount equal to the moneys which would have been payable by him in respect of such shares if he had exercised his Warrants.

(h) Modification of Rights

Any modification to the Warrant Instrument may be effected only by deed poll executed by the Company with the prior sanction of a special resolution of the Warrantholders.

All or any of the rights for the time being attaching to the Warrants (including the Subscription Rights) may from time to time (whether or not the Company is being wound up) be altered or abrogated with the prior sanction of a special resolution of the Warrantholders.

9.2.14 The Additional Funding Term Sheet

In connection with the Additional Potential Investment, the Company entered into a non-binding term sheet with potential investors including IDB Infrastructure Fund II B.S.C.(c) ("**IDB Fund**"), on 21 December 2017.

In accordance with the provisions of the term sheet:

(a) IDB Fund has agreed in principle to invest US$10 million in the Company in return for 21,312,418 Ordinary Shares at the Placing Price. The Company has also agreed to grant IDB Fund a right to subscribe for up to 42,624,837 Ordinary Shares at the Placing Price. This right will be exercisable by IDB Fund at any time in the two years immediately following the admission to trading on AIM of the First Tranche Placing Shares.

(b) Two other potential investors have each agreed in principle to invest US$10 million in the Company in return for 21,312,418 Ordinary Shares at the Placing Price, subject to appropriate structure being agreed. The Company has also agreed to grant to each of these potential investors a right to subscribe for up to 42,624,837 Ordinary Shares at the Placing Price. This right will be exercisable by each such potential investor at any time in the two years immediately following the admission to trading on AIM of the First Tranche Placing Shares.

Any new Ordinary Shares that are issued to such potential investors will be subject to lock-up provisions that will restrict the transfers of such shares for a period of 6 months without the prior written consent of the Company's nominated adviser and brokers (at the relevant time). These lock-up arrangements will be subject to customary exceptions, including a transfer pursuant to the acceptance of a takeover offer.

Each such potential investor has also agreed, for a period of 24 months, not to exercise its respective voting rights in the Company in such a manner as to seek to: (i) effect changes to the Company's Board (save for where such changes are recommended by the Board); (ii) undermine or frustrate the Company's day-to-day operations; (iii) effect amendments to, or introduce obstacles to the implementation of, the Company's strategy as approved by the Board from time to time; and/or (iv) alter or amend Directors' remuneration.

The transactions contemplated by this term sheet are subject to completion of final due diligence, each potential investor's relevant approval processes and the signature of definitive legal documentation in a form and substance satisfactory to the Company.

9.3 ***Material contracts relating to the Seven Assets***

A summary of each of the material contracts entered into in relation to the Seven Assets are summarised in paragraphs 2 to 5 of Part 14 of this document.

10 Related party transactions

10.1 Save as disclosed in this document, or the related party transaction notes contained in the financial statements incorporated by reference in this document, none of the Directors has any interest, beneficial or non-beneficial, in the share or loan capital of the Company.

10.2 Save as disclosed in this document, or the related party transaction notes contained in the financial statements incorporated by reference in this document, none of the Directors has any interest, direct or indirect, in any assets that have been or are proposed to be acquired or disposed by, or leased to, the Group and no contract or arrangement exists in which any Director is materially interested and which is significant in relation to the business of the Group.

11 Investments

Other than in respect of the Accugas Transaction, there are no investments made, being made by the Company or to be made in the future in respect of which firm commitments have been made.

12 Property

The Company's principal establishment (which is leased and used as an office facility) is located at 40 Bank Street, London, E14 5NR.

13 Working capital

The Company is of the opinion that, after having made due and careful enquiry, the working capital available to the Enlarged Group taking account the proceeds of the Placing is sufficient for its present requirements, that is for at least the next twelve months from the date of Re-Admission.

14 Litigation

14.1 Subject to paragraph 14.2, no member of the Enlarged Group is or has been involved in any governmental, legal or arbitration proceedings and the Company is not aware of any such proceedings pending or threatened by or against the Group during the 12 months preceding the date of this document which may have or have had in the recent past a significant effect on the financial position or profitability of the Group.

14.2 Universal is involved in an action by a local community, who are claiming that they were displaced by Universal's activities. The value of the claim is NGN 100,000,000 (approximately US$ 277,780). The Directors, having taken legal advice, believe such claims lack merit and should be defended.

15 No significant change statement

15.1 Save for the draw down from the €11.4 million revolving loan facility with Oragroup SA by Savannah Niger since 30 June 2017, of €8.8 million as at the date of this document, there has been no significant change in the trading or financial position of the Existing Group since 30 June 2017, the date to which the last interim accounts of the Existing Group were published.

15.2 There has been no significant change in the trading or financial position of the Seven Group since 30 June 2017, the date to which the historical financial information of the Seven Group included in this document were prepared.

16 General

16.1 The total costs and expenses of, or incidental to, the Placing and First Admission, Second Admission and Re-Admission, all of which are payable by the Company, are estimated to be approximately US$12.5 million (exclusive of value added tax). Out of the total fees and expenses of the Transaction payable by the Company, it has been agreed that certain advisers' fees in an aggregate amount of US$14.7 million will be applied in subscribing for Ordinary Shares pursuant to the Placing. The expected net proceeds of the Placing, after deduction of such costs and expenses (excluding value added tax), is US$112.5 million.

16.2 The Competent Person's Report in respect of the Nigerien assets is included, in the form and context in which it is included, with the consent of Robertson (UK) Limited which has authorised the contents of its report for the purposes of the AIM Rules. Robertson (UK) Limited has also given and not withdrawn its written consent to the inclusion of references in this document to its name in the form and context in which they appear.

16.3 The Competent Person's Report in respect of the Nigerian assets is included, in the form and context in which it is included, with the consent of Lloyd's Register Group Limited which has authorised the contents of its report for the purposes of the AIM Rules. Lloyd's Register Group Limited has also given and not withdrawn its written consent to the inclusion of references in this document to its name in the form and context in which they appear.

16.4 KPMG LLP, Chartered Accountants and registered auditors, of 15 Canada Square, Canary Wharf, London E14 5GL, has given and has not withdrawn its consent to the inclusion of its Accountants' report on the historical financial information of the Seven Group in Part 9A of this document in the form and context in which it appears, and has authorised its report for the purposes of Schedule Two of the AIM Rules for Companies.

16.5 Strand Hanson Limited has given and not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear.

16.6 Mirabaud has given and not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear.

16.7 Shore Capital has given and not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear.

16.8 Barclays has given and not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear.

16.9 Hannam & Partners has given and not withdrawn its written consent to the inclusion in this document of references to its name in the form and context in which they appear.

16.10 The accounting reference date of the Company is 31 December.

16.11 It is expected that definitive share certificates will be despatched by hand or first class post by 5 January 2018 for the First Tranche Placing Shares. In respect of uncertificated shares, it is expected that Shareholders' CREST stock accounts will be credited on 28 December 2017 for the First Tranche Placing Shares.

On assumption that acquisition of SSNs is effected through the Exchange Offer, it is expected that definitive certificates in respect of the Second Tranche Placing Shares and the Warrants will be despatched in mid-February 2018 by hand or first class post. In respect of uncertificated shares, it is expected that Shareholders CREST stock accounts will be credited in early February for the Second Tranche Placing Shares.

16.12 Save as disclosed in of this document, the Directors are unaware of any exceptional factors which have influenced the Existing Group's activities.

16.13 Save as disclosed in this document, no person (other than the Company's professional advisers named in this document and trade suppliers) has at any time within the 12 months preceding the date of this document received, directly or indirectly, from the Company or any other member of the Group or entered into any contractual arrangements to receive, directly or indirectly, from the Company or any other member of the Group on or after restoration to trading of the Existing Ordinary Shares any fees, securities in the Company or any other benefit to the value of £10,000 or more.

16.14 The Placing Price of 35 pence represents a premium of 34,900 per cent. above the nominal value of one tenth of a penny per Ordinary Share. The Placing Price is payable in full on application.

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

16.16 Save as disclosed in this document, so far as the Directors are aware there are no environmental issues that may affect the Company's utilisation of its tangible fixed assets.

16.17 The Directors are not aware of any patents or other intellectual property rights, licences, particular contracts or manufacturing processes on which the Group is dependent.

16.18 There are no provisions in the Articles which would have the effect of delaying, deferring or preventing a change of control of the Company.

16.19 Save as disclosed in this document, the Directors are unaware of:

16.19.1 any significant trends in production, sales and inventory and costs and selling prices since 31 December 2016 to the date of this document; and

16.19.2 any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Group's prospects for at least the current financial year.

16.20 The Articles contain no restriction on the objects of the Company.

17 UK taxation

17.1 *General*

These comments are intended only as a general guide to the current tax position in the United Kingdom as at the date of this document. The comments assume that the Ordinary Shares and Warrants are held as an investment and not as an asset of a financial trade and that any dividends paid are not foreign income dividends. If you are in any doubt as to your tax position, or are subject to tax in a jurisdiction other than the United Kingdom, you should consult your professional adviser.

The comments are based on UK tax law and understanding of published HM Revenue and Customs (**"HMRC"**) practice at the date of this document, all of which are subject to change, possibly with retrospective effect. The comments are a general guide only and do not apply to certain categories of Shareholder or Warrantholder, such as persons owning shares and/or Warrants as securities to be realised in the course of a trade, persons owning more than a 10 per cent. stake in the Company, persons who are not resident in the United Kingdom, or are resident but not domiciled in the United Kingdom, or persons who do not acquire their Placing Shares under the Placing.

Certain Shareholders, such as dealers in securities, collective investment schemes, insurance companies and persons acquiring their Ordinary Shares and/or Warrants in connection with their employment or as an office holder may be taxed differently and are not considered. Furthermore, the following paragraphs do not apply to potential investors who intend to acquire Ordinary Shares and/or Warrants as part of tax avoidance arrangements; or persons with special tax treatment such as pension funds, trustees of discretionary trusts or charities. The following is not intended to be, nor should it be considered to be, legal or tax advice to any particular investor. Accordingly, all potential investors are advised to obtain their own professional advice on the tax implications of acquiring, owning and/or disposing of Placing Shares and/or Warrants.

17.2 *Dividends*

Dividends received from the Company by a UK resident individual shareholder will form part of the 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 of taxable dividend income received by the shareholder in a tax year. Where the dividend income is above the £5,000 dividend allowance, the first £5,000 of the dividend income will be charged at the nil rate and any excess amount will be taxed at the rate that would apply to that amount if the nil rate did not exist. The rates are 7.5 per cent. to the extent that the excess amount falls within the basic rate tax band, 32.5 per cent. to the extent that the excess falls within the higher rate tax band and 38.1 per cent. to the extent that the excess amount falls within the additional rate tax band.

The UK government announced on 8 March 2017 that it intends to reduce the dividend allowance from £5,000 to £2,000 from April 2018.

UK resident corporate shareholders will not generally be subject to tax on dividends received by the Company as long as the dividends fell within an exemption and certain other conditions are met. Examples of dividends that fall within an exemption are dividends paid on ordinary shares for UK tax purposes which are not redeemable (it is noted that the Ordinary Shares should for these purposes constitute such ordinary shares) as well as dividends paid to a company holding less than 10 per cent. of the issued share capital of the payer.

Non-UK resident individual shareholders, other than on the dividends representing the receipts of a trade, profession or vocation carried on in the UK, are taxed on dividends arising from a UK source. The tax liability is however limited to the sum of tax deducted from, or treated as deducted from, "disregarded income" (as defined by statute and which includes dividends from UK resident companies) and the tax liability leaving out the disregarded income and with no personal allowances or double taxation relief taken into account. Where the limitation applies, shareholders should have no further UK income tax to pay upon their receipt of a dividend from the Company. Shareholders may also be subject to foreign taxation on dividend income under applicable local law.

17.3 ***Capital Gains***

A disposal of Placing Shares or Warrants by a Shareholder or Warrantholder resident or, in the case of an individual, ordinarily resident for UK tax purposes in the United Kingdom may, depending on the Shareholder's or Warrantholder's circumstances and subject to any available exemptions, allowances or reliefs (such as entrepreneurs relief), give rise to a chargeable gain or an allowable loss for the purposes of UK taxation of chargeable gains.

To the extent that a Shareholder acquires Placing Shares pursuant to the Placing, such Placing Shares so allotted will, for the purpose of tax on chargeable gains, be treated as acquired on the date of the Placing. The amount paid for the Placing Shares will generally constitute the base cost of a Shareholder's holding.

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

In the absence of any available allowances and reliefs, again arising on the disposal of Ordinary Shares or Warrants by a UK resident Individual Shareholder will be taxed at a rate of 10 per cent. except to the extent that the gain (calculated in Sterling), when it is added to the Shareholder's other taxable income in excess of the personal allowance and other gains in the relevant tax year, exceeds the upper limit of the basic rate income tax band (£45,000 for the tax year ending 5 April 2018), in which case it will be taxed at the rate of 20 per cent. The capital gains tax annual exemption (£11,300 for the tax year ending 5 April 2018) may be available to an individual shareholder to offset against chargeable gains realised on the disposal of Ordinary Shares or Warrants.

For a Shareholder which is a UK resident company, any gain on the disposal of its Ordinary Shares or Warrants will be subject to corporation tax (19 per cent. for the tax year ending 31 March 2018) in the absence of any available exemptions and reliefs.

Subject to the below, shareholders who are not resident in the UK for tax purposes will not generally be subject to UK tax on chargeable gains, unless they carry on a trade, profession or vocation in the UK through a branch or agency or (in the case of a company) permanent establishment and the Ordinary Shares or Warrants disposed of are used or held for the purposes of that branch, agency or permanent establishment.

A shareholder who is an individual, who has ceased to be resident for tax purposes in the United Kingdom for a period of less than five years who disposes of Ordinary Shares or Warrants during that period may be liable to UK taxation on capital gains (in the absence of any available exemptions or reliefs). If applicable, the tax charge will arise in the tax year that the individual returns to the United Kingdom.

17.4 ***Stamp duty and stamp duty reserve tax***

No stamp duty or SDRT should be payable on the issue of Ordinary Shares (whether in certificated form outside of CREST or credited in uncertificated form to an account in CREST).

On the basis that the Ordinary Shares are admitted to trading on AIM but not listed on that or any other market subsequent dealings in Ordinary Shares should not be subject to stamp duty or SDRT. Otherwise, transfers of Ordinary Shares and Warrants for value will generally give rise to a liability to pay UK *ad valorem* stamp duty or SDRT at a rate of 0.5 per cent. of the amount or value of the consideration (rounded up in the case of stamp duty to the nearest £5).

The above statements are intended to be a general guide to the current stamp duty and SDRT position and apply regardless of whether or not a Shareholder is resident in the UK for UK tax purposes.

18 Mandatory bids, squeeze out and sell-out rules relating to the Ordinary Shares

18.1 ***Mandatory bid***

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

18.2 ***Squeeze-out***

Under the Act, if an offeror were to acquire 90 per cent. of the Ordinary Shares within four months of making its offer, it could then compulsorily acquire the remaining 10 per cent. It would do so by sending a notice to outstanding Shareholders telling them that it will compulsorily acquire their shares and then, six weeks later, it would execute a transfer of the outstanding shares in its favour and pay the consideration to the Company, which would hold the consideration on trust for outstanding Shareholders. The consideration offered to the Shareholders whose shares are compulsorily acquired under the Act must, in general, be the same as the consideration that was available under the takeover offer.

18.3 ***Sell-out***

The Act also gives minority Shareholders in the Company a right to be bought out in certain circumstances by an offeror who had made a takeover offer. If a takeover offer related to all the 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 per cent. of the Ordinary Shares, any holder of shares to which the offer relates who has not accepted the offer can by a written communication to the offeror require it to acquire those shares. The offeror would be 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. If a Shareholder exercises its rights, the offeror is bound to acquire those shares on the terms of the offer or on such other terms as may be agreed.

19 Documents available for inspection

Copies of the following documents will be available for inspection during usual business hours on any day (Saturdays, Sundays and public holidays excepted) at the offices of Computershare Investor Services plc at the Pavilions, Bridgwater Road, Bristol, BS13 8AE for a period of a month from the date of this document:

19.1 the memorandum and articles of association of the Company; and

19.2 the Accountant's Report on the Historical Financial Information of the Seven Group from KPMG LLP set out in Part 9(A) of this document.

20 Copies of this document

Copies of this document will be available to the public free of charge at the offices of Computershare Investor Services plc at the Pavilions, Bridgwater Road, Bristol, BS13 8AE during normal business hours on any weekday (other than Saturdays, Sundays and public holidays), for a period of at least one month from the date of Re-Admission. This document will also be available for download from the Company's website at www.savannah-petroleum.com.

PART 14

MATERIAL CONTRACTS

1 Material contracts relating to the Transaction

1.1 *Lock-up Agreement*

1.1.1 On 14 November 2017, in order to support and facilitate the Transaction, the Company entered into the Lock-up Agreement with, among others, certain key debt holders of SEFL, in particular certain holders of the SSNs, certain lenders under certain of SEFL's bilateral debt facilities and the holder of the 10.50 per cent. Notes, SEIL, SEFL and certain other members of the Seven Energy Group (the "**Locked-up Parties**").

1.1.2 The Locked-up Parties agreed, *inter alia,* to use reasonable endeavours to support, facilitate and implement the Transaction as set out therein, including exercising any voting powers or rights available to the Locked-up Parties in favour of the Transaction and not to accept, solicit or investigate any alternative to the Transaction.

1.1.3 The Lock-up Agreement will remain in force until the earlier to occur of: (i) the date on which the trustee under the indenture in relation to the SSNs accedes to the Implementation Agreement; (ii) the date the Implementation Agreement terminates in accordance with its terms; (iii) the date that any enforcement action is taken by the Company under the liquidity facility referred to below; or (iv) where the Implementation Agreement has not been executed, the long-stop date of 31 January 2018, which can be extended by up to a further two months by agreement with SEIL and the Majority Consenting Parties (as defined in the Lock-Up Agreement), provided that it is not terminated earlier pursuant to the prescribed termination events.

1.1.4 The Lock-up Agreement may be terminated by specific majorities, the Company and/or SEIL in a number of prescribed circumstances including, but not limited to:

(a) if a government body or court restrains the implementation of the Transaction;

(b) if the Company or SEIL are subject to an event which materially impacts their ability to implement the Transaction;

(c) if terms sheets/waivers (in each circumstance including binding lock-up provisions) are not executed within 8 weeks of 14 November 2017 with the holder of the Promissory Note, the lenders under the DSA Facility Agreement and the lenders under the WCF Agreement, who are not party to the Lock-Up Agreement;

(d) if an unplanned insolvency event in respect of certain material Seven Group entities occurs; and

(e) if there is a material adverse change in the consolidated financial position of the companies which the Company is seeking to acquire.

Various grace and cure periods apply to certain termination events contained in the Lock-Up Agreement.

1.1.5 The Company is currently undertaking ongoing discussions to agree the terms of the Amendment Lock-Up Agreement, which reflects the current terms of the Transaction.

1.2 *Lock-Up Amendment Agreement*

On or around 21 December 2017 certain parties to the Lock-Up Agreement entered into a Lock-Up Amendment Agreement. Amongst other things this agreement:

– resized the consideration payable to the SSNs and the Second Bilateral Lender (amounts as set out in Figure 11) of paragraph 2.2 of Part 2 of this document;

- amended the transaction structure to allow the company to purchase the SSNs for the consideration set out herein prior to Completion via an exchange offer or scheme of arrangement (extendable to 31 May in certain circumstances);
- extended the Long-Stop Date to 31 March 2018;
- approved all necessary changes to the steps plan to reflect the new transaction structure.

Pursuant to the Lock-Up Agreement this amendment is approved by Seven Energy, the Company and the Majority Consenting Parties making it binding on all parties to the Lock-Up Agreement. Given the nature of these changes, notwithstanding that the amendment is valid and binding on all Participating SSN Noteholders, the Participating SSN Noteholders who have not signed the Lock-Up Amendment Agreement will have until 5.00 p.m. on the 5 January to withdraw their accession to the Lock-Up Agreement. If Participating SSN Noteholders withdraw their accession to the Lock-Up Agreement it could have an adverse impact on the timing and implementation of the Transaction.

1.3 ***Liquidity Facility Agreement***

1.3.1 On 14 November 2017, the Company entered into a super senior secured revolving credit facility (the "**Liquidity Facility**") with, *inter alios*, SEIL and SUGL in order to provide the Seven Energy Group with additional finance for general corporate and working capital requirements in connection with the Transaction.

1.3.2 The Liquidity Facility provided by the Company to the Seven Energy Group is for an amount of up to US$20 million, to be made available in three tranches as follows:

(a) firstly, US$1.5 million, which was pre-funded to a client account of legal counsel to the Seven Energy Group (and is held subject to an undertaking provided by such legal counsel) and which will be transferred to an account of the Seven Energy Group upon the satisfaction or waiver of all conditions precedent under the Liquidity Facility and which is only permitted to be withdrawn to finance projected costs in connection with any insolvency, liquidation or administration proceedings involving any member of the Seven Energy Group;

(b) secondly, US$3.5 million available upon satisfaction or waiver of all conditions precedent to the Liquidity Facility; and

(c) thirdly, the remaining US$15 million available from signing of the Implementation Agreement (subject to all conditions precedent to the Liquidity Facility having been satisfied or waived).

1.3.3 Any drawings under the Liquidity Facility (other than the $1.5 million that was pre-funded) are subject to the Company's approval unless such payments to be funded by such drawings are pre-agreed. Certain drawings in respect of fees associated with the Transaction have been pre-approved as set out in the relevant schedule to the Liquidity Facility. Currently there remain a number of conditions precedent outstanding under the Liquidity Facility and no drawings have been made by the Seven Group.

1.3.4 Loans under the Liquidity Facility are subject to PIK interest at 6 per cent. per annum and are repayable in full upon completion of the Transaction or, if earlier, on termination of either the Lock-up Agreement or the Implementation Agreement. The Liquidity Facility is secured over certain assets of the Seven Energy Group on a super senior basis pursuant to the terms of an intercreditor agreement dated 10 October 2014 (as amended and/or restated from time to time) between, *inter alios*, SEIL, SEFL and The Law Debenture Trust Corporation P.L.C. The Liquidity Facility contains events of default relating to a failure to comply with undertakings in the Liquidity Facility and related finance documents, misrepresentation and the invalidity or unenforceability of the transaction security or of the guarantee obligations of the Seven Group relating to the Liquidity Facility, subject to certain grace periods and *de minimis* amounts as set out therein.

1.3.5 It is intended that the Liquidity Facility will be used to part fund the advisory and legal fees incurred by the Seven Energy Group as part of the Transaction. The Company intends to fund the first and second tranches of the Liquidity Facility from its existing working capital and undrawn amounts in terms of its existing revolving loan facility with Oragroup SA. The third tranche is expected to be financed from the proceeds of the proposed equity fundraise to take place in connection with the Transaction.

1.3.6 It is intended that upon completion of the Transaction SEIL's obligations under the Liquidity Facility will be assumed by Eight Holdco and that the loan will be amended and restated as a subordinated shareholder loan.

1.4 ***New Accugas Senior Secured Notes***

1.4.1 Pursuant to the terms of the Lock-up Agreement, it has been agreed that holders of the SSNs who elect to subscribe for the SSN Shares will also be entitled to a *pro rata* share of the re-instated US$20 million Accugas Holdco senior secured notes due 2024 (the **"Accugas Senior Secured Notes"**).

1.4.2 Cash interest on the Accugas Senior Secured Notes will accrue on a pay-if-you-can basis at 6 per cent. per annum and paid-in-kind interest will accrue at 8 per cent. per annum. The Accugas Senior Secured Notes will be guaranteed by Accugas Midco and will be secured by share pledges over Accugas Holdco and Accugas Midco, and by all asset security granted by Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) by share security over, or asset security from, Accugas Limited.

1.5 ***Accugas Holdco 10.50 per cent. Holder Notes***

Pursuant to the terms of the Lock-up Agreement, it has been agreed that Accugas Holdco will, upon completion of the Transaction, issue US$15 million of notes due 2026 (payable in NGN at the prevailing NAFEX rate) to the holder of SEFL's 10.50 per cent. senior secured notes due 2021 (the **"Private Bond Accugas Notes"**). The Private Bond Accugas Notes will be secured by share pledges over Accugas Holdco and Accugas Midco, and by all asset security granted by Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) by share security over, or asset security from, Accugas Limited. Cash interest will accrue on a pay-if-you-can basis at 8 per cent. per annum and paid-in-kind interest will accrue at 10 per cent. per annum.

1.6 ***First Bilateral Facility Notes***

Pursuant to the terms of the Lock-up Agreement, it has been agreed that the First Bilateral Facility will be replaced by a US$20 million facility in Accugas Holdco (the **"Reinstated First Bilateral Facility"**). The Reinstated First Bilateral Facility will mature in 2024 and will be secured by share pledges over Accugas Holdco and Accugas Midco, and by all asset security granted by Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) by share security over, or asset security from, Accugas Limited. Cash interest will accrue on a pay-if-you-can basis at 6 per cent. per annum and paid-in-kind interest will accrue at 8 per cent. per annum.

1.7 ***SUGL Notes***

Pursuant to the terms of the Lock-up Agreement, it has been agreed that SUGL will, upon completion of the Transaction, issue US$ 85 million of notes due 2027 (payable in NGN at the prevailing NAFEX rate) to the holder of SEFL's 10.50 per cent. senior secured notes due 2021 (the **"SUGL Notes"**). The SUGL Notes have an annual amortisation profile of US$ 6 million and a bullet at final maturity. The SUGL Notes will be secured against the interests Savannah is acquiring in the Uquo Field and the Stubb Creek Field. Cash interest will accrue at 8 per cent. per annum and paid-in-kind interest, payable in lieu of cash at the option of SUGL for the first two semi-annual periods only, will accrue at 10 per cent. per annum.

1.8 ***Asset purchase agreements***

Pursuant to the terms of the Lock-up Agreement, on Completion certain entities from the Seven Group will enter into asset sale and purchase agreements with certain members of the Existing Group. These agreements will effect the transfer of the Seven Assets to the Existing Group. Certain of the selling Seven Group entities will be in administration and act by their administrators. The asset purchase agreements will be on standard terms for an administration sale, for example, no representations or warranties will be provided in relation to the sale of the Seven Assets.

2 Material contracts relating to the Stubb Creek Field

2.1 *Universal Shareholders' Agreement*

2.1.1 Universal and 20 shareholders out of the 25 shareholders in Universal entered into a shareholders' agreement relating to the Universal in 2012.

2.1.2 The following actions require consent of at least four shareholders that hold together at least 75 per cent. of the entire issued and paid up share capital: (i) changes in the share capital including new share issues, changes in the nominal value of shares, creation of equity securities including debentures, issue of equity related securities, options, similar rights, changes to class rights (changes in the share capital related to employee share options or similar rights are carved out); (ii) any change in the constitutional documents or change of rights attaching to the shares and changes to the rules of procedure of the company's management bodies; (iii) creation of new subsidiaries and expansion of Universal's business other than through Universal or a wholly-owned subsidiary; (iv) listing on any market and any public offer of shares; (v) liquidation, winding up, reorganisation or insolvency proceedings in respect of Universal; and (vi) any material change the nature of Universal's primary business.

2.1.3 Supermajority approval of the board (by 75 per cent. of board members) is required to take the following actions: (i) change of name, domicile or head office; (ii) any change in the capital structure; (iii) employee profit sharing schemes; (iv) borrowings, authorisation, issuance or redemption of debt (incl. guarantees) above agreed thresholds set by the board from time to time; (v) change of fiscal year or accounting reference period; (vi) approval of business plan and annual and other budgets, annual balance sheet and profit and loss statement; (vii) appointment of auditors, change in accounting policies of the Company and any key subsidiary; (viii) related party transactions with a value of over Naira 10 million in any year except those approved in the Business Plan/Annual Budget; (ix) commencement of legal or arbitral proceedings where the amount in dispute is, or the value of the matter is assessed by the Managing Director to be more than Naira 50m; and (x) commercial agreements involving amounts in excess of limits set by the board from time to time.

2.1.4 *Share transfers*

(a) The board of Universal may decline to register a transfer of shares on which Universal has a lien. Any transfer of shares in breach of the Universal SHA shall be void and shall not be recognised or registered by the Company.

(b) A right of first refusal applies in relation to transfers of shares to a third party for cash. Transfers of shares to affiliates, and to a purchaser under drag-along and tag-along provisions following a duly served drag-along or tag-along notice, are carved out.

(c) Upon receiving an offer to sell the entire issued share capital of Universal, Shareholders holding 80 per cent. or more in Universal may by written notice require the remaining shareholders to sell their shares.

(d) A tag along right is triggered by an offer to sell 60 per cent. or more of the entire issued share capital of Universal, if following such proposed transfer the buyer would hold 60 per cent. or more of Universal. The remaining shareholders may require that the selling shareholders procure that the buyer makes an offer for the same proportion of the shares of each remaining shareholder as the proportion of the selling shareholders' shares in respect of which the buyer has made the offer. If the buyer fails to purchase the relevant shares from the remaining shareholders following the tag along notice, the selling shareholders may not proceed with the sale of their shares.

2.1.5 Shareholders have pre-emptive rights on issues of new shares, options, warrants for shares or other instruments convertible into equity except employee options.

2.1.6 Each holder of 10 per cent. of the shares has the right to appoint one director. From 1 January 2013 the board consists of 10 directors comprising six directors appointed by SEPL; one director appointed by Akwa Ibom Investment and Industrial Promotion Council; and three directors appointed by the remaining shareholders acting together. The quorum for board meetings is three directors, including at least one SEPL and one non-SEPL director.

2.1.7 The quorum for shareholder meetings is five shareholders present in person or by proxy provided that such shareholders hold together at least 75 per cent. of the issued shares in the Company. The chairman of the Board has a casting vote at general meetings.

2.2 ***Stubb Creek Field Farm-out Agreement***

2.2.1 On 25 February 2003 the MPR granted Universal the right to operate the Stubb Creek Field as a marginal field. Pursuant to the Marginal Field Guidelines, at this time, the area also became independent of OML 14 (now OPL 276) for operational purposes. On 22 December 2003, NNPC, SPDC, Elf and AGIP, as a joint venture, agreed to terms of a farm-out agreement under which the Stubb Creek Field would be developed by Universal as operator (the **"Stubb Creek FOA"**). The term of the Stubb Creek FOA was for an initial period of sixty months which is understood to have now expired.

2.2.2 Although the initial term of the Stubb Creek FOA appears to have expired, the agreement may continue to be binding on the Stubb Creek Field licensees until the field is abandoned or revoked. This is because the Marginal Field Guidelines appear to provide that the farm-out agreement which transfers rights to a marginal field becomes tied to the term of the marginal field licence. There are a number of inconsistencies in the Marginal Field Guidelines, however, and as such, there is a certain level of uncertainty on this point. Until the courts rule on such a dispute or the DPR clarifies the relationship between these farm-out agreements and the respective marginal field licences, it is unclear as to whether or not the Stubb Creek FOA will continue to be binding on the Stubb Creek Field licensees until the field is abandoned or revoked or whether it expired at the end of its 60 month term. Universal's position is that the Stubb Creek FOA has been extended in line with the term of the marginal field award and that it continues to apply.

2.2.3 The Stubb Creek FOA requires Universal to pay to the Stubb Creek FOA farmors an overriding royalty on crude oil production at the following rates: (i) 2.5 per cent. of the value of daily production up to 2,000 bopd; (ii) 3 per cent. of the value of daily production from 2,001 to 5,000 bopd; (iii) 5.5 per cent. of the value of daily production from 5,001 to 10,000 bopd; (iv) 7.5 per cent. of the value of daily production from 10,001 to 15,000 bopd; and (v) the parties are to negotiate and agree the overriding royalty rate to be paid on production in excess of 15,000 bopd. At the date of this Admission Document, daily production has not exceeded 15,000 bopd. For the production of natural gas, Universal pays an overriding royalty of: (i) 0 per cent. of the value of daily production below 20 MMscfpd; and (ii) the parties are to agree the overriding royalty rate to be paid on daily production above 20 MMscfpd. At the date of this Admission Document, no gas royalty is paid for the Stubb Creek Field as the field is not producing more than 20 MMscfpd. The farmors can lift their crude oil entitlement from the field or elect to receive their royalty in US$ equivalent at the prevailing market prices for the crude oil on the date of payment. In the event the government asserts any right it may have to acquire an interest in the Stubb Creek Field, Universal has a best endeavours obligation to ensure the government assumes a corresponding part of Universal's obligations and liabilities under the Stubb Creek FOA.

2.2.4 Under the Stubb Creek FOA if Universal owes money to the farmors for a continuous period of three months, Universal will be in default. If Universal is deemed to be in default it is deemed to have granted to the farmors a lien on all crude oil produced from the Stubb Creek Field and the proceeds from such production to secure discharge of the owed amounts plus interest. During any period of default, Universal is not entitled to its production from the Stubb Creek Field, which will vest in and be the property of the farmors. The farmors are entitled to sell the production and, after deducting all costs incurred during the sale, are entitled to recover from the remaining proceeds all amounts owed to the farmors by Universal.

2.2.5 The Stubb Creek FOA may be terminated immediately if: (i) Universal becomes bankrupt and is forced to make restitution to its creditors or insolvent or wilfully violates Nigerian laws and regulations governing petroleum operations, financial transactions and/or commercial operations; (ii) the DPR determines that Universal is not complying with Nigerian petroleum laws, regulations or environmental health and safety standards with respect to operations undertaken in respect of the Stubb Creek Field (after a 90 day cure period); (iii) Universal assigns its rights and interests in the Stubb Creek Field without the written consent of the Nigerian

Government; (iv) Universal intentionally extracts or produces petroleum outside the farm-out area; or (v) Universal fails to remedy or remove a material breach (as defined in the agreement to include a substantial breach of the Stubb Creek FOA which may include breaches of health/environmental standards, confidentiality obligations, abandonment security obligations, insurance obligations, creation of encumbrances contrary to the agreement, intentional submission of false information to the Nigerian Government or where the DPR notify that the Stubb Creek Field operations are interfering with the farmor's operations) of the Stubb Creek FOA within a 90 day cure period. The Stubb Creek farmors can also terminate on 30 days' notice if Universal ceases operations for more than 90 days without acceptable cause or justification.

2.2.6 The Stubb Creek FOA requires farmees to provide security funds to satisfy abandonment obligations with such security funds being reduced or released as the underlying obligations and liabilities are met, reduced or released. Upon commencement of operations and prior to submission of its first work programme to the DPR, the farmees and farmors are required to enter into an abandonment security agreement. To date, an abandonment security agreement has not been agreed by the parties, however, NNPC (the only remaining farmor) has not attempted to enforce this obligation or enter into an abandonment security agreement with the farmees.

2.2.7 A party must give the other party notice of a force majeure situation within 24 hours of such a situation occurring along with an estimate of how long its resolution might take. The obligations of the party giving notice of force majeure (other than payments of amount due or furnishing security) will then be suspended. There is a reasonable endeavours obligation on the party giving notice to remove or overcome the force majeure situation as quickly as possible in an economic manner.

2.3 ***Stubb Creek Funding Agreement and Joint Operating Agreement***

2.3.1 On 11 August 2010, Universal and Sinopec entered into a joint operating agreement to set out the parties' obligations with respect to the conduct of petroleum operations in the Stubb Creek Field (**"Stubb Creek JOA"**). The Stubb Creek JOA designates Universal as the operator and Sinopec as the funding partner and technical advisor of the Stubb Creek Field.

2.3.2 Pursuant to the Stubb Creek JOA, Universal agreed to assign an undivided 49 per cent. legal interest in the Stubb Creek Field to Sinopec. The assignment of Universal's 49 per cent. legal interest in the Stubb Creek Field to Sinopec was approved by the MPR on 8 June 2015.

2.3.3 On 11 August 2010, Universal and Sinopec also entered into a funding agreement which set out the parties' respective funding obligations and profit allocations with respect to exploration, development and production of the Stubb Creek Field (the **"Stubb Creek FA"**). The terms of the of the Stubb Creek JOA and Stubb Creek FA run concurrently with the term of the Stubb Creek FOA. Therefore, once the Stubb Creek FOA terminates or expires, the Stubb Creek JOA and Stubb Creek FA shall also terminate or expire.

2.3.4 Pursuant to the Stubb Creek FA and Stubb Creek JOA , Universal is required to provide 20 per cent. and Sinopec 80 per cent. of funding for crude oil and associated natural gas developments and Universal is entitled to 35 per cent. and Sinopec 65 per cent. of profits from crude oil and associated natural gas developments. Universal is required to provide 50 per cent. and Sinopec 50 per cent. of funding for non-associated natural gas developments and Universal is entitled to 60 per cent. and Sinopec 40 per cent. of profits from non-associated natural gas developments. Universal is responsible for all royalties, taxes, rates and assessments that may be imposed under the Stubb Creek FOA and must make all payments due to the farmors under the Stubb Creek FOA.

2.3.5 If Universal or Sinopec fails to pay a cash call, that party is in default under the Stubb Creek JOA and the other party is authorised to sell the defaulting party's share of petroleum. If the defaulting party fails to pay over three consecutive cash calls, a penalty of 20 per cent. of the total amounts owed is added to the sum due by the defaulting party (in addition to compound interest and taxes). If Sinopec fails to pay five consecutive cash calls, its profit oil allocation is decreased from 49 per cent. to 0 per cent. and if Universal fails to pay five consecutive cash calls, its profit oil allocation is decreased from 51 per cent. to 15 per cent.

2.3.6 The Stubb Creek JOA provides that decision-making in relation to all matters pertaining to the conduct of petroleum operations and preparation of the field development plan of the Stubb Creek Field is conducted through a project management committee. The project management committee consists of eight members: four appointed by each of Universal (one to be the project manager) and Sinopec (one to be the deputy project manager). Universal also appoints the project management committee Chairman and Sinopec appoints the project management committee Secretary.

2.3.7 Pursuant to the Stubb Creek JOA, decisions in respect of production and the development of the Stubb Creek Field require the joint consent of Universal and Sinopec. In the event of a deadlock:

(a) in respect of crude oil and associated natural gas developments, the dispute resolution provisions in the Stubb Creek JOA will be initiated; and

(b) in respect of non-associated natural gas development, Universal, as operator, has a casting vote and the decision of the operator will be adopted.

2.3.8 Pursuant to the Stubb Creek JOA, no party shall be liable for the failure to perform, or for delays in performing any obligations to the extent that such failure or delay in performance was attributed to an event of force majeure. In the event of force majeure, a party affected by such an event must give notice to the other party as soon as reasonably possible, stating the date, cause and extent of such event. Any party whose obligations have been suspended by the event of force majeure shall resume the performance of such obligations as soon as reasonably possible after the force majeure event has ended/been removed.

2.3.9 Either party may terminate the Stubb Creek JOA if any of the following events occur: (i) default of a material obligation by the other party (that is not remedied within a 30 day cure period); (ii) assignment of the Stubb Creek JOA without the prior written notice and consent of the other party; (iii) a party is adjudged insolvent, bankrupt or to have made restitution to its creditors by a court of competent jurisdiction in Nigeria; or (iv) a party liquidates or terminates its corporate existence. Sinopec also has a right (as a major financial contributor) to withdraw with immediate effect if it is found that the proven reserves cannot be economically produced, and additionally Sinopec may reassign its rights to Universal on three months' notice.

3 Material contracts relating to the Uquo Field

3.1 *Uquo Farm-out Agreement*

3.1.1 On 25 February 2003, the DPR granted Frontier the right to operate the Uquo Field as a marginal field. Pursuant to the Marginal Field Guidelines, at this time, the area also became independent of OML 13 for operational purposes. On 27 April 2004, NNPC, SPDC, Elf, and AGIP, as a joint venture, agreed to terms of a farm-out agreement under which the Uquo Field would be developed by Frontier (the **"Uquo FOA"**). The term of the Uquo FOA was for an initial period of sixty months which is understood to have now expired.

3.1.2 Although the initial term of the Uquo FOA appears to have expired, the agreement may continue to be binding on the Uquo Field operator until the field is abandoned or revoked. This is because the Marginal Field Guidelines appear to provide that the farm-out agreement which transfers rights to a marginal field becomes tied to the term of the marginal field licence. There are a number of inconsistencies in the Marginal Field Guidelines, however, and as such, there is a certain level of uncertainty on this point. Until courts rule on such a dispute or the DPR clarifies the relationship between these farm-out agreements and the respective marginal field awards, it is unclear whether or not the Uquo FOA will continue to be binding on the Uquo Field licensees until the field is abandoned or revoked or whether it expired at the end of its 60 month term. In contrast to Universal's position on the Stubb Creek FOA, Frontier's position is that the Uquo FOA has expired and therefore it does not owe overriding royalty payments to NPDC, an NNPC subsidiary that is the current holder of the OML. No payments have been made by the Uquo JV with respect to overriding royalties, so there are historic amounts outstanding.

3.1.3 Pursuant to a deed of assignment dated 15 May 2006, Frontier assigned a 40 per cent. legal interest in the Uquo Field to Red Rock Energy Limited (**"Red Rock"**). Red Rock then assigned the interest to SUGL, a wholly owned subsidiary of Seven Energy (BVI), itself an affiliate of Red Rock. This assignment was approved by the MPR on 3 October 2007.

3.1.4 The Uquo FOA requires Frontier to pay to the Uquo FOA farmors an overriding royalty on crude oil production at the following rates: (i) 2.5 per cent. of the value of daily production up to 2,000 bopd; (ii) 3 per cent. of the value of daily production from 2,001 to 5,000 bopd; (iii) 5.5 per cent. of the value of daily production from 5,001 to 10,000 bopd; (iv) 7.5 per cent. of the value of daily production from 10,001 to 15,000 bopd; and (v) the parties are to negotiate and agree the overriding royalty rate to be paid on production in excess of 15,000 bopd. At the date of this Admission Document, daily production has not exceeded 15,000 bopd. For the production of natural gas, Frontier pays an overriding royalty of: (i) 0 per cent. of the value of daily production below 20 MMscfpd; and (ii) the parties are to negotiate and agree the overriding royalty rate to be paid on daily production above 20 MMscfpd. At the date of this Admission Document, daily production of natural gas has exceeded 20 MMscfpd, but no agreement has been made between the parties as to the level of the overriding royalty rate as Frontier believes the Uquo FOA has expired and therefore does not owe an overriding royalty to the farmors. The farmors can lift their crude oil entitlement from the field or elect to receive their royalty in US$ equivalent at the prevailing market prices for the crude oil on the date of payment. In the event the government asserts any right it may have to acquire an interest in the Uquo Field, Frontier has a best endeavours obligation to ensure the government assumes a corresponding part of Frontier's obligations and liabilities under the Uquo FOA.

3.1.5 Under the Uquo FOA if Frontier owes money to the farmors for a continuous period of 3 months, Frontier will be in default. If Frontier is deemed to be in default it is deemed to have granted to the farmors a lien on all crude oil produced from the Uquo Field and the proceeds from such production to secure discharge of the owed amounts plus interest. During any period of default, Frontier is not entitled to its production from the Uquo Field, which will vest in and be the property of the farmors. The farmors are entitled to sell the production and, after deducting all costs incurred during the sale, are entitled to recover from the remaining proceeds all amounts owed to the farmors by Frontier.

3.1.6 The Uquo FOA may be terminated immediately if: (i) Frontier becomes bankrupt and is forced to make restitution to its creditors or insolvent or wilfully violates Nigerian laws and regulations governing petroleum operations, financial transactions and/or commercial operations; (ii) the DPR determines that Frontier is not complying with Nigerian petroleum laws, regulations or environmental health and safety standards with respect to operations undertaken in respect of the Uquo Field (after a 90 day cure period); (iii) Frontier assigns its rights and interests in the Uquo Field without the written consent of the Nigerian Government; (iv) Frontier intentionally extracts or produces petroleum outside the farm-out area; or (v) Frontier fails to remedy or remove a material breach (as defined in the agreement which may include a substantial breach of the Uquo FOA, breaches of health/environmental standards, confidentiality obligations, abandonment security obligations, insurance obligations, creation of encumbrances contrary to the agreement, intentional submission of false information to the Nigerian Government or where the DPR notify that the Uquo Field operations are interfering with the farmor's operations) of the Uquo FOA within a 90 day cure period. The Uquo farmors can also terminate on 30 days' notice if Frontier ceases operations for more than 90 days without acceptable cause or justification.

3.1.7 The Uquo FOA requires farmees to provide security funds to satisfy abandonment obligations with such security funds being reduced or released as the underlying obligations and liabilities are met, reduced or released. Upon commencement of operations and prior to submission of its first work programme to the DPR, the farmees and farmors are required to enter into an abandonment security agreement. To date, an abandonment security agreement has not been agreed by the parties and there has been no attempt to enforce this obligation or enter into an abandonment security agreement with the farmees.

3.1.8 A party must give the other party notice of a force majeure situation within 24 hours of such a situation occurring along with an estimate of how long its resolution might take. The obligations of the party giving notice of force majeure (other than payments of amount due or furnishing security) will then be suspended. There is a reasonable endeavours obligation on the party giving notice to remove or overcome the force majeure situation as quickly as possible in an economic manner.

3.2 ***Uquo Field Joint Operating Agreement***

3.2.1 On 9 January 2007, Frontier and SUGL entered into a joint operating agreement to set out the parties' obligations with respect to the conduct of petroleum operations in the Uquo Field (the **"Uquo JOA"**). The Uquo JOA designates Frontier as operator and SUGL as technical partner of the Uquo Field. The term of the Uquo JOA runs concurrently with the term of the Uquo FOA, therefore, once the Uquo FOA terminates or expires, the Uquo JOA shall also terminate or expire (subject to final settlement being made).

3.2.2 The Uquo JOA has been amended from time to time to reflect the changes in the parties' interests. An additional amendment agreement taking the form of a side letter is expected to be executed prior to completion of the Transaction. The terms of this side letter have largely been agreed between Frontier and SUGL and it currently applies to the parties by conduct; this summary therefore reflects the current draft of this side letter. The Uquo JOA (as amended) requires SUGL to commit up to $105 million of funding for the development of the Uquo Field gas project and $45 million of funding for the development of the Uquo Field oil project. To date, SUGL has provided in excess of the gas project funding requirement but $30 million remains outstanding with respect to the oil project.

3.2.3 The terms of the Uquo Field JOA provide that SUGL pay 100 per cent. of the capital and operating costs of the oil and gas operations carried out by Frontier as operator of the field. However, once the net revenue from oil operations or gas operations (including a 15 per cent. return on investment) exceed the capital and operating costs which SUGL have paid and which remain unrecovered in respect of such operations (the **"Payout"**), SUGL's obligation to pay 100 per cent. of the capital and operating costs is reduced to 52 per cent. and 48 per cent. of such costs for oil and gas development, respectively.

3.2.4 With respect to oil operations, SUGL is entitled to receive 85 per cent. of revenue until Payout (including a 15 per cent. return on investment) in respect of such oil operations, following which such entitlement reduces to a target of 52 per cent. With respect to gas operations, SUGL is entitled to receive 87.7 per cent. until Payout (including a 15 per cent. return on investment) in respect of such gas operations, following which such entitlement reduces to a target of 48 per cent. After Payout, the target revenue entitlement is achieved by the revenue sharing schedule set forth in the Uquo Field JOA.

3.2.5 As operator, Frontier is responsible for conducting all operations on behalf of the joint venture parties in respect of oil and gas developments in the Uquo Field, including all associated administrative tasks. Decisions in respect of the Uquo Field's oil and gas operations are taken by a joint operating committee which has the power to authorise, direct and supervise Frontier, acting as operator, in its conduct of joint operations. The joint operating committee is made up of four members, two of whom are appointed by Frontier and two of whom are appointed by SUGL. At least one representative from each party must be present at a resolution of the joint operating committee in order for the meeting to be quorate and all decisions require the unanimous vote of Frontier and SUGL. Whilst Frontier is responsible for preparing annual work programs and budgets, the work programs and budgets require approval of the joint operating committee.

3.2.6 The Uquo JOA includes a number of events of default, including: (i) failure to pay joint account expenses; (ii) breach of any representation or warranty under the agreement which would reasonably be expected to have a material and adverse effect on the non-defaulting party; (iii) failure to perform any obligation under the agreement which would reasonably be expected to have a material and adverse effect on the non-defaulting party; and (iv) a court is appointed as liquidator for a party or any substantial portion of the party's assets or a party is declared or voluntarily declares itself bankrupt or insolvent. During any such event of default, subject to certain notice and cure periods, the defaulting party will not be entitled to vote on, joint operating committee decisions, and, if the default is not remedied by the 180th day following the default, the non-defaulting party may require the defaulting party to withdraw from the Uquo JOA. In addition, in the event SUGL fails to provide its minimum investment commitment as it related to the oil project, Frontier has the right as it relates to the oil project to terminate the Uquo JOA (and SUGL will be required to transfer back to Frontier its interest in the oil project and forfeit all corresponding investments in the farm-out area) upon 30 days' notice if such breach is not cured and if the parties have not reached mutual agreement otherwise. In the event SUGL fails to pay a cash call made by Frontier as operator, Frontier is entitled (following written notice) to pay such amounts on behalf of SUGL and deem such amounts to be loan (with interest set out in the agreement). SUGL has failed to pay a number of cash calls and so is currently in default under the Uquo JOA. Frontier served a default notice on SUGL on 11 December 2017 regarding the unpaid cash calls (which date back to 2016) and alleging a default under other provisions of the Uquo JOA on the basis that SUGL is unable to pay its debts as they fall due. It is intended that the Enlarged Group will settle at Completion any of such unpaid cash calls due to Frontier to the extent they remain unpaid at Completion as part of reaching an agreed remedy in respect of this default notice.

3.2.7 The Uquo JOA provides that if either party has (or is interested in) an interest within 10 kilometres of the Uquo Field, such party must give the other party the right to participate in that interest by no less than 40 per cent.

3.2.8 If, as a result of force majeure, either party is rendered unable, wholly or in part, to carry out its obligations under the Uquo JOA then following the issuance of a notice of force majeure (which shall be provided within a reasonable time of such event occurring) such obligations shall be suspended until the force majeure event ceases to impact the party's ability to carry out its obligations and such reasonable period of time to allow the party to put itself into the position it was in prior to the force majeure event. If a party remains unable to perform its obligations under the Uquo JOA due to force majeure event for a period of six months (following the issuance of a force majeure notice) then the other party may, at its sole discretion issue a notice of termination which will be deemed to have taken effect when issued. If the Uquo JOA is terminated pursuant to an event of force majeure neither party shall remain liable to the other except where payments have been paid for performance which has not been delivered and where obligations for payment existed prior to termination.

3.3 ***Uquo Field Technical Services Agreement***

3.3.1 On 9 January 2007, Frontier and SUGL entered into the Uquo Field TSA which sets out the terms on which SUGL provides technical advice, support and assistance to Frontier in the discharge of its responsibilities and duties as operator under the Uquo JOA. The term of the agreement is the same as provided for under the Uquo JOA, unless otherwise agreed. The agreement will also terminate in the event that the Uquo FOA expires or terminates, or in the event that SUGL transfers its entire interest in the Uquo Field.

3.3.2 The services which SUGL provide under the agreement include: (i) advisory and management services; (ii) seismic acquisition, processing and interpretation services; (iii) drilling planning and execution services; (iv) provision of surface facilities design, sub-surface technologies and early production system; (iv) procurement and supply chain management services for seismic, drilling and production facilities; (vi) training and development services; and (vii) such other technical services as may be agreed between the parties.

3.3.3 The Uquo Field TSA also contemplates that SUGL may engineer and manage the project development of enhanced gas monetisation projects which may be undertaken as a separate project dealt with under separate agreements. Under the Uquo Field TSA, the budget or cost of any services provided by SUGL is to be agreed with Frontier as operator of the Uquo Field.

4 Uquo Field and Stubb Creek Field – Oil Handling and Sales Agreements

4.1 *Mobil Crude Handling Agreement*

4.1.1 On 30 November 2012, MPN in its capacity as operator of the QIT, entered into a crude handling agreement with Frontier Oil Nigeria Limited, Universal and Network Exploration & Production Nigeria Limited (together, the **"FUN Group"**) with respect to this paragraph 4.1) (**"CHA"**). The term of the CHA was for five years from the date of execution, expiring at the end of November 2017, however, the parties plan to extend the initial term and are in the process of agreeing an extension; the parties are continuing to apply the terms of the CHA pending such extension.

4.1.2 The CHA provides that oil (**"Qua Iboe Crude"**) produced by the FUN Group will be shipped through the oil infrastructure of the QIT. In consideration, the FUN Group must pay MPN monthly tariffs as recalculated and adjusted annually based on actual cash and non-cash operating costs. The FUN Group first delivered Qua Iboe Crude to MPN on 31 January 2015. There is a send or pay obligation allowing the FUN Group to either deliver the required quantity of crude oil each year or make payments (as calculated by a formula in the agreement) for such quantity.

4.1.3 The CHA provides that MPN may terminate the agreement: (i) upon termination of the ExxonMobil COSA (as defined below), (ii) upon cessation of MPN operating the QIT, (iii) due to the FUN Group's failure to deliver by reason of force majeure for a period of six consecutive months, (iv) due to the FUN Group's failure to deliver crude which fails to meet the agreed specification for a period of 12 consecutive months or (v) there is a change to the FUN Group's financial circumstances.

4.1.4 The CHA provides that the FUN Group may terminate the agreement: (i) if a FUN Group marginal field ceases to be a producing field, (ii) where MPN fails to accept Qua Iboe Crude for a period of six consecutive months or fails to deliver Qua Iboe Crude at the delivery point, (iii) the FUN Group are (having used reasonable endeavours to do so) unable to deliver crude or deliver crude at the agreed specification for a period of 12 consecutive months.

4.1.5 Either party may terminate the CHA if there is a payment default, prolonged force majeure or a change in financial circumstances. A payment default is defined in the agreement as when a party fails to pay any sum 30 days after the payment date. A prolonged force majeure is where either party is excused from its obligations due to a force majeure event for a period of 24 consecutive months. A change in financial circumstances is defined in the agreement as when MPN has reasonable grounds to believe that the FUN Group will cease to have the financial resources to meet its obligations under the CHA.

4.1.6 Pursuant to the CHA, a party shall be excused from failing to perform its obligations in whole or part if such failure is attributed to an event of force majeure other than to the extent that a party is required from making timely payments of any monies due which became payable prior to the event of force majeure. A party claiming force majeure shall promptly notify the other parties of the nature and extent of the force majeure and shall keep the other parties informed of steps being taking in relation to such event.

4.1.7 By a separate and concurrent agreement described in paragraph 4.2 below, MPN's affiliate, ExxonMobil Sales and Supply LLC (**"ExxonMobil"**), committed to purchase all volumes of Qua Iboe Crude stored and transferred by MPN.

4.2 *ExxonMobil Crude Oil Sales Agreement*

4.2.1 On 30 November 2012, ExxonMobil and the FUN Group entered into an agreement pursuant to which the FUN Group have agreed to sell Qua Iboe Crude to ExxonMobil (the **"ExxonMobil COSA"**).

4.2.2 The term of the ExxonMobil COSA commenced on the effective date of the CHA and continues throughout the term of the CHA. As noted above, the CHA expired at the end of November 2017 and consequently the term of the ExxonMobil COSA will also expire once the termination conditions in the agreement have been met. The ExxonMobil COSA states that in the event that the CHA is terminated, the ExxonMobil COSA will automatically terminate on the earlier of: (i) the end of the third full month following the date of termination of the CHA; and (ii) the date of ExxonMobil's payment for the purchase of the remaining inventory of the FUN Group in the QIT. However, the discussions regarding the renewal/extension of the CHA also contemplate the extension of the ExxonMobil COSA and the parties are continuing to treat this agreement as in force pending such renewal/extension.

4.2.3 The ExxonMobil COSA specifies that the quantity of Qua Iboe Crude to be sold under the agreement, which is determined at monthly production curtailment and lifting schedule meetings with NNPC and MPN. However, the FUN Group reserves the right to deliver a quantity less than that shown in the lifting schedule in the event of production changes, weather, operational reasons or any other matters beyond the control of the FUN Group.

4.2.4 The contract price per barrel for a particular month of lifting is determined in accordance with the following formula: the average of the dated Brent quotations published in Platts in the month of lifting plus the average of the differential for Qua Iboe Crude to dated Brent published in the period starting on the twentieth day of the second month prior to the month of lifting through the nineteenth day of the first month prior to the month of lifting; less a logistics margin of 0.125 per cent. of the price component determined as described above (subject to the logistics margin not being less than US$0.11 per barrel). In the pricing formula, where available, the differential for Qua Iboe Crude to dated Brent is calculated on a 50/50 basis using information published in Platts and Argus Media. There is no take-or-pay obligation on ExxonMobil and title to and risk of loss passes from the FUN Group to ExxonMobil as the cargo passes the permanent inlet flange of the vessel at the load port.

4.2.5 Pursuant to the ExxonMobil General Terms and Conditions (March 1997 edition) (**"GTC"**) (which are incorporated by reference into the terms of the ExxonMobil COSA), neither party shall be liable for loss or damage, including indirect or consequential damage, under the terms of the agreement due to a force majeure event which is beyond its reasonable control. Pursuant to the GTCs, ExxonMobil is not obligated to purchase additional crude oil during a period of force majeure to make up deliveries omitted during the period of disruption nor will the term of the ExxonMobil COSA be automatically extended due to such an event. The party affected by the force majeure is required to give prompt notice to the other party providing sufficient details relating to the event and the estimated scope of disability caused by such an event.

4.3 ***FUN JOA***

4.3.1 On 28 August 2014, the FUN Group (as operators of the Uquo, Stubb Creek and Qua Iboe marginal fields) entered in a joint operating agreement with respect to certain facilities which connect to the QIT through which they export processed crude oil ("**FUN JOA**").

4.3.2 The FUN JOA became effective upon its date of execution and has effect until all materials, equipment and personal property used in connection with the operations envisaged by the FUN JOA have been removed and disposed of and final settlement has been made among the parties.

4.3.3 Frontier is the designated operator of the FUN JOA and each member of the FUN Group has an equal 1/3 participating interest in the FUN JOA. All rights and interests in the joint property are held by the FUN Group in trust for the members of their respective field's joint venture in accordance with their respective participating interest in the FUN JOA.

4.3.4 All capital expenditure and all liabilities incurred by the operator in connection with the joint operations are shared in accordance with the parties' participating interests. The cost of fixed operating expenditures is shared by the parties in accordance with their participating interests. The cost of variable operating expenditures is shared by the parties in accordance with the volumes of crude oil they each deliver under the FUN JOA. Each party pays its share of variable operating expenditure based upon the ratio of crude oil it delivers against the total volume of crude oil delivered by the parties.

4.3.5 Each party is entitled to use its participating interest share in the capacity of the facilities. In the event of a shutdown or constraint affecting the facilities the parties shall share rateably in the constraint and reduced volume. Each party has the right to permit the other parties to utilise its spare capacity on such terms as the parties may agree.

5 Material contracts relating to the Midstream Assets

5.1 *Accugas term sheet*

5.1.1 The Company entered into a term sheet with AIIM and one other potential co-investor in respect of Accugas on 3 December 2017.

5.1.2 The term sheet includes the following legally binding provisions:

(a) not to negotiate, solicit, or enter into any agreement with any other person relating to any investment in or the acquisition of shares in or any part of the business of SEIL or any of its subsidiaries (in the case of the Investors), or any investment in or the acquisition of shares in or any part of the business of Accugas (in the case of the Company);

(b) to work together in good faith to negotiate the terms of a shareholders' agreement in relation to Accugas, on the principles of the key terms as set out in the term sheet;

(c) to maintain confidentiality; and

(d) not to make any announcement relating to the term sheet or the involvement of any other party in the Transaction or the Accugas Transaction without the consent of the other parties (subject to limited exceptions).

5.1.3 The non-binding provisions of the term sheet include the following:

(a) The Investors shall form a new company (**"Accugas Topco"**) to invest in Accugas Holdco. Accugas Topco shall invest US$60 million for 80 per cent. of Accugas Holdco. The Company shall have 20 per cent. of Accugas Holdco in consideration of paying US$15 million of the costs payable by Accugas Topco. The Company shall pay 60 per cent. of the due diligence and implementation costs relating to the acquisition of assets from Seven and Accugas Topco shall pay 40 per cent. up to an amount of US$35.3 million. If such costs exceed US$35.3 million, Accugas Topco shall pay 40 per cent. of the excess costs incurred for engaging advisers to SEIL, the noteholders and the Company directly connected to the implementation of the restructuring of SEIL and the Company shall pay the remainder of the costs. Otherwise, the Company and Accugas Topco shall each pay their own costs.

(b) The Investors agreed to keep the Company informed regarding the steps and timetable for approval of the documents and agreed to publically support the Transaction.

(c) The Company and the Investors agreed to negotiate a relationship agreement on basis of the principles set out in the term sheet. The anticipated terms of the relationship agreement are summarised in paragraph 5.1.6 of this Part 14.

(d) The Company and the Investors also agreed the principles of the GSA to be entered into between Accugas Limited, Frontier and SUGL. The terms of the GSA are summarised in paragraph 5.1.7 of this Part 14.

(e) The Company and the Investors agreed that where a shareholder or the board of Accugas Limited wishes to undertake a project requiring any capital expenditure that requires the raising of new capital by Accugas, the Shareholders shall vote on the matter. If the Shareholders approve, Accugas Limited shall proceed with the project and the Company shall have the right to review the design, construction and installation of the project and Accugas Limited shall have regard to the Company's comments on such matters. If the Shareholders do not approve a project proposed by the Company, the Company may pursue the project on a sole risk basis at its own cost and Accugas Limited shall provide reasonable assistance on commercial terms to facilitate a successful implementation of the project.

(f) The Company and the Investors also agreed the principles of the shareholders' agreement relating to Accugas Holdco. The terms of the shareholders' agreement are summarised in paragraph 5.1.5 of this Part 14.

5.1.4 *Investment Agreement*

The Company and the Investors have entered into a conditional investment agreement in connection with the Accugas Transaction. The agreement will be novated to Eight Holdco and Accugas Topco. The Investors agreed that Accugas Topco will enter into the an asset purchase agreement in relation to Accugas (the "**Accugas APA**") and provide a shareholder loan of at least US$45 million to Accugas and the Company agreed the terms on which the receivable from Accugas Holdco, which is to be acquired under the Accugas APA, will be repaid to Eight Holdco. The agreement is conditional on: (i) Accugas Topco approving the terms of the Implementation Agreement, the Relationship Agreement and new GSA with the Uquo JV; (ii) the execution of a letter regarding the sharing of costs; (iii) the execution of an agreement with the Uquo JV settling outstanding payables and confirming entry into the Frontier Agreements; (iv) the approval of the agreements to be entered into for the refinancing of the Accugas IV Facility Agreement and the DSA Facility Agreement; (v) completion of certain steps in the Implementation Agreement and the Accugas APA; (vi) the submission of documents necessary for the registration of title of the land relating to the East Horizon Pipeline; (vii) approval and registration by the Akwa Ibom State of the change in ownership of the interest in the CPF sub-lease as a result of the Accugas Transaction (if required); (viii) any waiver required under the Calabar GSA or Unicem GSA as a result of the restructuring of the Accugas IV Facility Agreement; and (ix) approval of the terms of the Reinstated First Bilateral Facility. The parties have also agreed the form of the shareholders, agreement regarding Accugas HoldCo.

5.1.5 *Accugas Shareholders' Agreement*

(a) Accugas Topco and the Company (the **"Shareholders"** for the purpose of this paragraph 5.1.5) will enter into a shareholders' agreement, which is in agreed form on signing of the investment agreement referred to in paragraph 5.1.4 above, relating to Accugas Holdco on completion of the Accugas Transaction.

(b) Accugas Topco will grant Savannah the option to acquire a further 10 per cent. of Accugas Holdco at a price equal to 10 per cent. of the total invested capital uplifted at an annualised rate of 10 per cent. The additional 10 per cent. holding in Accugas Holdco will not be carried by Accugas Topco.

(c) There shall be no more than five directors on the board of Accugas Holdco. The Company shall have the right to appoint two directors and Accugas Topco shall have the right to appoint three directors.

(d) There shall be no more than four directors on the board of Accugas Limited. The Company shall have the right to appoint one director of Accugas Limited and Accugas Topco shall have the right to appoint two directors of Accugas Limited. The CEO shall be a director of Accugas Limited. Accugas Topco shall propose candidates for the role of chief executive officer of Accugas and the CEO shall be appointed with the joint approval of the Company and Accugas Topco.

(e) The Shareholders shall approve the initial five year business plan. Each subsequent business plan and budget shall be prepared by the management of Accugas Limited and submitted annually to the board of Accugas Holdco for approval.

(f) Any funding required for the business plan beyond the initial funding (excluding emergency funding (see below)), shall be cash called subject to the approval of the Accugas Holdco board and provided on the following basis:

(i) the Investors and the Company shall provide standby funding to cover interest payments in the event of revenue shortfall unforeseen in the business plan, on terms to be agreed.

(ii) Accugas Topco shall provide its *pro rata* proportion of any such cash call by way of a shareholder loan to Accugas Holdco (at an interest rate to be agreed);

(iii) Accugas Topco shall also provide a loan, by way of mezzanine debt ranking behind any other debt, but ahead of Accugas Holdco equity, to Accugas Holdco to cover the costs of Savannah's *pro rata* proportion of any such cash call, which shall be non-recourse to the Company and on which Accugas Holdco shall pay interest at a rate to be agreed (the **"Savannah Carry Loan"**);

(iv) the CEO and CFO of Accugas Limited may jointly notify the Shareholders that the funding of a specific cash call on an emergency basis is required. Where Accugas Topco does not wish to fund the cash call (which shall include carrying the Company's *pro rata* proportion), the Company shall have the right to provide such funding. The terms of any such emergency funding to be agreed (but expected to be significantly more favourable than the initial funding terms); and

(v) if Savannah has exercised its option to acquire further shares in Accugas Holdco, Savannah shall be entitled shall provide the *pro rata* proportion of any such cash call for the shares it has acquired by way of a shareholder loan and if Savannah does not provide such funding, Accugas Topco shall be entitled to provide such funding by way of a shareholder loan or the subscription for further shares or other form of equity securities, provided that its equity interest shall not exceed 80 per cent.

(g) 100 per cent. of profits of Accugas will be distributed, subject to maintaining a minimum US$10 million in cash and the cash waterfall. Where an amount of cash has been identified as available for distribution after service of third party debt in any year, such cash shall be allocated and distributed in accordance with the following priority: (i) first on the repayment of interest and the principal for any emergency shareholder loan, (ii) second, on the repayment of interest and the principal for the Savannah Carry Loan, (iii) third, on the repayment of interest and the principal for each other shareholder loan outstanding (other than the initial funding), (iii) fourth, on the repayment of interest and the principal for each shareholder loan outstanding representing the initial investment, in each case on a "last in first out" basis; and (v) fifth and finally, as a dividend against shares.

(h) The following reserved matters (applicable to Accugas Holdco and Accugas Limited) shall require an 85 per cent. majority vote of the Shareholders:

(i) any change to the articles of Accugas Holdco, the Business, the auditors, the distribution policy, the share capital or share rights;

(ii) the execution of any new agreement or contract relating to any downstream contracts for which the gas supplied for such contract is the Company's gas; and any material amendment, consent or waiver of a material term thereunder;

(iii) any material amendment of any of the three existing downstream contracts, and any material amendment, consent or waiver or any decision not to enforce a term thereunder;

(iv) sale of any fixed assets with a value greater than US$20 million or which are a material part of the infrastructure of the Accugas Midstream Business;

(v) the taking of any external loan which would result in the ratio of debt to EBITDA exceeding 4.0;

(vi) disputes with a value of over US$5 million or relating to the material assets;

(vii) winding up or liquidation;

(viii) adoption of any company or trade name including the word "Savannah";

(ix) any material transaction with a Shareholder or any of its Affiliates, or any guarantee or indemnity not in the ordinary course of business;

(x) mergers and acquisitions, or the entry into of any partnership, joint venture or consortium agreement;

(xi) any issue of share capital; and

(xii) sale of shares in Accugas MidCo, Exoro or Accugas Limited.

(i) The Accugas Holdco board will have the right to approve significant operational matters undertaken by the Accugas Limited board including: (i) any approval of a budget or business plan and (ii) the removal of executive management.

(j) Where a Shareholder (the **"Selling Shareholder"**) wishes to sell all or part of its shareholding (the **"Sale Shares"**) in Accugas Holdco the Selling Shareholder shall notify the other Shareholders (the **"Remaining Shareholders"**) in writing of its intention to sell the Sale Shares; and each Remaining Shareholder may notify the Selling Shareholder in writing of the cash price (the **"Offer Price"**) at which it would be willing to purchase the Sale Shares and the key terms of such purchase (the **"Offer Terms"**). If the Selling Shareholder does not accept any Offer Terms or Offer Price submitted by a Remaining Shareholder then the Selling Shareholder shall be entitled to sell the Sale Shares at a price that is more than the Offer Price and on materially the same terms as the Offer Terms. Where the proposed purchaser is a Matching-Right Transferee (which is a company which is controlled or majority managed by one or more Nigerian national(s) or entity(ies), or which the Company considers, acting reasonably, would restrict or prevent the Company or Accugas from achieving its long-term objectives as a result of such investors' reputation or the leverage in their capital structure) then the Remaining Shareholders shall have the right to acquire the Sale Shares for the same price and on the same terms as offered by such Matching-Right Transferee.

(k) There shall be no restrictions on any direct or indirect sale of shares in Accugas Topco provided that such sale does not result in: (i) the Investor ceasing to control Accugas Topco; or (ii) the ultimate beneficial owners of Accugas Topco being a restricted entity. If the proposed transferee is a Matching-Right Transferee, the transfer shall be prohibited.

(l) The Investors shall, and shall each procure that none of its respective Affiliates shall, own, invest in or have any interest in any entity or business involved in the Nigerian upstream oil and gas industry where such entity or business may wish to supply gas to Accugas or its infrastructure. The Company shall not sell gas to any person within 50 kilometres of the pipeline network or to existing legacy Accugas Limited customers other than through the Accugas network, unless the Company acquires assets which are contracted or mandated to supply gas to such customers.

5.1.6 *Relationship Agreement*

(a) Pursuant to the terms of the Accugas term sheet summarised at section 5.1 of this Part 14, a relationship agreement is intended to be entered into between SUGL, Universal's direct parent company (Stubb Creek Holdco), Accugas and Accugas Topco (the **"Relationship Agreement"**). The purpose of this agreement is to govern the terms of the parties' cooperation in relation to certain of the activities of Accugas. The Relationship Agreement is currently being negotiated and is expected to be entered into on the terms set out below. It is expected to become effective on the effective date of the Consolidated Upstream GSA, as set out in paragraph 5.1.7 of this Part 14.

(b) Pursuant to the Relationship Agreement, Accugas Limited and SUGL agree to jointly procure (at Accugas Limited's cost) the design, construction and installation of a metering station with chromatograph for each of the Uquo Field and the Stubb Creek Field (**"Metering Equipment"**) and a gas pipeline from the Stubb Creek Field to the Uquo CPF (**"SC Pipeline"**) to accommodate the volume of production from the Stubb Creek Field.

(c) The Metering Equipment and SC Pipeline will be owned by Accugas. The Metering Equipment is estimated to cost US$1.8 million for each field with a total of two metering facilities required (one for each of the Uquo Field and the Stubb Creek Field).

(d) The parties agree to jointly procure the design, construction and installation of compression units for each of the Uquo Field and the Stubb Creek Field (**"Compression Units"**). The Compression Units will be jointly owned by Accugas Limited and SUGL in proportion to the share of capital expenditure contributed by each party to the Compression Units' construction.

(e) The cost of the installation and construction of the Compression Unit at the Uquo Field shall be borne 75 per cent. by Accugas Limited and 25 per cent. by SUGL, save that if Accugas Limited demonstrates to the satisfaction of SUGL that the look-forward Accugas Holdco debt service cover ratio for any period in which the Compression Unit is being constructed is less than 1.1:1.0 then SUGL shall bear such additional cost required for the look forward debt service cover ratio to be 1.1:1.0, subject to a maximum cost to SUGL of no more than 50 per cent. of such costs.

(f) The cost of the installation and construction of the Compression Unit at the Stubb Creek Field shall be borne by Accugas Limited and SUGL in reverse proportions to the capital expenditure split in relation to the Compression Unit at the Uquo Field.

(g) The production of gas volumes in the Uquo Field which have been identified in the CPR at the date of the Relationship Agreement will be dedicated to supply the downstream customers of Accugas Limited. There is no obligation for the Enlarged Group to develop gas production from the Stubb Creek Field, but if this is developed then the gas volumes identified in the CPR at the date of the Relationship Agreement will be dedicated to supply the downstream customers of Accugas Limited.

(h) At the beginning of each year, the parties will agree when gas from the Stubb Creek Field is likely to be needed to allow Accugas to meet its commitments to its downstream customers based on the performance of the Uquo Field. If 30 months before gas from the Stubb Creek Field is expected to be needed, Universal has not yet reached FID on the gas development of the Stubb Creek Field, then Accugas Limited will have the right to request that Stubb Creek Holdco take all available steps to procure that Universal seek approval for and implement a gas development plan for the Stubb Creek Field, which will be implemented on a basis to be determined but shall include the following:

   (i) Accugas Limited shall fund the capital expenditure costs for the gas development of the Stubb Creek Field at a 15 per cent. interest rate;

   (ii) Universal shall take into consideration Accugas Limited's reasonable and timely comments on such gas development plan; and

   (iii) the intention is for the parties to jointly appoint a contractor and to jointly oversee the works.

(i) The parties to the agreement shall establish a joint marketing team to market the sale of gas by Accugas Limited to customers; SUGL will have the right to appoint a secondee to Accugas Limited for this purpose and will be involved in negotiations with downstream customers unless it will not or is not able to supply gas for such customers. Accugas Limited will not enter into any contract to supply gas that was provided by either SUGL or Universal without SUGL or Universal's respective consent.

(j) Any sale of gas by SUGL and/or Universal to Accugas Limited, other than pursuant to the Uquo or Stubb Creek GSA, shall be on substantially similar terms as the Consolidated GSA save that the contract price per Mscf pursuant to such new GSA shall be equal to the sum of:

   (i) $1.70; plus

   (ii) the weighted average percentage increase in achieved price pursuant to Accugas Limited's downstream contracts since the date of the Relationship Agreement,

   (iii) an amount equal to 50 per cent. of the amount by which the price agreed for the sale of gas by Accugas Limited to its buyers under a new downstream GSA is in excess of $3.4/Mscf, save where this does not allow each party to make an 18 per cent. internal rate of return on the project, in which case the parties will discuss the terms of the new supply contract in good faith.

(k) The Relationship Agreement allows the parties to enter into a tolling and transportation agreement providing the same economics as a new GSA described above, in relation to future gas sales to downstream customers.

(l) Accugas Limited will provide regular information to SUGL and Stubb Creek Holdco on its downstream gas sales and SUGL and Stubb Creek Holdco will provide Accugas with an annual CPR and with access to information to allow Accugas to prepare its own CPR.

5.1.7 *Consolidated GSA*

(a) Pursuant to the Accugas term sheet summarised at section 5.1 of this Part 14, SUGL, Frontier and Accugas Limited are to enter into a GSA for the sale of unprocessed gas by SUGL and Frontier to Accugas Limited (the **"Consolidated Upstream GSA"**) for onward supply by Accugas Limited to its downstream customers, including the Calabar PRG GSA, the Ibom Power GSA and the Unicem GSA (together the **"Existing Downstream GSAs"** and each an **"Existing Downstream GSA"**), as summarised in sections 5.3.2, 5.3.3 and 5.3.5 of this Part 14 respectively. This agreement will terminate and replace three existing upstream GSA between SUGL and Frontier (as sellers) and Accugas Limited (as buyer); the Company will not enter into the Implementation Agreement unless the Consolidated Upstream GSA has been agreed and executed in a form satisfactory to the Company. The summary below sets out the expected terms of the Consolidated Upstream GSA.

(b) The term of the Consolidated Upstream GSA is conditional on Accugas obtaining its lenders' consent to the agreement. If this condition precedent is not satisfied by the first anniversary of the Consolidated Upstream GSA the agreement shall terminate.

(c) During an initial phase from the effective date to 31 December 2023, the DCQ shall be 189.7 MMscf/d. After the initial period, the parties will agree on a reduced DCQ on the basis of the production capability of the Uquo Field.

(d) If the DCQ as defined in the Ibom Power GSA is increased, the DCQ of the Consolidated Upstream GSA shall increase but the increase shall not exceed 7 MMscf/d. If a DCQ as defined in an Existing Downstream GSA is reduced, the DCQ under the Consolidated Upstream GSA shall be reduced by the same amount. Additionally, if any of the Existing Downstream GSAs are terminated, the DCQ under the Consolidated Upstream GSA shall be reduced by the daily contract quantity under the terminated Existing Downstream GSA. The DCQ shall be reduced by up to 15 MMscf/d in the event that a regulatory authority requires SUGL and Frontier to supply the Alaoji Generation Company Limited from the Uquo Field.

(e) In the event Frontier and SUGL fail to deliver the DCQ, and Accugas Limited is liable for payment obligations pursuant to the Existing Downstream GSAs, Frontier and SUGL will bear their share of such costs subject to:

(i) a cap of 10 per cent. of the price of the Calabar PRG GSA multiplied by the volume of gas not delivered, in relation to payment obligations incurred under the Calabar PRG GSA;

(i) the parties will use their reasonable endeavours to amend the Ibom Power GSA and Unicem GSA to include a cap at 10 per cent. of the contract price pursuant to each such contract multiplied by the volume of gas not delivered; and

(ii) SUGL will have the conduct of any claims or potential claims in relation to such payment obligations.

(f) Accugas Limited has committed to a take or pay quantity equal to the aggregate quantity of natural gas which customers are obliged to take and pay for per month under the Existing Downstream GSAs. Accugas Limited is entitled to the part of the take or pay quantity which is not taken during a quarter, but which has been paid for by making a take or pay payment (**"Make-up Gas"**). This is to be taken free of charge providing it does not exceed the lower of: (i) the quantity Accugas Limited is obliged to deliver free of charge under an Existing Downstream GSA by virtue of take or pay provisions; and (ii) the sum of the Make-up Gas and the Make-Up Gas on the effective date less any gas already taken free of charge and any Make-Up Gas that arose more than three years before the start of that quarter.

(g) The contract price is $1.7 per Mscf plus an adjustment to reflect the inflation provisions under the Existing Downstream GSAs. Accugas Limited will procure that its downstream customers pay the amounts owed under the Existing Downstream GSA into an escrow account from which Frontier and SUGL will automatically be paid the amounts owed under the Consolidated Upstream GSA. In the event the downstream customers do not fulfil their payment obligations, Accugas Limited will not be liable to pay Frontier and SUGL but will have the obligation to enforce its rights under the Existing Downstream GSA as soon as it is entitled to do so, including through calling on letters of credit or guarantees. The pricing mechanics agreed in the Consolidated Upstream GSA will apply to new supply contracts for the supply of gas by Frontier and SUGL from the Uquo Field to Accugas for the on sale of gas to new downstream customers.

(h) Pursuant to the Consolidated Upstream GSA, neither Accugas Limited nor SUGL and Frontier shall be in breach of any of their obligations under the Consolidated Upstream GSA to the extent that their non-fulfilment occurs by virtue of a force majeure event which is not reasonably within their control (acting reasonably). Failure to make payments, financial loss or the inability to make profit from the sale or consumption of natural gas or insufficiency of reserves or resources do not constitute events of force majeure. Acts which primarily affect a third party (including contractors and subcontractors) may also qualify as a force majeure event if and to the extent that it is of a kind that, if it had occurred to SUGL, Frontier or Accugas Limited, would have constituted such an event.

(i) SUGL and Frontier may terminate the Consolidated Upstream GSA with immediate effect by notice if there is an act of insolvency in relation to Accugas except where Accugas Limited is not in default of any payment obligations under the Consolidated Upstream GSA and SUGL and Frontier are satisfied payment will continue under the Existing Downstream GSAs. Accugas Limited may terminate the Consolidated GSA by notice to SUGL and Frontier of not less than 90 days if there is an act of insolvency in relation to either Frontier or SUGL.

(j) No party is entitled to assign or transfer any rights or obligations under the Consolidated Upstream GSA without prior written approval of the other parties. SUGL and Frontier may assign or transfer any or all of their rights and obligations provided that they also assign their corresponding rights and interest in the Uquo Field to the assignee to enable the assignee and arrange for all the parties to the Consolidated Upstream GSA to execute a novation of the agreement.

5.1.8 *Termination of the Ekid Agreements and execution of the CPF JOA*

Ekid Gas Processing Company Limited (**"Ekid"**) is a company within the Seven Group which will not be part of the Enlarged Group. Ekid was established for the purpose of leasing, operating and eventually owning the Uquo CPF and the Ekid Agreements were entered into on 2 June 2010 to achieve this purpose. However, the Seven Group determined that this structure created an unnecessary tax liability and, since 2012 SUGL, Frontier and Accugas Limited have been treating the Ekid Agreements as terminated and acting in accordance with the terms of the CPF JOA (as defined below). The Company will not enter into the Implementation Agreement unless the Ekid Agreements have been terminated and the CPF JOA has been agreed and executed on terms satisfactory to the Company.

5.1.9 *CPF JOA*

(a) The draft central processing facility joint operating agreement (**"CPF JOA"**) sets out the terms relating to the operation and ownership of the Uquo CPF. The expected terms of the CPF JOA are summarised below. Notably, the CPF JOA processing charge is US$0.28 Mcf.

(b) Frontier is the designated operator of the Uquo CPF and is responsible for the maintenance and operation of the Uquo CPF. Frontier, as operator, is responsible for carrying out all joint operations approved by the joint operating committee and is to carry out its duties in accordance with "Good Industry Practice" (as defined in the agreement) on a no profit no loss basis, save that Frontier will be liable for its negligence, gross negligence, breach of laws, breach of compliance obligations and fraud. The operator can be removed for insolvency and related events, violation of applicable laws and regulations, material breach of the CPF JOA or ceasing to hold a participating interest in the Uquo Field.

(c) Until the achievement of a defined internal rate of return of 18 per cent. by Accugas, the parties' interest in the CPF JOA shall be Frontier (0 per cent.) and Accugas (100 per cent.). Following the achievement of the 18 per cent. internal rate of return, the parties shall each have an equal 50 per cent. interest in the Uquo CPF. Prior to the achievement of the 18 per cent. internal rate of return, Frontier also has the option to purchase a 50 per cent. interest in the Uquo CPF by making payment to Accugas which would amount to Accugas achieving the 18 per cent. internal rate of return. As at November 2017, the amount Frontier would need to pay for Accugas Limited to achieve an 18 per cent. IRR is US$449.9 million. Until the 18 per cent. internal rate of return has been achieved, Frontier may only transfer its interest in the CPF JOA to Accugas Limited. Furthermore, Accugas Limited is not entitled to withdraw from the CPF JOA until all amounts secured have been repaid and all encumbrances relating to third party financing in respect to the Uquo CPF have been released.

(d) A joint operating committee established in accordance with the CPF JOA shall comprise four members, two of whom shall be appointed by each of Frontier and Accugas Limited respectively. Accugas Limited is expected to have the right to appoint the chairman of the joint operating committee and the chairman is expected to have a casting vote for decisions of the joint operating committee.

(e) The CPF JOA contains typical reserved matters which require the prior written consent of both Frontier and Accugas Limited. These include, but are not limited to, the sale or disposal of any material interest in the Uquo CPF other than in accordance with the CPF JOA, the sale or disposal of all, or any material part of the location of the Uquo CPF or the approval of any operating plan, budget and maintenance programme for each calendar year.

(f) The occurrence of (without limitation) the following events, shall constitute a default under the CPF JOA:

    (i) either Frontier and/or Accugas Limited fails to pay when payment obligations fall due;

    (ii) any breach by Frontier and/or Accugas Limited of any CPF JOA representation or warranty which would reasonably be expected to have a material and adverse effect on the non-defaulting party; and

    (iii) a failure by either Frontier and/or Accugas Limited to perform certain CPF JOA obligations.

(g) Following any event of default, the non-defaulting party must give notice to the defaulting party of the default following which the defaulting party shall have a prescribed period to remedy the breach. During this period the defaulting party's rights under the CPF JOA are restricted. If the defaulting party fails to remedy its default following the non-defaulting party's default notice, the non-defaulting party shall have the option to require the defaulting party to sell and assign all its participating interest to the non-defaulting party at a prescribed discount to fair market value. It is expected that the CPF JOA will specify that, for so long as Frontier's participating interest in the CPF JOA is 0 per cent., the fair market value ascribed to Frontier's interest is US$1.00.

(h) In the event that a bona fide offer is made in writing to acquire substantially all of the Uquo CPF which is only conditional upon obtaining relevant government consent, a party that holds 75 per cent. or more of participating interest and wishes to accept the offer shall ask the remaining parties if they wish to participate in the sale and purchase of the Uquo CPF. A remaining party that declines such an offer shall have a right of pre-emption to acquire the property that is proposed to be sold to the bona fide offeror.

5.1.10 *Uquo Crude Oil Processing Agreement*

(i) The Company will not enter into the Implementation Agreement unless the Uquo Crude Oil Processing Agreement (**"COPA"**) has been agreed and executed on term satisfactory to the Company. The expected terms of the COPA are summarised below.

(j) Pursuant to the draft COPA, Accugas Limited will take delivery of the Uquo JV's raw crude oil, process it and redeliver to the Uquo JV processed crude oil in accordance with the specification set out therein.

(k) The agreement will have retrospective effect from 1 October 2012 and will continue to apply until the Uquo JV gives notice of the cessation of the production of hydrocarbons from the Uquo Field, unless terminated sooner in accordance standard termination provisions.

(l) After receiving the raw crude oil (including base sediments and water) from the Uquo JV, Accugas Limited is to: (i) strip out and receive title for associated gases, (ii) strip out condensate from the natural gases and add the condensate to the raw crude oil, and (iii) process and redeliver processed crude oil (excluding base sediments and water) to the Uquo JV.

(m) Title to the raw crude oil and condensate entering the Uquo CPF remain with the Uquo JV whilst at the risk of Accugas Limited between the delivery and redelivery point. Title and risk to the natural gas vests in Accugas Limited at the inlet to the Uquo CPF whilst title and risk to associated gas vests with Accugas Limited at delivery point.

(n) The processing tariff is US$4.25 per bbl (inclusive of tax) of processed crude oil, including condensate. Accugas Limited may increase this tariff as a result of modifications to the Uquo CPF, to recoup any increase in operating costs. Modifications to the Uquo CPF may be requested by the Uquo JV to improve its operation, efficiency or action; however Accugas Limited is not obliged to carry out such modifications if conflicts or other issues would arise with implementation. Accugas Limited is liable for taxes arising from ownership, operation and processing and the Uquo JV may deduct withholding tax from the tariff.

(o) The parties have provided typical warranties and representations and the agreement provides for knock for knock indemnities for claims arising from injury, death or property damage to each party's employees, directors, contracts and sub-contractors and that of their affiliates, as well as for damage to and pollution emanating from facilities and equipment upstream of the delivery point and related consequential losses

5.2 ***Agreements relating to the East Horizon Pipeline***

5.2.1 Pursuant to a share purchase and sale agreement dated 24 December 2013, SEIL purchased EHGC from Oando Plc and Ayotola Jagun (**"EHGC Sellers"**) for US$250 million less estimated net liabilities. Completion was subject to a number of conditions precedent, including entry by Accugas Limited, as an affiliate of SEIL, into a facility agreement to fund the acquisition. As part of its post-closing covenants, SEIL agreed to indemnify the EHGC Sellers against any damages incurred by them or any of their affiliates in respect of a parent company guarantee, until such time as the Sellers could obtain full and final release from the parent company guarantee.

5.2.2 By court order dated 14 December 2016 the Federal High Court at Lagos, Victoria approved the scheme of merger dated 27 October 2017 between EHGC and Accugas Limited. Under the scheme of merger, all assets, liabilities and undertakings, including contractual rights, real property, tax losses and unutilised capital allowances and intellectual property of EHGC would merge with those of Accugas Limited under the sanction of the court without any further act or deed. In consideration for the transfer, Accugas Limited issued additional shares to Exoro, and Exoro issued additional shares to SEIL. The effective date of the merger was agreed by the parties and declared in a joint declaration of the shareholders as 31 August 2017. As a result of the merger Accugas Limited has inherited EHGC's position in all agreements to which it had previously been party.

Pipeline MOU

5.2.3 A binding memorandum of understanding was entered into on 18 November 2014 between Nigerian Gas Company Limited (**"NGC"**), EHGC, Oando PLC and SEIL in relation to the East Horizon Pipeline (the **"Pipeline MOU"**).

5.2.4 Pursuant to the Pipeline MOU, NGC, EHGC and SEIL agreed that EHGC would transfer 15 per cent. ownership of the East Horizon Pipeline to NGC in part satisfaction of a debt owed by EHGC to NGC under the terms of a gas sale and purchase agreement entered into on 30 December 2008 (**"NGC GSA"**) by NGC and Unicem, and which Unicem assigned to EHGC by deed of assignment dated 29 March 2007. The NGC GSA was ratified in December 2013 by NGC, Unicem and EHGC.

5.2.5 The original intent of the NGC GSA parties was that Unicem would construct the East Horizon Pipeline to transport gas purchased from NGC to Unicem. However, it was subsequently agreed that EHGC would construct the pipeline and supply gas to Unicem, so the GSA between NGC and Unicem was assigned by Unicem from NGC to EHGC and EHGC and Unicem entered into the Unicem GSA (as defined below).

5.2.6 The US$37.5 million owed by EHGC to NGC pursuant to the Pipeline MOU relates to capex recovery on the construction of the East Horizon Pipeline and gas sales under the assigned NGC GSA.

5.2.7 Under the Pipeline MOU, the parties agreed that the transfer of a 15 per cent. interest in the East Horizon Pipeline to NGC who would discharge the Naira equivalent of US$37.5 million (NGN 5,801,250,000.00) owed by EHGC to NGC (pursuant to the NGC GSA), with such amount constituting capital expenditure recovery on the construction of the East Horizon Pipeline and gas sales under the assigned NGC GSA.

5.2.8 The parties agreed that a further amount of NGN 991,413,138 would be paid to NGC by Oando and NGN 539,358,163 would be paid by SEIL to NGC in satisfaction of EHGC's payment obligations to NGC under the NGC GSA.

5.2.9 Pursuant to the Pipeline MOU, all claims that NGC, EHGC and SEIL may have against each other relating to the acquisition by SEIL of EHGC or relating to the East Horizon Pipeline will be resolved by the proposed transfer by EHGC to NGC of 15 per cent. ownership in the East Horizon Pipeline pursuant to the Ownership Agreement (as defined below). However, the Pipeline MOU and the Ownership Agreement does not in any way prejudice EHGC's or NGC's rights under the NGC GSA, whether accruing before, on or after 31 August 2014, including NGC's rights to recover any outstanding payments that may be due to NGC in relation to the supply of gas under the NGC GSA.

Ownership Agreement

5.2.10 Pursuant to the terms of the Pipeline MOU, an ownership agreement was entered into between EHGC, NGC and SEIL on 18 November 2014 (the **"Ownership Agreement"**), to give effect to the transfer of the 15 per cent. ownership interest in the East Horizon Pipeline agreed under the Pipeline MOU.

5.2.11 The consideration for this transfer will be the release by NGC of its entitlement to recover the Naira equivalent of US$37.5 million in capital expenditure recovery costs and gas sales from the East Horizon Pipeline pursuant to the terms of the Pipeline MOU (as described above). In addition, EHGC is required to account for and pay to NGC all amounts received by EHGC in the period between signing the Ownership Agreement and completion and which relate to the ownership interest to be transferred, and indemnify NGC for any actual loss suffered as a result of environmental liability arising under or in connection with NGC's interest prior to completion (capped at US$18.75 million).

5.2.12 Completion under the Ownership Agreement is subject to a number of conditions which have not yet been satisfied. In particular, completion under the Ownership Agreement is subject to the execution of a pipeline maintenance agreement between EHGC, NGC and SEIL in relation to the East Horizon Pipeline (the **"PMA"**); negotiations between NGC and EHGC (now Accugas) remain ongoing. The long stop date for the satisfaction of the Ownership Agreement conditions has been extended several times and is currently 31 December 2017.

5.2.13 EHGC and SEIL are not permitted to sell, trade, relinquish, assign or otherwise create or agree to create any encumbrance over the NGC's interest, the pipeline or any part thereof. No party may trade, sell, assign or otherwise dispose of its participating interests in the pipeline under the Ownership Agreement pending completion. If a party (transferor) desires to transfer all or a portion of its participating interests in the pipeline, the transferor must give the other party (offeree) written notice of their intention to transfer (offer notice). The offeree shall have 20 business days following the notice date to provide an offer to purchase all of the transfer interest at a purchase price and on terms and conditions no less favourable than in the offer notice (purchase notice). If the transferor does not receive a purchase notice within 20 business days of the offer notice, the offeree is deemed to have declined to purchase the transfer interest and the transferor shall be entitled to transfer all (but not less than all) of the transfer interest to a third party purchaser.

PMA

5.2.14 The PMA (which is currently in draft form) sets out the terms for the management of the East Horizon Pipeline once it is in shared ownership between EHGC and NGC. Pursuant to the terms of the latest draft of the PMA:

(a) EHGC will be designated as operator of the East Horizon Pipeline on a no profit, no loss basis;

(b) each of EHGC and NGC will be entitled to capacity on the East Horizon Pipeline in proportion to their respective participating interest; such capacity can be sublet to the other participant or to a third party shipper. A party subletting its capacity will remain liable for any loss or damage to the East Horizon Pipeline caused by the third party shipper;

(c) where a party wishes to sublet all or part of its capacity entitlement, the other party will have a right of first refusal in relation to such capacity. In the event of proposed subletting of capacity to a third party shipper, the other party will have a right to match the third party shipper's terms and sublet the capacity on such terms;

(d) each of the participants will be charged a tariff in proportion to its participating interest in the East Horizon Pipeline, made up of a capacity charge and a commodity charge, which are calculated to cover the operating costs of the pipeline. However additional amounts are recoverable from the participants in proportion to their interests if the tariff is insufficient;

(e) SEIL is to provide a performance guarantee for EHGC's obligations as operator, and will indemnify the participants for EHGC's failure to perform its obligations as operator. The PMA will need to be amended to change the entity providing this guarantee; and

(f) it should be noted that a non-defaulting party may terminate the PMA where the other party, EHGC as operator or SEIL makes an assignment for the benefit of its creditors or enters into insolvency proceedings. If it is contemplated that the PMA be entered into prior to the completion of the Transaction, this provision PMA will need to be amended to allow for the Transaction and the related restructuring of loans, including the restructuring of Accugas' loans.

Each of the Pipeline MOU, the Ownership Agreement and the PMA are governed by the laws of the federal Republic of Nigeria.

5.3 ***Gas Sale and Purchase Agreements***

5.3.1 *Calabar PRG GSA*

(a) On 8 December 2011, Accugas Limited entered into a natural GSA with Calabar Electricity Generation Company Limited (now Calabar Generation Company Limited (**"CGCL"**), the Calabar NIPP power station's owner and operator, and CGCL's parent company, Niger Delta Power Holding Company Limited (**"NDPHC"**), to supply natural gas to CGCL

(**"Calabar PRG GSA"**). The Calabar PRG GSA was amended on 20 February 2013 via a side letter and became effective on 22 September 2017.

(b) There was a delay in building Accugas Limited's facilities under the Calabar PRG GSA so on 10 November 2014, the parties entered into an interim GSA for Accugas Limited to supply natural gas to CGCL via the East Horizon Pipeline until the facilities could be built. On 12 May 2017, the parties executed an amendment and restatement of the Calabar PRG GSA. The conditions precedent for this agreement were satisfied on 15 September 2017.

(c) The term of the agreement is 20 years from the start date. Provided Accugas Limited's facilities were constructed, tested, commissioned and ready to deliver quantities of natural gas to the delivery point when all conditions precedent were satisfied, the start date occurred 5 business days later, being 22 September 2017. First deliveries under the Calabar PRG GSA occurred on 22 September 2017.

(d) Under the Calabar PRG GSA, the daily contract quantity is 131.0 MMscfpd and the annual contract quantity is 131MMscfpd multiplied by the number of days in the relevant year (**"ACQ"**). Accugas Limited is contracted to supply the gas volumes nominated, being between zero and 150MMscfpd, capped at a maximum of 150MMscfpd multiplied by 365 in any given year. CGCL has committed to a take-or-pay obligation equivalent to 80 per cent. of 1/12th of the ACQ for the relevant year, less certain deductions set forth in the Calabar PRG GSA. Subject to the terms of the Calabar PRG GSA, CGCL can require any gas paid for but not received, is supplied as make-up gas at a later date, for which purpose CGCL may extend the term of the Calabar PRG GSA for a further 18 months.

(e) The contract price is $3.16 per MMBtu for the first year, to be increased progressively over the first seven years of the contract to US$4.74/ MMBtu (indexed annually by reference to US CPI and Nigerian CPI). Either party is entitled to seek a review of the contract price if, as a result of a change in law or any hindrance of government or other act or failure to act by any government claiming jurisdiction over the agreement, that party suffers a material adverse financial impact in any contract year.

(f) All payments under the agreement are to be made: (a) in the Naira currency using the applicable sell rate for the conversion of US$ to Naira published by the Central Bank of Nigeria on the business day immediately prior to the date of payment, or in the event that such rate is not published by the Central Bank of Nigeria, the interbank rate published on the FMDQ's website; or (b) at the option of CGCL, provided no laws prohibit this, in US$.

(g) The agreement can be terminated by CGCL by 30 days' notice to Accugas Limited if given prior to the start date, or by 180 days' notice thereafter if Accugas Limited, among other things: (i) abandons construction or operation of the facilities required to deliver gas to the delivery point; (ii) due to a force majeure event, fails to make available for delivery of 75 per cent. of the ACQ over a continuous 24 month period (provided that the volumes properly nominated by the buyer during each contract year of that period exceed 75 per cent. of the ACQ); (iii) fails to make available for delivery in any contract year 50 per cent. of the ACQ (provided that during that contract year the quantities of gas that are properly nominated by CGCL exceed 50 per cent. of the ACQ or 50 per cent. of the aggregate of the properly nominated quantities in such contract year); or (iv) suffers an insolvency event which is defined to include an assignment or general arrangement for the benefit of creditors. The agreement can also be terminated with immediate effect by CGCL where CGCL's power purchase agreement is terminated due to an event of force majeure.

(h) Accugas Limited may terminate the agreement by 30 days' notice to CGCL if given prior to the start date, or by 180 days' notice thereafter, if CGCL, among other things: (i) abandons construction or operation of the Calabar NIPP power station and the connecting pipeline; (ii) due to a force majeure event, is unable to take delivery of at least 75 per cent. of the ACQ over a 24 month period; (iii) fails to take delivery in any contract year of 50 per cent. of the aggregate of properly nominated quantities of gas; (iv) nominates zero quantities of natural gas for a period of 45 continuous days or 90 day in aggregate during any contract year, for reasons other than force majeure (and without Accugas Limited's consent); (v) suffers an insolvency event; or (vi) diverts the natural gas to facilities other than the Calabar NIPP power station, without the consent of Accugas Limited.

(i) Force majeure under the Calabar PRG GSA includes force majeure which primarily affects a third party where that force majeure prevents, impedes or delays CGCL or Accugas Limited's performance under the agreement.

(j) Where CGCL fails to pay amounts due pursuant to the agreement, interest at 5 per cent. plus three month LIBOR is applicable on all amounts due, and Accugas Limited is entitled to make a claim under the letter of credit provided in accordance with the terms of the Support Agreement (see "PRG agreements" section below). If the amount remains unpaid by either CGCL or the provider of the credit support, Accugas Limited is entitled to suspend deliveries under the agreement on 10 days' notice until such time as payment is made. If deliveries remain suspended in this manner for 60 consecutive days, Accugas Limited will have the right to terminate the agreement.

(k) Except in relation to permitted assignments to affiliates, the parties shall not assign all or any part of their rights and obligations under the agreement without the prior written consent of the other parties. CGCL and Accugas Limited may their rights under the agreement to a bank or other financial entity for the purpose of providing financing in connection with their respective facilities subject to the terms of the Support Agreement (see "PRG agreements" section below).

(l) CGCL must provide a letter of credit from an acceptable financial institution and as supported by the International Development Association's partial risk guarantee throughout the term of the agreement, in accordance with the terms of the Support Agreement (see "PRG agreements" section below).

(m) The agreement can be terminated by Accugas Limited in the event of an insolvency event affecting whichever of NDPHC or Nigerian Bulk Electricity Trading Plc (**"NBET"**) is then the party providing credit support for the agreement in accordance with the terms of the Support Agreement (see "PRG agreements" section below).

(n) Any change of control of CGCL requires Accugas Limited's prior written consent; prior to any change of control, alternative credit support must be provided to Accugas Limited to Accugas Limited's satisfaction determined at its sole discretion. However, it is recognised that CGCL and NDPHC are engaged in a process of privatisation, for which consent is explicitly given; credit support in the context of the privatisation is dealt with pursuant to the Support Agreement (see "PRG agreements" section below).

(o) The Calabar PRG GSA is governed by the laws of the federal Republic of Nigeria.

5.3.2 *PRG Agreements*

(a) The Calabar PRG GSA is ultimately supported by a partial risk guarantee from the International Development Association; however, this is not triggered immediately and a network of contracts has been put in place as set out below.

(b) Pursuant to the support agreement between NDPHC, CGCL, Accugas Limited and NBET dated 12 May 2017 (**"Support Agreement"**), NDPHC is to procure a letter of credit for Accugas Limited in relation to the amounts payable by CGCL under the Calabar PRG GSA, which letter of credit will be supported by a the International Development Association's partial risk guarantee pursuant to the guarantee agreement (see below). The Support Agreement specifies that when NDPHC is privatised, NBET will replace NDPHC as the guarantor for CGCL under the Calabar PRG GSA, being the party required to provide credit support for the Calabar PRG GSA. This is to ensure that the International Development Association's partial risk guarantee is always linked to credit support provided by a state owned entity. The fees for the letter of credit issued pursuant to the Support Agreement are to be paid by Accugas Limited. There is a 90 day moratorium period from the effective date of the letter of credit during which and in respect of which Accugas Limited will not be able to make demands for payment pursuant to the letter of credit. The letter of credit is to be provided by JP Morgan Chase Bank N.A., London Branch, or a substitute bank which must be a bank meeting the eligibility criteria, including a minimum of a "Long Term Issues Rating" of A2 by Moody's Investor Services, Inc, a "Foreign Company Long Term Issuer Default Rating" of "A" from Fitch Ratings Ltd and a "Foreign Long Term Issuer Credit Rating" of "A" by Standard and Poor's Financial Services LLC. The Support Agreement cannot be assigned by the parties except concurrently with the assignment of the Calabar PRG GSA and subject to the written consent of the other parties and the International Development Association.

(c) Pursuant to the project agreement between Accugas Limited and the International Development Association dated 14 June 2017, Accugas Limited agrees to pay the International Development Association's fees relating to the provision of the partial risk guarantee, being an annual fee of 0.75 per cent. of the maximum amount of the letter of credit applicable for the relevant period, together with one-off fees of 0.15 per cent. and 0.50 per cent. of the maximum amount of the letter of credit as initiation and processing fees.

(d) In order to monitor Accugas Limited's compliance with its obligation under the project agreement, Accugas Limited agrees to allow inspections of its pipelines and facilities by the International Development Association on reasonable notice. Accugas Limited must also keep (and allow the International Development Association access to) reports and information relating to gas deliveries pursuant to the Calabar PRG GSA, monthly invoices in relation to the same, information on payments made and defaults pursuant to the Calabar PRG GSA and demands under the Calabar PRG GSA.

(e) Accugas Limited also makes of the following covenants to the International Development Association:

  (i) no material change to the letter of credit or any other agreement related to the Support Agreement or Calabar PRG GSA without the International Development Association's prior written consent;

  (ii) co-operate in good faith with the International Development Association in relation to any breaches notified by the International Development Association;

  (iii) not engage in sanctionable practices (being corrupt practices, collusive practices, coercive practices or obstructive practices, each as defined in the agreement) in relation to the supply of gas pursuant to the Calabar PRG GSA;

  (iv) not engage or enter into contracts with debarred persons, being a person or entity which is ineligible to be awarded a World Bank financed contract;

  (v) to execute, operate and maintain the project with due diligence and efficiency and comply with its material obligations under the agreements relating to the Calabar PRG GSA;

  (vi) to implement and maintain policies and procedures to monitor compliance with environmental and social laws, a resettlement action plan and environmental impact assessments;

  (vii) keep the International Development Association informed of payment and default notices or demands pursuant to the Calabar PRG GSA and Support Agreement;

  (viii) not assign its rights, interests, covenants or obligations under this agreement, the Support Agreement or the letter of credit without the International Development Association's prior written consent (not to be unreasonably delayed);

  (ix) to notify the International Development Association of its application for or receipt of permits or licences for new oil wells or gas gathering or treatment facilities in the Uquo Field area and develop any such new wells or facilities in compliance with environmental and social laws; and

(x) to ensure compliance by its employees, agents, contractors and sub-contractors with environmental and social laws in relation to the supply of gas for the Calabar PRG GSA.

(f) In the event Accugas Limited breaches its representations, covenants or other obligations, the International Development Association can suspend its guarantee's coverage of the letter of credit on 45 days' notice. In the event Accugas Limited fails to make payments due within six business days, breaches its obligations relating to sanctionable practices, debarred persons, or in the event the guarantee of the letter of credit is suspended for a period of 180 days or longer, the International Development Association is entitled to terminate its guarantee.

(g) Accugas Limited has agreed to indemnify the International Development Association for, *inter alia*, any claims or liabilities incurred as a result of a representation, warranty, covenant or obligation of Accugas Limited under the agreement and all reasonable costs and expenses incurred in the enforcement of its rights or the enforcement of the letter of credit bank's rights, or the amendment of or a waiver or consent under the agreement.

(h) There is a guarantee agreement between the International Development Association and JP Morgan dated 14 June 2017 under which the International Development Association guarantees any amounts outstanding under the letter of credit to be issued by JP Morgan to NDPHC or NBET, as applicable, pursuant to the Support Agreement.

(i) By an indemnity agreement between the State of Nigeria and the International Development Association, the State of Nigeria agrees to indemnify the International Development Association for payments made pursuant to the guarantee agreement above.

(j) Pursuant to a cooperation agreement between the International Development Association and NDPHC dated 14 June 2017, NDPHC gives a number of warranties and covenants for the benefit of International Development Association and agrees to indemnify International Development Association for its losses pursuant to this agreement.

(k) Pursuant to a cooperation agreement between the International Development Association and NBET dated 14 June 2017, NBET gives a number of warranties and covenants for the benefit of International Development Association and agrees to indemnify International Development Association for its losses pursuant to this agreement.

(l) Pursuant to a reimbursement and credit agreement dated 15 May 2017 between NDPHC and JP Morgan and NBET, NDPHC and NBET, as applicable, agree to reimburse JP Morgan for amounts advanced under the credit support provided under the Calabar PRG GSA, with interest.

5.3.3 *Ibom Power GSA*

(a) On 15 May 2009, SEPL (as seller) and Ibom Power (as buyer) entered into a gas purchase and sales agreement, whereby SEPL agreed to supply processed gas to Ibom Power, as operator of the Ibom Power station (the **"Ibom Power GSA"**). On 4 June 2010, SEPL transferred its rights, liabilities, duties and obligations under the Ibom Power GSA to Accugas Limited via a deed of amendment, replacement and novation, and the Ibom Power GSA was amended and restated on the same day. The term of the Ibom Power GSA is ten years from the date of first commercial supply of gas (which occurred on 1 January 2014), subject to any extension mutually agreed between the parties.

(b) Delivery was initially on a take or pay basis for 100 per cent. of the ACQ being 43,500MMBtu multiplied by the number of days in the contract year, less certain deductions set out in the Ibom Power GSA. The Minimum and Maximum Daily Quantities were both 43,000MMBtupd. Under an addendum to the Ibom Power GSA executed on 26 April 2016 and effective from 1 April 2016, the Daily Contract Quantity was reduced to 20,000MMBtu and the Maximum Daily Quantity ("**MDQ**") became 27,000MMBtupd. Under the Ibom Power GSA, Ibom Power agrees to accept and pay for, or to pay for if not taken, the monthly equivalent of 80 per cent. of the MDQ, less certain deductions set forth in the Ibom Power GSA (including an Ibom Power force majeure and up to twelve days of Ibom Power outages). Ibom Power has an option to increase the MDQ to 43,500MMBtu (**"Increased DCQ"**) with a take-or-pay obligation of 80 per cent. of the Increased DCQ. The parties agree to discuss in good faith increasing the DCQ and MDQ to meet Ibom Power's requirements in Phase 2 of its developments, which will occur when the power generation capacity of Ibom Power's facilities reaches 685MW. Initially, the contract price for the gas was the higher of: (i) the fixed price, being a price of $0.40 per MMBtu plus a subsidy of $1.60 payable by the Akwa Ibom State Government to deliver to Accugas Limited a price of $2.00 per MMBtu (converted to Naira at the buying rate published on the Central Bank of Nigeria website for the invoice date); or, (ii) the last price, being the fixed price adjusted annually on the anniversary of the first supply date by the average US CPI for the preceding 12 months. By an addendum dated 1 August 2016, the parties agreed a new price of $3.30MMBtu, however, this price increase has yet to come into force, and is only expected to do so once regulatory approval from the Nigerian Electricity Regulatory Commission has been granted and the Settlement Agreement (as defined below) becomes effective.

(c) The Ibom Power GSA provides that Ibom Power pay an advance of $63.5 million for future gas deliveries. The Ibom Settlement Agreement as summarised in section 5.3.4 of this Part 14 provides for the payment of outstanding amounts in accordance with a payment plan.

(d) Accugas Limited repays the advance payment to Ibom Power by the provision of gas by way of credit in respect of the full amount invoiced for each month following the first supply date until the value of gas invoiced to Ibom Power equals 50 per cent. of the advance payment, and thereafter by way of credit of a Naira amount equal to $294,028 in respect of each invoice for each month until the aggregate credits invoiced to Ibom Power from Accugas Limited, during the contract period, shall equal the advance payment.

(e) The Ibom Power GSA requires Ibom Power to provide a guarantee from the Akwa Ibom State Government in respect of its obligations under the agreement and in accordance with the provisions set out therein. Ibom Power has provided an executed guarantee from the Akwa Ibom State Government dated 24 June 2010 (the **"Akwa Guarantee"**), for the Naira equivalent of $2.4 million to be set aside in an escrow account for 60 days, each month. In the event of a breach by Ibom Power of any of its obligations in the agreement, Accugas Limited has recourse to the Akwa Guarantee and is entitled to demand payment under the Akwa Guarantee for immediate payment of all unpaid amounts together with such payments as are required to recover any other losses suffered in respect of the breach or to demand the performance of any other obligation breached by Ibom Power.

(f) The Ibom Power GSA can be terminated by Accugas Limited upon ten days' written notice in the case of an event of default, as defined in the agreement, by Ibom Power or by the Akwa Ibom State government under its Akwa Guarantee. There are no reciprocal termination rights for Ibom Power. Save for permitted affiliates, the parties are not permitted to assign all or any part of their rights and obligations under the agreement without the prior written consent of the other parties. However, Ibom Power is not required to obtain the prior written consent of Accugas Limited in the event of a full or partial assignment of the agreement by Ibom Power for the purposes of obtaining financing for the construction of the Ibom Power station in Akwa Ibom State.

5.3.4 *Ibom Power Settlement Agreement*

(a) Accugas Limited, Ibom Power and Akwa Ibom State Government entered into a settlement agreement on 1 August 2016 (the **"Ibom Power Settlement Agreement"**) to settle outstanding legacy issues relating to the ownership of the facilities and land usage rights, as well as overdue payments owed by Ibom Power to Accugas Limited pursuant to the Ibom Power GSA.

(b) Pursuant to the Ibom Power Settlement Agreement, it was agreed that such issues would be resolved as follows:

(i) the start date was 4 March 2013 and Accugas Limited waived and discharged Ibom Power from all sums that would otherwise have been due to it from the period 4 March 2013 to 31 December 2013. Payment for gas was agreed to commence 1 January 2014;

(ii) $5,247,480.92 due and outstanding from Ibom Power to Accugas Limited would be payable under a payment plan;

(iii) the contract price in the Ibom Power GSA would be increased to US$3.30/MMBtu;

(iv) Accugas Limited would remit to the Government of Akwa Ibom State, as guarantor, a 66.67 per cent. share of the difference between the initial contract price and the new contract price, save in the event Ibom Power has not fulfilled its payment obligations. This shall be paid in the first instance by reducing the unpaid invoices due by Ibom Power to Accugas Limited in respect of gas sold pursuant to the Ibom Power GSA;

(v) the historic make up gas balanced due to Ibom Power pursuant to the Ibom Power GSA will be reconciled; and

(vi) the Akwa Ibom State Government would provide Accugas Limited with a lease for a term of not less than 99 years (with an option to review) in respect of land on which Accugas Limited's gas receiving facility and other infrastructure is located.

(c) The Ibom Power Settlement Agreement has not yet come into effect as certain conditions precedent have not yet been fulfilled, these include regulatory approval for the gas price increase, approval by Accugas Limited's lenders, a withdrawal of all existing claims and a payment plan to be submitted by Ibom Power and accepted by Accugas Limited.

5.3.5 *Unicem GSA*

(a) By a gas sale agreement dated 18 April 2007 (as amended on 5 January 2012 and 28 November 2016) between EHGC (as seller) and Unicem (as buyer) (the **"Unicem GSA"**), EHGC agreed to sell and Unicem agreed to purchase gas for Unicem's cement plant in Cross River State, Nigeria. The term of the agreement is 20 years from 5 January 2012, subject a period for delivery of make-up gas following expiry of the term not exceeding the 22nd anniversary of the Date of First Gas Delivery. The Unicem GSA may be renewed by mutual agreement by the parties.

(b) Under the Unicem GSA, Unicem agreed to take and/or pay for a minimum of 80 per cent. of the annual contract quantity for the relevant year. The annual contract quantity was of 230,000,000 SCM of gas (and the daily contract quantity was plus or minus ten per cent. of 710,000 SCM/D) until 1 July 2016 and thereafter, the annual contract quantity became 4,000,000,000 SCM (and the daily contract quantity, plus or minus ten per cent. of 1,420,000 SCM/D). Until 2014, the contract price for the gas was based on a schedule of domestic gas prices issued by the MPR and adopted by the parties. Until 30 June 2016, the gas price was $6.63 per Mscf and following the ramp-up period which ended in November 2016, for the remainder of the contract, $5.0 per Mscf (payable in Naira at the monthly average of the official CBN rate as currently published by CBN on its website as calculated on the date of invoicing).

(c) If a party reasonably believes there has been a change in economic circumstances relating to the Unicem GSA and in consequence thereof that party has suffered significant economic hardship (other than where such hardship is or was caused by the failure of that party to act in accordance with the standards of a reasonable and prudent operator, or where the hardship was caused by changes in indebtedness or financing costs), the party may give notice to the other party and the parties shall meet in good faith to review the contract price.

(d) The Unicem GSA may be terminated, by either party by notice in writing with immediate effect if any act of insolvency occurs in relation to the other party. Unicem may also terminate, inter alios, for convenience on one month's notice. However, where Unicem terminates for convenience, Unicem shall be liable to pay the seller a termination fee in the sum of $200 million, which sum shall be reduced by $10 million for each contract year which has elapsed since 2012 prior to such termination and $27,397 for each day that has elapsed since the last day of the contract year immediately preceding the effective date of the termination. Where the agreement is so terminated, EHGC may be required by Unicem to assign, without cost, all its rights and obligations under the NGC GSA. Unicem shall then be required to enter into a gas transportation, operations and maintenance agreement with EHGC for the length of the term of the NGC GSA, under which Unicem shall pay EHGC a fee of $0.70-$0.90 per Mscf for the transportation/delivery of gas to Unicem.

(e) Unicem's obligations under the Unicem GSA are guaranteed to a value of 1,450,000,000 Naira (approximately $4 million) under a bank guarantee in favour of Accugas Limited executed by Standard Chartered Bank of Nigeria Limited and dated 24th October 2017. The guaranteed sum is payable upon written demand signed by an authorised representative of Accugas Limited stating that the customer has failed to make any due payments under the contract. The guarantee expires on 24 October 2018. The guarantee cannot be transferred or assigned without the prior written consent of Standard Chartered Bank of Nigeria Limited.

5.3.6 *NGC GSA*

(a) NGC and Unicem entered into the NGC GSA on 30 December 2008, which Unicem assigned to EHGC by deed of assignment dated 29 March 2007 (becoming effective on the date the NGC GSA became effective). The NGC GSA was ratified in December 2013 by NGC, Unicem and EHGC.

(b) The original intent of the parties to the NGC GSA was that Unicem would, via a subsidiary of Oando called Gaslink, construct the East Horizon Pipeline to transport gas purchased from NGC to Unicem. However, Oando subsequently incorporated EHGC and the parties agreed that EHGC would construct the pipeline and supply gas to Unicem. The NGC GSA between NGC and Unicem was assigned by Unicem to EHGC and EHGC and Unicem entered into the Unicem GSA.

(c) Under the NGC GSA, NGC agreed to sell natural gas to EHGC for a period of 20 years from the date of execution, which period may be extended by agreement between the parties. EHGC is subject to a take-or-pay obligation of 80 per cent. of the ACQ of 7,260MMscf (22MMscfd). EHGC may take make-up gas for a further 12 months after expiry of the agreement. The price is a percentage of the prevailing NNPC ex-depot price of low pour fuel oil, increasing from 60 per cent. to 80 per cent. during the first five years of the term.

(d) Where EHGC diverts or re-sells the gas purchased under the agreement for purposes other than those intended at Unicem's facilities without the consent of NGC, EHGC must pay for the gas at a price double the applicable gas price under the agreement or double the prevailing gas price in the sector, whichever is higher. This provision applies to EHGC as it is reselling the gas purchased under the NGC GSA to Unicem under the Unicem GSA.

(e) If EHGC fails to pay an amount owing under the NGC GSA and that failure continues for more than 180 days, NGC has a right to terminate. There is a limitation of liability of 5 per cent. of the value of the ACQ in which the cause of action resulting in the said liability arises.

(f) Assignment requires the consent of each party to the NGC GSA.

PART 15

SUMMARY OF THE KEY TERMS OF THE SAVANNAH PSCs

This is a summary of key terms of the Savannah PSCs and is not designed to be an exhaustive treatment of the subject. Definitions for this Part 15 are set out herein.

1. Exploration and Exploitation Process and Timelines

Below is a description of the process and timelines under the PSC for development of the Contractual Areas governed by the PSCs.

Stage 1 – Exploration phase *(Articles 33 to 58 of the Law of 2007, Articles 122 to 158 of the Implementing Decree, Articles 8 to 11 of the PSCs)*

Pursuant to Article 8.1 of the Savannah PSCs, the State shall issue the Contractor an Exclusive Exploration Authorisation via an order by the Minister of Energy and Petroleum, 30 days following the signature of the PSC. Pursuant to Articles 39.1 of the Law of 2007 and 8.1 of the Savannah PSCs, the term of the said Exclusive Exploration Authorisation shall be four years as from the date of issuance, i.e. the date of Official Gazette publication (hereafter referred to as "the Initial Period" of the Issuance Order). Pursuant to Article 39.2 of the Law of 2007 and to Article 8.2 of the Savannah PSCs, the Exclusive Exploration Authorisation shall be renewed on request of the Contractor, two times only, and for a period requested by the Contractor in his renewal application, provided that each renewal period does not exceed two years and the whole duration of the Exclusive Exploration Authorisation (including the Initial Period and the renewal periods) does not exceed eight years (without prejudice to any extension in accordance with Article 10.3 of the Savannah PSCs).

The Contractor's renewal application shall indicate the area that the Contractor wishes to retain, which shall not exceed 50 per cent. of the surface area defined for the current Exclusive Exploration Authorisation (Article 41 of the Law of 2007 and Article 129 of the Implementing Decree of 2007), but with deduction made for any Contractual Areas for which an Exclusive Exploitation Authorisation will be in effect as at the expiration date for the current period.

According to Article 9 of the R1/R2 PSC as amended by Amendment n°2, during the Initial Period, the Contractor undertakes to execute the following Minimum Works Programme: (i) acquisition, processing and interpretation of 500 km^2 of new 3D seismic profiles; and (ii) drilling of two Exploration Wells to a minimum depth of 2,500 metres.

If a renewal exploration period is granted (each of which is up to two years in length) in respect of the R1/R2 PSC, the Contractor shall implement the following Minimum Works Programme:

- For the first renewal period: (i) acquisition, processing and interpretation of 250 km^2 of new 3D seismic profiles; and (ii) drilling of 1 Exploration Well to a minimum depth of 2,500 metres.
- For the second renewal period, the drilling of 1 Exploration Well to a minimum depth of 2,500 metres.

According to Article 9.1 of the R3/R4 PSC as amended by Amendment n°2, during the Initial Period, the Contractor undertakes to execute the following Minimum Works Programme: (i) acquisition, processing and interpretation of 750 square kilometres of new 3D seismic profiles; and (ii) drilling of three Exploration Wells to a minimum depth of 2,500 metres.

If a renewal exploration period is granted (each of which is up to two years in length) in respect of the R3/R4 PSC, the Contractor shall implement the following Minimum Works Programme:

- For the first renewal period: (i) acquisition, processing and interpretation of 250 square kilometres of new 3D seismic profiles; and (ii) drilling of 1 Exploration Well to a minimum depth of 2,500 metres.
- For the second renewal period, the drilling of 1 Exploration Well to a minimum depth of 2,500 metres.

If the Contractor fails to satisfy the Minimum Works Programme obligation either at the Initial Period or if due to the total renunciation or the withdrawal of the EEA during these periods, the works have not achieved the minimum undertakings required for that period, the Contractor shall pay the Government, as a lump sum payment, within 30 Days after the end of the period concerned, the effective date of the total renunciation or the date of the withdrawal of the Exclusive Exploration Authorisation, a penalty equivalent to (for both the R1/R2 PSC and R3/R4 PSC): (i) US$1,000,000 for each undrilled well; (ii) US$800 for each kilometer of 2D seismic profiles not acquired, processed or interpreted[69]; and (ii) US$2,500 per square kilometer of 3D seismic profiles not acquired, processed or interpreted.

Stage 2 – Discovery/Feasibility/Commercial Deposit phase *(Article 10 of the Savannah PSCs)*

As per Article 10.1 of the Savannah PSCs, the Contractor must notify the Government as soon as possible of any Discovery made within the Contractual Exploration Area and no later than two (2) Working Days from this Discovery. Within 30 Days of the Discovery, the Contractor shall send a report concerning this Discovery to the Management Committee containing all available information about this Discovery.

Pursuant to Article 10.2.1 of the Savannah PSCs, no later than 90 Days after the notification of the Discovery and if the Contractor considers that this Discovery should be assessed, it shall submit the planned programme for the Feasibility Study and the corresponding Budget to the Management Committee.

On completion of the Feasibility Study, the decision to proceed with the Development Operations of the discovered Oilfield, that shall serve as the declaration confirming the existence of a Commercial Oilfield, shall be taken in the Management Committee by the Contractor, as provided under Article 10.4 of the Savannah PSCs.

Stage 3 – Exploitation phase *(Articles 59 to 80 of the Law of 2007, Articles 159 to 200 of the Implementing Decree, Articles 12 to 20 of the Savannah PSCs)*

In accordance with Article 12.1 of the Savannah PSCs, if the Contractor concludes that an Oilfield is a Commercial Oilfield, or that several Oilfields are Commercial Oilfields, it may request an Exclusive Exploitation Authorisation and shall be entitled to obtain a separate Exclusive Exploitation Authorisation for each Commercial Oilfield or a joint one for more than one of these Commercial Oilfields, at the Contractor's choice. Pursuant to Article 12.6 of the Savannah PSCs, the Exclusive Exploitation Authorisation shall be issued by a Decree approved by the Council of Ministers, for the period requested by the Contractor, and this period cannot exceed 25 years from the date of its issuance.

Pursuant to Article 12.7 of the Savannah PSCs, the Contractor is entitled to apply for a maximum ten-year extension of the period of each Exclusive Exploitation Authorisation and such extension will be granted if the Contractor has met its contractual obligations under the Exclusive Exploitation Authorisation and has demonstrated that the relevant hydrocarbon deposits will remain commercially exploitable beyond the initial period of Exclusive Exploitation Authorisation. This application for an extension must be submitted at least 2 years prior to the expiration of the initial period of the Exclusive Exploitation Authorisation.

Government of Niger participation *(Article 65 of the Law of 2007, Article 14 of the Savannah PSCs)*

Pursuant to Article 14.1 of the Savannah PSCs, on issuance of any Exclusive Exploitation Authorisation, the Government, shall be entitled, to require the transfer of a participating interest up to 20 per cent. in the rights and obligations arising from such Exclusive Exploitation Authorisation either directly to or through a Public Corporation.

If the Government decides to take such a participating interest in the Exclusive Exploitation Authorisation, the Government must carry out the following acts to the extent of its participating interest in the Exclusive Exploitation Authorisation (Article 14.4 of the Savannah PSCs):

- Reimburse immediately without interest, its proportional share of the Petroleum Costs relating to the Exploration Operations and to the preparation and negotiation of the PSC; and
- Contribute an equivalent amount with the other Joint Holders of the Authorisation to the financing of the Petroleum Costs relating to the Development, Exploitation and Abandonment Operations from the date of the issuance of the Exclusive Exploitation Authorisation.

[69] This penalty is provided, for the R3 & R4 PSC, in the said PSC, and for the R1 & R2 PSC, in its Amendment n°1. However, this penalty is no more relevant as under their Amendments n°2, the R1 & R2 PSC and the R3 & R4 PSC respectively no longer contain an obligation to acquire, process and interprete 2D seismic profiles (only 3D seismic profiles).

All costs for which the Government is liable to reimburse or finance shall be effected as advances of the other Joint Holders apart from the Government or the Public Corporation up to the Public Participation Interests of 20 per cent., in the case of the R1/R2 PSC, and 15 per cent., in the case of R3/R4 PSC. Such advances shall not be interests-bearing.

2. Economics of the PSC

2.1. *Ad Valorem Tax (i.e. Royalty)*

(Article 113 of the Law of 2007, Articles 40 and 43 of the Savannah PSCs)

Pursuant to Article 40 of the PSC, once commercial production has begun, the Contractor is required to pay the Government an Ad Valorem Tax at a rate of 12.5 per cent. for crude oil and 2.5 per cent. for natural gas (following the subtraction of transportation costs to market). The Ad Valorem Tax shall be wholly or partly paid either in cash or in kind (Article 43.1 of the Savannah PSCs).

2.2. *Cost Recovery*

(Article 41 of the Savannah PSCs)

Article 41 of the Savannah PSCs provides that a portion of the Net Production of Hydrocarbons, net of Ad Valorem Tax and originating from each Contractual Exploitation Area during the Calendar Year shall be allocated to the reimbursement of the Petroleum Costs actually borne by the Contractor in relation to the Contractual Exploitation Area concerned, within the limit of the Cost Stop that represents 70 per cent. of the Net Production of Hydrocarbons, net of Ad Valorem Tax.

Pursuant to Article 41.2.1 of the Savannah PSCs, unrecovered costs in each Calendar Year are carried forward to the subsequent Calendar Year until total recovery or expiry of the Contract.

2.3. *Profit sharing*

(Article 108 of the Law of 2007, Article 42 of the PSC)

According to Article 42 of the Savannah PSCs, the Net Production of Hydrocarbons from each Contractual Exploitation Area, less the Ad Valorem Tax and the portion deducted as Cost Oil (referred to as **"Profit Oil"**) is allocated between the Government of Niger and the Contractor in accordance with an "R-Factor" determined each quarter for each Exclusive Exploration Authorisation using the following formula:

$$\text{R-Factor} = \frac{W^{(1)} - X^{(2)}}{Y^{(3)} + Z^{(4)}}$$

Notes:

(1) "W" means the total of the amount of the share of Crude Oil at the Ex-Field Market Price applicable for each Quarter from the start of production, and, where applicable, of the share of Natural Gas to which the Contractor is entitled as Cost Oil and Profit Oil for the Quarter in question, from the date of the issue of the Exclusive Exploitation Authorisation up till the last Day of the Quarter preceding the Quarter for which the R-Factor is determined.

(2) "X" means the total of the costs of the Exploitation Operations incurred by the Contractor from the date of the issue of the Exclusive Exploitation Authorisation until the last Day of the Quarter preceding the Quarter for which the R-Factor is determined.

(3) "Y" means the total of the costs of the Development Operations for the Contractual Exploitation Area concerned incurred by the Contractor from the date of the issue of the Exclusive Exploitation Authorisation up till the last Day of the Quarter preceding the Quarter for which the R-Factor is Determined

(4) "Z" means the total of the Exploration Costs allocated to this Contractual Exploitation Area in accordance with Article 41 above.

Profit Oil is shared between the Government of Niger and the Contractor according to the following scale, depending on R-factor:

R-factor	*Percentage of Profit Oil to the benefit of the Contractor*	*Percentage of Profit Oil to the benefit of the Government of Niger*
Less than or equal to 1	60%	40%
Between 1 and 1.5	55%	45%
Between 1.5 and 2	50%	50%
Greater than 2	45%	55%

2.4. ***Infrastructure***

(Article 5.3 of the Savannah PSCs)

Pursuant to Article 3 of the Savannah PSCs, the Contractor is entitled to use the public installations required for the Petroleum Operations, including airports, roads, building sites and other similar installations, subject to the payment of fees due for such use, where applicable.

In addition, the Contractor is entitled to execute or have executed on these lands, all construction works and infrastructure required or necessary for the Petroleum Operations, including the setup of markers and boundary markers, the construction of the installations required for the storage of materials, equipment, products and waste, and for ballasting and the elimination of pollution and the transport of materials, equipment and extracted products, without prejudice to the observance of the rules relating to the execution of construction works and infrastructure applicable in the protection areas that may be established around built-up areas, cultivated areas, plantations, water points, archaeological sites, cultural sites and burial sites, by the Nigerien authorities.

2.5. ***Access to pipeline and rights for the construction of pipelines***

In accordance with the provisions of Article 83 of the Petroleum Code, Article 19 and the Annex F of the Savannah PSCs, the Exclusive Exploitation Authorisations issued to Savannah Niger shall entitle the latter to transport, within the territory of Niger, its share of the products to the storage, processing, loading, major consumption or delivery points or have it so transported.

If Savannah Niger determines that such transport requires the construction and operation of one or more Pipelines transport systems for hydrocarbons, the Government must, subject to the compliance by the Transport Contractor with the formalities and conditions provided to this effect by Petroleum Legislation (1) sign a transport agreement with the Transport Contractor and (2) issue an Internal Transport Authorisation to the latter.

Savannah Niger may also request to be authorised to transport the hydrocarbons produced by a pipelines transport system constructed by another person without having priority but the granting of such authorisation shall be automatic if all the conditions required by Petroleum Legislation are met. The transport tariff relating to a pipelines transport system for hydrocarbons must be agreed between the Transport Contractor and the Government. In particular, this tariff must (a) include a utilisation coefficient for the installations (b) take into account the operating costs of this pipelines transport system, (c) take into account the depreciation of installations and pipelines, the distances and (d) enable the Transport Contractor to achieve an internal rate of return (IRR) not exceeding 12.5 per cent. over the whole duration of the related Transport Operations.

Concerning international transportation of hydrocarbons produced, the PSC guarantees that the Government and Savannah Niger will cooperate mutually so as to negotiate and bring to finalisation international transport agreements with the foreign states concerned. The Government will make its best efforts so that the Transport Contractor can obtain all authorisations or licences required by the related foreign State relative to the export transport system.

2.6. ***Abandonment***

(Article 37 of the Savannah PSCs)

Article 37.2 of the Savannah PSCs states that if the Contractor estimates that 75 per cent. in total of the proven reserves of an Exclusive Exploitation Authorisation shall be produced during the next Calendar Year, it shall submit the Abandonment Operations programme that it proposes to execute within the Contractual Exploitation Area relating to the Exclusive Exploitation Authorisation concerned to the Government no later than 31st August of the current Calendar Year, with a plan for the restoration of the site, a programme of the proposed works, and a detailed estimate of all costs associated with these Abandonment Operations.

Pursuant to Article 37.3.1 of the PSC, the annual amount of the provision for Abandonment Operations made by the Contractor at the end of a Calendar Year for each Contractual Exploitation Area shall be calculated as follows:

$$\text{Contribution to Abandonment Fund} = \frac{(\text{ECAO}^{(1)} - \text{TPAO}^{(2)}) \times \text{TPH}^{(3)}}{\text{TPR}^{(4)}}$$

Notes:

(1) **"ECAO"** means the estimated costs of the Abandonment Operations.

(2) **"TPAO"** means the total provisions made for Abandonment Operations related to the same Exclusive Exploitation Authorisation and effected during the Calendar Years preceding the one for which the provision is calculated.

(3) **"TPH"** means the total production of Hydrocarbons from the Contractual Exploitation Area for this Calendar Year.

(4) **"TPR"** means the total of the proven reserves developed and still to be produced at the beginning of this Calendar Year within the Contractual Exploitation Area in question.

2.7. ***Taxes*** *(Article 109 to 129 of the Law of 2007, Articles 224 to 230 of the Implementing Decree, Article 38 to 49 of the Savannah PSCs)*

- **Land royalties** *(Article 112 of the Law of 2007, Article 47 of the Savannah PSCs)*

  The Contractor must pay annual land royalties calculated in accordance with the following schedule (in XOF):

  (a) Exclusive Exploration Authorisation:

  First validity period: 500F/km²/year

  Second validity period: 1,500F/km²/year

  Third validity period: 2,500F/km²/year

  Extension: 5,000F/km²/year

  (b) Exclusive Exploitation Authorisation:

  First validity period: 1,500,000F/km²/year

  Second validity period: 2,000,000F/km²/year

- **Capital gains tax on Assets Transfer** (*Article 114.3 of the Law of 2007, Articles 147 to 150 and 189 to 192 of the Implementing Decree, Article 48 of the Savannah PSCs)*

  Pursuant to Article 48.1 of the Savannah PSCs, the capital gains resulting from the transfer of assets relating to an Authorisation executed by the Contractor or any of its constituent entities shall be subject to an exceptional 25 per cent. tax payable by the Assignor.

  As per Article 48.2 of the Savannah PSCs, the provisions of Article 48.1 shall not apply to capital gains on the transfer of materials, equipment and other items used for the execution of the Petroleum Operations.

As provided under Article 48.3 of the Savannah PSCs, the basis for the capital gains tax shall be the difference between:

- the price for the Assets Transfer on one hand, and
- the cost price of the assets concerned.

The transfer price is made up of the price actually received, in cash or in kind, less any reimbursement of advances to the Contractor for the asset concerned. Pursuant to Article 48.3.3 of the Savannah PSCs, notwithstanding the provisions above, the financial valuation of the Exploration Operations that the Assignee agrees to perform on behalf of the Assignor is not included in the sale price of the assets, provided that the relevant Exploration Operations are conducted after the date of the disposal of the Assets. Consequently, the financing of such costs by the Assignee shall not be subject to capital gains tax.

The cost price of the assets concerned shall be constituted by the Petroleum Costs relating to these assets not yet recovered, increased by the value of intangible assets not valued in these Petroleum Costs as at the date of the transfer, including all costs leading to the signing of the Contract and relating to the issue of an Authorisation, especially the unrecoverable share of the signature bonus.

Pursuant to Article 48.4 of the Savannah PSCs, the capital gains tax shall be paid by the Assignor within thirty (30) Days of the issue of the transfer authorisation. The Assets Transfer concerned shall only take effect from the submission of a declaration by the Contractor concerning the capital gain of the Assets Transfer, validated by the tax authorities of the Republic of Niger, and of the payment of the exceptional corresponding capital gains tax.

It shall be noted that pursuant to Article 48.2 of the Savannah PSCs, the transfer of Assets triggering capital gains tax shall be *"direct transfers of rights and obligations carried out by the Assignors: (i) either in the Authorisation concerned; or (ii) in the PSC in relation to all or part of the Authorisations issued to the Contractor*".

Consequently, in case of sale of shares of a parent company controlling the Niger entity holding the Assets, no capital gains tax shall apply in Niger.

- **General tax exemption** *(Article 123 of the Law of 2007, Article 49.1 of the Savannah PSCs)*

  Pursuant to Article 49.1.1 of the Savannah PSCs, apart from the fees stipulated in Article 110 of the Petroleum Code, the exceptional capital gains tax on Asset Transfers, the Ad Valorem Tax, the land royalties, the Government's share of Profit Oil, stamp duties and registration fees (except where an exception is stipulated in the PSC), and the provisions of Paragraph 49.4 of the Savannah PSCs related to withholdings, each of the Contractor's constituent entities shall be exempt from all taxes, deductions, charges, imposts and other obligatory contributions:

  - either by virtue of the activities executed in application of the Savannah PSCs; or
  - by virtue of the payments received or effected as part of the execution of the Savannah PSCs.

2.8. ***Liability***

(Article 6.5 of the Savannah PSCs)

Pursuant to Article 6.5 of the Savannah PSCs, within the limits of and in accordance with the modalities stipulated by the Savannah PSCs relating to the Contractor's liability and obligations in the conduct of the Petroleum Operations, and to the settlement of disputes, the Contractor must indemnify the Government for any direct damage caused to the Government imputable to the Contractor, its managers, employees or agents and the persons that it has substituted for the execution of the Contract.

The Contractor shall be solely liable for direct damage caused to Third Parties due to the Petroleum Operations or by the acts of its agents, employees or any other person that it may have substituted in the execution of the Contract. For the application of this paragraph, the Government shall be deemed to be a Third Party in relation to the damage caused to public works, buildings and other public property. This would also be the case in case of direct damage to the environment as soon as this damage exceeds the environmental impact level generally accepted in the international petroleum industry and by Petroleum Legislation.

2.9. ***Applicable Law***

(Article 58 of the Savannah PSCs)

Pursuant to Article 58.1 of the Savannah PSCs, the Petroleum Legislation and the PSC as well as principles of international law shall constitute the law of the Parties subject to (i) with respect to the conventional rules of international law, that they are not the result of international agreements that have not been duly ratified by the State and taking into account the reservations expressed by the State in the implementation of the said international agreement (ii) with respect to the other rules and principles of international law, the State has not demonstrated in one way or other, before the conclusion of the Contract, its intention to be bound by these rules.

As provided under Article 159 of the Law of 2007 and Article 58.2 of the Savannah PSCs, the Nigerien Government guarantees that the Contractor shall not be subject to a modification of the Petroleum Legislation or any existing legislation at the date of signing of the PSC without its prior consent whose effect shall be to:

- Directly or consequently increase the obligations and responsibilities imposed on the Contractor by the provisions of Petroleum Legislation or of this Contract immediately or in the future;
- Infringe the Contractor's economic and fiscal rights and advantages resulting from Petroleum Legislation and this Contract.

DEFINITIONS OF TERMS UNDER THE PSC

Abandonment Operations	The management, supervision and execution of the operations terminating in the definitive cessation of the exploitation of an Oilfield and the corresponding wells, wholly or partially, the Service Shutdown and Securing of the whole or a part of the Contractual Area concerned, and the restoration of sites, especially by the Dismantling of installations. The Abandonment Operations shall particularly include the preparation and updating of the abandonment plan, the definitive cessation of production operations, service shutdown of processing units, the Dismantling, transport and storage of materials, and the Engineering works associated with the execution of these operations.
Assessment Area	The area of the Contractual Exploration Area where the Contractor intends to carry out a Feasibility Study enabling the determination of the commercial character or lack thereof of any Oilfield discovered in this Contractual Area.
Assets Transfer	Direct transfer of rights and obligations carried out by the Assignor: (i) either in the Authorization concerned; or (ii) in the PSC in relation to all or part of the Authorizations issued to the Contractor.
Assignee	Any person who has acquired rights and obligations resulting from its Exclusive Exploration Authorization or from one or more Exclusive Exploitation Authorization(s) from any of the Contractor's constituent entities, entity including persons that have acquired these rights subsequent to the constitution of a guarantee or by subrogation or substitution of Lenders. The status of Assignee shall also be given to any person who has taken control of any of the Contractor's constituent entities or of a person succeeding in any way to all or part of the rights and obligations of such an entity.
Assignor	The Contractor or any of its constituent entities executing a transfer of assets relating to an Authorization.
Authorization	In the singular, as the case may be, any Exclusive Exploration Authorization or Exclusive Exploitation Authorization or Internal Transport Authorization issued by the Government in accordance with Petroleum Legislation. In the plural, at least two of these authorizations taken together.
Calendar Year	A period of twelve (12) consecutive months from 1 January to 31 December of the same year.
Commercial Oilfield	an Oilfield whose economic profitability and technical feasibility have been demonstrated by a Feasibility Study, and which the Contractor believes can be developed and exploited under economic conditions, in accordance with international petroleum industry practice.
Consortium	At any time, this is the group of companies or other legal entities formed, where applicable, subsequent to the conclusion of the Contract, whose members are joint holders of the Exclusive Exploration Authorisation or, where applicable, of an Exclusive Exploitation Authorisation, it being specified that any Assignee succeeding to all or part of the rights and obligations of one of the aforementioned companies or other entities in the Exclusive Exploration Authorisation or in any Exclusive Exploitation

	Authorisation shall become a member of the Consortium with respect to the Authorisation in which it participates.
Contract	The relevant PSC, its annexes and any amendments, substitutions, extension or renewal of these presents by agreement between the Parties. However, whenever reference is made to the Contract in an Annex, this term shall refer to this document solely.
Contractor	Savannah Petroleum Niger R1&R2 S.A. or the Consortium formed subsequent to the conclusion of this Contract or any Assignee succeeding to all the Contractor's constituent entities. Whenever any reference is made to any of the Contractor's constituent entities, this shall refer to Savannah Petroleum Niger R1&R2 S.A. or any entity constituting the Consortium or an Assignee succeeding to all the Contractor's constituent entities.
Contractual Area	In the singular, the Contractual Exploration Area or a Contractual Exploitation Area, as the case may be, and in the plural, at least two of these Contractual Areas taken together.
Contractual Exploitation Area	The area within an Exclusive Exploitation Authorization at any time.
Contractual Exploration Area	The area within the Exclusive Exploration Authorization at any time, after deduction of the areas surrendered by the Contractor, where applicable.
Cost Oil	The portion of the Net Production from an Exclusive Exploitation Authorization, net of the Ad Valorem Tax, allocated for the reimbursement of the Petroleum Costs actually incurred by the Contractor for the execution of the Petroleum Operations that are the object of the Contract.
Cost Stop	The maximum percentage of the Net Production of an Exclusive Exploitation Authorization, net of Ad Valorem Tax, that may be allocated for the reimbursement of Petroleum Costs for the Calendar Year, in accordance with the provisions of Article 41 of each of the Savannah PSCs.
Council of Ministers	The group of Ministers entitled to adopt the final version of the relevant PSC through the issuance of a decree, as provided under Article 125 of the Implementing Decree.
Crude Oil	Crude mineral oil, asphalt, ozokerite and other liquid Hydrocarbons in the natural state or obtained from Natural Gas by condensation or extraction, including Natural Gas condensates and liquids.
Current Legislation	Any law or Act with the same legal value, derived from an international treaty or agreement properly ratified by the Republic of Niger, any administrative regulatory or individual act, any case law in force in the Republic of Niger as at the Effective Date that is not contrary to Petroleum Legislation or the Contract, to which the Contractor is subject for all issues not governed by Petroleum Legislation or the Contract.
Default	The default invoked by the Government of Niger towards the Contractor and which shall entitle the State to terminate the Contract.
Delivery Point	Any point for the transfer of the ownership of the Hydrocarbons by the Contractor to its customers, stipulated by mutual agreement

	between the Parties, whether at the F.O.B. shipping point at the Port of Loading on the maritime coast or at any other point located within or outside of the Republic of Niger.
Development and Exploitation Plan	The plan submitted by the Contractor in accordance with the provisions of Article 12 of each of the Savannah PSCs.
Development Operations	All operations and activities undertaken by the Contractor in the event of the Discovery of a Commercial Oilfield and after the issue of an Exclusive Exploitation Authorization for the commencing production on this Oilfield. These operations particularly comprise the preparation of the Development and Exploitation Plan, the Drilling of development and exploitation wells, construction of installations and equipment, collection pipes, pipelines, factories and other infrastructure required for the production, storage and transport of Hydrocarbons (except for the works falling under the area of Transport Operations), and the preliminary works and production tests carried out prior to the commencement of the commercial production of Hydrocarbons.
Discovery	The discovery by the Contractor, during its Exploration Operations, of Hydrocarbons whose existence was unknown up till that time.
Dismantling	The operation consisting of the permanent disengagement from a Contractual Area and the recovery of pipes, connection cables, accessories and other equipment used for the Petroleum Operations.
Drilling	Preparatory works associated particularly with the selection of various options, observation of the course of the operations, identification and management of risks and responsibilities, the preliminary and detailed studies supporting each operations phase, the safety studies, the studies conducted for the construction of industrial installations, the Environmental Impact Studies, preparation of the documentation required by current legislation and regulations, implementation of the consultation processes, verification and evaluation by independent third parties commissioned by the Contractor.
Effective Date	The date on which the Contract comes into force as stipulated in Article 3 of each of the Savannah PSCs.
Engineering	Preparatory works associated particularly with the selection of various options, observation of the course of the operations, identification and management of risks and responsibilities, the preliminary and detailed studies supporting each operations phase, the safety studies, the studies conducted for the construction of industrial installations, the Environmental Impact Studies, preparation of the documentation required by current legislation and regulations, implementation of the consultation processes, verification and evaluation by independent third parties commissioned by the Contractor.
Environmental Impact Study	The study that the Contractor is obliged to carry out obtain the environmental certificate of conformity, under the terms of Article 36 of each of the Savannah PSCs.

Exclusive Exploitation Authorization	Any exclusive exploitation authorization issued to the Contractor in accordance with Petroleum Legislation and authorizing it to undertake Hydrocarbons Development Operations and Exploitation Operations in the corresponding Contractual Exploitation Area.
Exclusive Exploration Authorization	The exclusive exploration authorization as defined by the Petroleum Code, issued to the Contractor in accordance with the provisions of Petroleum Legislation and authorizing it to undertake Hydrocarbons Exploration Operations in the Contractual Exploration Area.
Ex-Field Market Price	The price of the Crude Oil from any Contractual Exploitation Area at the Measurement Point, determined in accordance with the provisions of Paragraph 39.1 of each of the Savannah PSCs.
Exploitation Operations	Exploitation activities, activities associated with the extraction and processing of Hydrocarbons for commercial purposes, particularly operations relating to the production, storage and evacuation of Hydrocarbons to the connection point to the Pipeline Transport System for Hydrocarbons and associated activities such as the abandonment of Oilfields, surface and subsurface installations, apart from the Development Operations carried out by virtue of the Exclusive Exploitation Authorization and in accordance with the modalities stipulated in the Contract.
Exploration Operations	The activities defined in Article 33 of the Petroleum Code carried out by virtue of the Exclusive Exploration Authorization and in accordance with the modalities stipulated in the Contract.
Feasibility Study	The evaluation and delimitation of an Oilfield within a Contractual Area and any economic and technical study enabling the establishment of the commercial character of the Oilfield or the absence thereof, as described more extensively in Paragraph 10.2 of the PSC.
F.O.B.	Freight on board.
Government or State	The Government of Republic of Niger.
Hydrocarbons	Crude Oil and Natural Gas.
Implementing Decree	Décret d' Application, the Decree No. 2007-082 of 28 March 2007, issued for the application of the Petroleum Code.
Initial Period	The first exploration period, i.e. the period of four (4) years from the date of issue of the Exclusive Exploration Authorization, i.e. the date of publication in the Official Gazette of the related Ministerial Order.
Internal Transport Authorization	Any internal transport authorization issued to the Transport Contractor in accordance with Petroleum Legislation and authorizing it to construct and operate a pipeline transport system for Hydrocarbons.
International Transport Agreements	The agreements and conventions concluded between the Governments and the governments of the territories in which any pipeline transport system for Hydrocarbons that must cross the territory of one or more third party countries shall be constructed and operated in order to organize this construction and operation and to define the status of the works and of the Transport Contractor.

Issuance Order	The order granting the Exclusive Exploration Authorization in accordance with the provisions of the Contract and Petroleum Legislation.
Joint Holder	Any entity which is a joint holder with others of the Exclusive Exploration Authorization and, where applicable, of an Exclusive Exploitation Authorization.
Law of 2007 or Petroleum Code	The Law n° 2007-01 dated 31 January 2007 laying down the Petroleum Code of the Republic of Niger.
Lenders	Persons participating in financing or refinancing of the Petroleum Operations, apart from contributions to capital, including any guarantor or underwriter of loans subscribed to this effect by the Contractor and all assignees, representatives, fiduciaries or companies affiliated to these persons.
Management Committee	The committee whose establishment, powers and operating modalities are stipulated in Article 23 of each of the Savannah PSCs.
Minimum Works Programme	The minimum works and expenses stipulated in Article 9 of each of the Savannah PSCs for each exploration period that the Contractor undertakes to execute.
Minister of Energy and Petroleum	The Minister representing the Government of Niger and acting for the purposes of the Contract by virtue of the powers conferred on him by Article 101 of the Law of 2007.
Natural Gas	Dry gas or wet gas, produced separately or in association with the Crude Oil and all other gaseous components extracted from the Wells.
Net Production	The total production of Hydrocarbons from a Contractual Exploitation Area less all water, all sediments produced and all quantities of Hydrocarbons re-injected into the Oilfield or Oilfields, used or lost during the Petroleum Operations.
Official Gazette	The Official Gazette of the Republic of Niger.
Oilfield	A geological structure impregnated with Hydrocarbons.
Parties	The Republic of Niger and Savannah Petroleum Niger R1/R2 S.A..
Petroleum Code	See "Law of 2007".
Petroleum Costs	All costs, charges and expenses incurred by the Contractor with a view to or as part of the execution of the Petroleum Operations stipulated in the Contract, and calculated according to the modalities of the accounting procedure in Annex B of each of the Savannah PSCs. These comprise: (a) costs of Exploration Operations; (b) costs of the Development Operations; (c) costs of the Exploitation Operations; (d) costs of the Abandonment Operations.
Petroleum Legislation	All of the legislation applicable to the area of petroleum in the Republic of Niger as at the date of this document, including the Petroleum Code and the Implementing Decree.

Petroleum Operations

Exploration Operations, Development Operations, Exploitation Operations, Abandonment Operations, including the activities relating to the construction and operation of transport systems within the Contractual Area or between Contractual Exploitation Areas or between the exploitation areas of the various Oilfields belonging to the same Contractual Exploitation Area, and including the Associated Activities undertaken by virtue of the Contract, with the exclusion of:

(a) activities relating to the refining of Hydrocarbons, and the storage and distribution of Petroleum Products; and

(b) the construction and operation of the Hydrocarbons Pipeline Transport System which shall be undertaken by virtue of an Internal Transport Authorisation and a Transport Agreement granted and concluded with the Transport Contractor, as the case may be.

Profit Oil

Net Production of Hydrocarbons from each Contractual Exploitation Area, less the Ad Valorem Tax and the portion deducted as Cost Oil determined in accordance with the provisions of Article 41 of each of the Savannah PSCs.

Public Corporation

Industrial or commercial public establishments, state-owned corporations or semi-public companies in the sense of Order No. 86-001 of 10th January 1986 concerning the general regime of public establishments, state-owned corporations and semi-public corporations or the subsequent texts concerning public or para-public enterprises, formed for the execution of one or more Petroleum Operations or empowered to execute such activities in accordance with the laws and regulations in force in the Republic of Niger.

Public Participating Interest

The participating interest of a maximum of twenty percent (20 per cent.) in the rights and obligations attached to the Exclusive Exploitation Authorization granted either directly to the Government, or through a Public Corporation.

Quarter

A period of three (3) consecutive months commencing on the first day of January, April, July and October of each Calendar Year.

R-Factor

The ratio determined in accordance with the provisions of Article 42 of each of the Savannah PSCs that shall act as the basis for the calculation of the share of Profit Oil to which the Parties are entitled.

Remediation Date

The deadline stipulated in the formal notice dispatched by the Government to the Contractor within which the Contractor shall remedy the Defaults invoked.

Service Shutdown and Securing

The operations comprising the movement of consumable materials and supplies that can be used for the Petroleum Operations, the emptying and cleaning of processing systems, the phased shutdown of general services and safety systems with the aim of securing the installation and preparing for Dismantling.

Third Party

Any person other than the Contractor, a shareholder, an affiliated company, an Assignee or any other person subrogated in the rights of the Contractor. Subcontractors that do not have the status of shareholder, affiliated company or Assignee shall also be classified as Third Parties under the Contract.

Transport Contractor	The company formed to act as the holder of one or more Internal Transport Authorizations and to carry out the Transport Operations.
Transport Operations	All operations relating to the Hydrocarbons pipeline transport system(s), particularly the operations related to design, assembly, construction, operation, management, maintenance, repair and upgrading.
Working Day	Any day deemed to be a working day in accordance with current legislation.

PART 16

CORPORATE GOVERNANCE

Corporate governance

The Board recognises its responsibility for the proper management of the Company and the importance of sound corporate governance commensurate with the size and nature of the Company and the interests of its shareholders. The Board is therefore committed to maintaining high standards of corporate governance. As an AIM-quoted company, Savannah Petroleum is not required to comply with a particular corporate governance regime. Nevertheless, the Directors recognise the value of the QCA Code and the Corporate Governance Code and the Company complies with their principles and provisions where relevant and appropriate, having regard to the size, current stage of development and resources of the Group and the direct cost of delivering effective corporate governance.

Set out below is a summary of the Company's proposed corporate governance structure and practices.

The Board

The Board is collectively responsible to the Shareholders for the effective oversight and long-term success of the Company. In addition to those matters required by the Companies Act 2006, the Board is also responsible for strategy, performance, capital structure, approval of key contracts and major capital investment plans, the framework for risk management and internal controls, governance matters and engaging with shareholders and other key stakeholders. The Board's full responsibilities are detailed in a formal schedule of matters reserved for its decision.

The Board has established a schedule of quarterly meetings, with additional meetings convened as required from time to time by the business of the Company. The Board and its Committees are supported by the Company Secretary in organising and circulating the papers for these meetings and with governance and statutory compliance matters. Board papers for each meeting are circulated at least five working days (where possible) prior to the Board meeting.

The Board addresses several recurring items at each board meeting. The key documentation that is prepared and submitted to the Board in the Board pack prior to meetings is described below:

- Financial updates;
- Technical updates;
- Operational and Health, Safety, Security and Environment updates;
- Updates on strategic projects;
- Corporate communications and investor relations updates; and
- Company Secretarial and Governance updates.

The roles of the Chairman and the Chief Executive

The roles of the Chairman and the Chief Executive are separate, with a clear division of responsibilities. The separation of authority enhances the independent oversight of the executive management by the Board and helps to ensure that no one individual on the Board has unfettered authority. The Board is chaired by Steve Jenkins, a Non-Executive Director who met the independence criteria set out in the Corporate Governance Code on appointment. The Chairman is responsible for setting the Board's agenda, ensuring that adequate time is available for discussion of all agenda items and encouraging a particular focus on strategic issues. The Chairman promotes a culture of openness and debate within the Board, where the views of all Directors and the actions of the executive management are challenged. The Chairmen of the Board's Committees perform the same role for their Committees.

Andrew Knott is the Chief Executive Officer. Through delegation from the Board, he is responsible for managing the day to day operations and the implementation of the strategy of the Company.

Composition, qualification and independence of the Board

Following the restoration of the Existing Ordinary Shares to trading, the Board will comprise eight Directors, being one Non-Executive Chairman, five Non Executive Directors and two Executive Directors (the CEO and CFO). The Chairman and Non-Executive Directors are all deemed to be independent (taking into account the factors set out in the Corporate Governance Code) in character and judgement and free from relationships or circumstances which could affect their judgement. Please refer to paragraph 15 of this Part 1 and paragraphs 6 to 7 of Part 13 of this document for more information in relation to each Director.

The Directors' biographies illustrate the wide range and high caliber of their skills and experience. These include appropriate industry, operational, risk management, financial, legal and regulatory experience and, in the case of the Non-Executive Directors, the willingness and ability to provide robust and objective challenge to the views and assumptions of the executive management and other Directors.

A formal recruitment process for the appointment of Michael Wachtel and David Clarkson was established in the earlier stages of the Transaction. As part of the recruitment process, the Remuneration and Nomination Committee sought to identify the appropriate skill sets required by the Company to enable the business' progression. Operational and legal skills were identified as key requirements. The Company engaged a third party adviser to supplement their internal process and sought benchmarking and referencing support through this third party. A number of candidates were identified through this process and those shortlisted underwent a formal interview and vetting process prior to the selection of the preferred candidates.

Sir Stephen O'Brien was known to the Company since its inception, owing to his previous work in Africa on behalf of the British Government and the United Nations. He was identified by the Company as a candidate for the role of Non-Executive Vice Chairman of the Company after he stepped down from his last role at the United Nations, owing to his particular set of skills and experience.

The Directors bring wide range and high calibre of skills and experience brought to bear on matters considered by the Board. These include appropriate industry, regulatory, financial, operational and risk management experience and, in the case of the Non-Executive Directors, the willingness and ability to provide robust and objective challenge to the views and assumptions of senior management and other Directors.

The Board has considered and reviewed the independence and effectiveness of each Non-Executive Director, taking into account the factors set out in the Corporate Governance Code that might, or could appear to affect, a director's judgement and therefore their independence. The Corporate Governance Code suggests that Directors' participation in their company's share option or performance related scheme could, or could be seen to, compromise their independence. The Board considers that the performance-related shares and options awarded to the Non-Executive Directors encourage the alignment of their interests with those of the Company's shareholders and are not material enough to compromise their independence of character and judgement.

Going forward, the Board will continue to undertake its annual evaluation of the Board and its committees, including their balance of skills, experience, knowledge and independence. To date, the evaluation has been conducted based on a tailored, high level questionnaire, structured to provide the Directors with an opportunity to express their views, followed by a discussion at the Board. The Chairman will also continue to offer the Non-Executive directors the opportunity to meet regularly, as necessary, in the absence of the CEO, CFO and other members of management.

The CFO has been appointed on an interim basis. The Board is committed to running a due nomination process to ensure that the candidate who undertakes this role in the longer term has the appropriate skills and experience commensurate with the Enlarged Group's requirements which will be monitored by the Board on an ongoing basis.

Appointments, including appointments to the Board and senior management positions will continue to be made on merit, taking account of the balance of skills, experience and knowledge required.

Directors' Training

The Chairman, with the support of the Company's NOMAD, legal advisers and the Company Secretary, is responsible for the induction of new Directors and ongoing development of all Directors. All current Directors of the Company were provided with training in respect of their legal, regulatory and governance responsibilities and obligations in accordance with the UK regulatory regime at the time of their appointment. The Proposed Directors will be provided with this training prior to the restoration to trading of the Existing Ordinary Shares and will also undertake a comprehensive Board induction programme tailored to their individual needs and requirements. This will include, as necessary, face-to-face meetings with executive management and operational site visits to orientate and familiarise them with the organisation, business, strategy, commercial objectives and key risks.

Briefings on issues relating to legal, regulatory and corporate governance matters are provided by the Company Secretary at the quarterly Board meetings or communicated via email to the management team if more appropriate.

The training needs of the Directors are periodically discussed at Board meetings and additional training is available on request, where appropriate, so that Directors can update their skills and knowledge as applicable.

All current Directors have received training on the EU Market Abuse Regulation and this has also been cascaded down to all employees who may come into possession of inside information or become aware of information that could potentially be inside information, to ensure they are aware of how to handle it. The Proposed Directors will receive training on the EU Market Abuse Regulation prior to the restoration to trading of the Existing Ordinary Shares.

Board Committees

The Board delegates certain responsibilities to its Committees, so that it can operate efficiently and give an appropriate level of attention and consideration to relevant matters. The Board has an Audit and Risk Committee and a combined Remuneration and Nomination Committee and will also establish a Health, Safety, Security and Environment Committee and a Compliance Committee. The Board's Committees operate within a scope and remit defined by specific terms of reference determined by the Board. The composition and role of each Committee is summarised below.

The Board and its committees are provided with high quality information on a timely basis in order to facilitate the proper assessment of the matters under consideration and the Non-Executive Directors are provided with access to all the information they require and to external advice where necessary.

The Role of the Audit and Risk Committee

The Audit and Risk Committee is chaired by Mark Iannotti and its other members are David Clarkson, Sir Stephen O'Brien and Michael Wachtel. All members will be independent Non-Executive Directors. Mark Iannotti is considered by the Board to have recent and relevant financial experience and the Committee as a whole has competence relevant to the sector in which the Company operates, as required by the Corporate Governance Code. If required, at the request of the Chairman of the Committee, the Chief Executive Officer, the Chief Financial Officer and other members of the senior management team are also invited to attend meetings.

The terms of reference of the Committee reflect the current statutory requirements and best practice appropriate to a company of Savannah's size, nature and stage of development. Under these terms of reference, the role of the Committee is to assist the Board in discharging its responsibilities with regard to monitoring the integrity of the Group's financial reporting. It reviews reports from the external auditor relating to the accounts, oversees the relationship with the external auditor, and makes recommendations to the Board regarding their appointment. The Committee is also responsible for reviewing the adequacy and effectiveness of the Group's internal controls and risk management systems and reporting its findings to the Board. The ultimate responsibility for reviewing and approving the Annual and half-yearly report and accounts remains with the Board.

The Audit and Risk Committee is required to meet not less than three times a year at appropriate times in the financial reporting and audit cycle and whenever is necessary to fulfil its responsibilities. The Audit and Risk Committee addresses a number of recurring items, including:

- Review of the full year and half-year results, including the underlying accounting issues and judgements, the processes underpinning the preparation of those documents and the information supporting the statements in relation to going concern and disclosure of information to the external auditor;
- Consideration of the external auditor's annual work plan and reports on the full and half-year results;
- review and, if appropriate, recommendation of the re-appointment of the external auditor for the Group;
- review of the need to establish an internal audit function; and
- assessment of progress made in relation to enhancing the internal controls and risk management systems and procedures within the Group.

Any significant findings raised by the External Auditors during their review of the half-yearly results or audit of the full year results are reviewed and discussed by the Audit and Risk Committee and reported or referred to the Board as appropriate.

Savannah is committed to achieving the high standards of conduct and accountability and a structure which allows employees to openly report legitimate concerns regarding improprieties in financial reporting by non-compliance with applicable laws, regulations or Group policies, danger to health and safety, damage to the environment or other matters that may harm the reputation of the Group. Any of these can be reported without fear or penalty or punishment. The Group's Anti-Corruption and Money Laundering Policy is circulated to all Company employees and is provided to any new joiners and consultants employed by the Group, to ensure it is embedded across the organisation. All Company employees are required to confirm receipt of the policy and undergo anti-corruption and money laundering training on an annual basis.

Where there is an overlap of responsibilities between the Audit and Risk Committee, the Health, Safety, Security and Environment Committee, and the Compliance Committee, the respective committee chairs shall have the discretion to agree the most appropriate committee to fulfil any obligation.

The terms of reference of the Audit and Risk Committee are available on the Company's website.

The Role of the Remuneration and Nomination Committee

The Remuneration and Nomination Committee is chaired by David Jamison and its other members are Steve Jenkins and Mark Iannotti. All members of the Committee are independent Non-Executive Directors. If required, at the request of the Chairman of the Committee, the Chief Executive Officer and members of the senior management team are also invited to attend meetings.

The terms of reference of the Remuneration and Nomination Committee reflect the current statutory requirements and best practice appropriate to the Company's size, nature and stage of development. Under these terms of reference, the Committee is primarily responsible for determining and reviewing the terms and conditions of service (including remuneration) and termination of employment of executive Directors and senior employees and the grant of options implemented from time to time.

The Remuneration and Nomination Committee acknowledges the importance of orderly succession planning for board renewal and in relation to key members of the executive team. As a small company with a lean operating structure, it is currently envisaged that, should a board member or key member of the executive team be unable to fulfil their duties for a period of time, one of the other directors with the most appropriate experience would step in to perform the role on an interim basis until a longer term solution was identified. Going forward, the Committee will seek to develop and review on a regular basis the succession planning for both the Board and key members of management, based on the FRC's feedback on this area published to date and the updated Guidance on Board Effectiveness when published.

The Remuneration and Nomination Committee is required to meet at least twice a year. Its terms of reference are available on the Company's website.

In due course, if additional directors are appointed. The Board may consider establishing separate Remuneration and Nomination Committees in accordance with the Corporate Governance Code; however, at present, the Board considers that the creation of an additional committee would be unnecessarily burdensome in the context of the overall size and complexity of the business.

The Role of the Health, Safety, Security and Environment Committee

The Health, Safety, Security and Environment Committee will be chaired by David Clarkson and its other members will be Steve Jenkins and Sir Stephen O'Brien. All members will be independent Non-Executive Directors of the Company.

The purpose of the Committee will be to ensure that the Company has an appropriate framework of policies, procedures, systems and controls in place in relation to the health, safety, security and environmental risks arising from the operations of the Group, to promote the appropriate culture, behaviours and decisions and to communicate the Board's commitment to these matters to the Group's staff, contractors and other stakeholders.

In addition, the Committee will be responsible overseeing compliance with the above framework and receiving reports on all serious accidents and fatalities within the Group, together with corresponding actions taken by management. The Committee will also oversee the effectiveness of this framework and its impact, as well as the quality and integrity of any reporting to external stakeholders regarding health, safety, security and environmental matters.

Where there is an overlap of responsibilities between the Health, Safety, Security and Environment Committee, the Compliance Committee and the Audit and Risk Committee, the respective committee chairs shall have the discretion to agree the most appropriate committee to fulfil any obligation.

The Committee will meet three times a year. Its terms of reference will be available on the Company's website.

The Role of the Compliance Committee

The Compliance Committee will be chaired by Michael Wachtel and its other members will be David Clarkson, David Jameson and Mark Iannotti. All members will be independent Non-Executive Directors of the Company.

The purpose of the Committee will be to support the Board in fulfilling its responsibilities to promote and oversee compliance with all applicable legal and regulatory obligations across all the business activities of the Group and to communicate the Board's commitment to compliance to the Group's staff, contractors and other stakeholders. Under its terms of reference, the Committee will be responsible for overseeing the development and implementation of, and compliance with, a strategy and framework of policies, procedures, systems and controls to identify, assess, manage and report on compliance matters. The areas of focus include prevention of bribery, corruption, money-laundering and countering of terrorist financing, the prevention and detection of non-financial fraud, tax evasion and facilitation of tax evasion; and monitoring of business relationships, including dealings with public officials, agents, intermediaries, political consultants and advisers. The Committee will also be responsible for overseeing the Group's whistleblowing arrangements and monitoring the investigations and actions taken in relation to any allegations of impropriety.

The Committee will regularly review the compliance risks arising from the Company's operations and regularly assess the adequacy and effectiveness of the above framework.

Where there is an overlap of responsibilities between the Compliance Committee, the Health, Safety, Security and Environment Committee and the Audit and Risk Committee, the respective committee chairs shall have the discretion to agree the most appropriate committee to fulfil any obligation.

The Committee will meet three times a year. Its terms of reference will be available on the Company's website.

Share Dealing Code

The Company has adopted a share dealing policy which sets out the requirements and procedures for the Board and applicable employee's dealings in any of its AIM securities in accordance with the provisions of MAR and of the AIM Rules.

Whistleblowing and anti-bribery and anti-corruption policy

Savannah is committed to achieving high standards of conduct and accountability and a structure which allows employees to openly report legitimate concerns regarding improprieties in financial reporting by non-compliance with applicable laws, regulations or Group policies, danger to health and safety, damage to the environment or other matters that may harm the reputation of the Group. Any of these can be reported without fear of penalty or punishment.

The Company has adopted an anti-corruption and bribery policy which applies to the Board and all employees of the Enlarged Group. It generally sets out their responsibilities in observing and upholding a zero-tolerance position on bribery and corruption in all jurisdictions in which the Enlarged Group operates as well as providing guidance to those working for the Enlarged Group on how to recognise and deal with bribery and corruption issues and the potential consequences. The policy is circulated to all Group employees and is provided to any new joiners or consultants employed by the Group, to ensure it is embedded across the organisation. All Group employees are required to confirm receipt of the policy and undergo anti-corruption and money laundering training on an annual basis.

The Company expects all employees, suppliers, contractors and consultants to conduct their day-to-day business activities in a fair, honest and ethical manner, be aware of and refer to this policy in all of their business activities worldwide and to conduct business on the Company's behalf in compliance with it. Management at all levels are responsible for ensuring that those reporting to them, internally and externally, are made aware of and understand this policy.

Risk Management & Internal Controls

The Board has overall responsibility for establishing and maintaining the Group's system of internal controls and risk management and reviewing its effectiveness. As with any successful company, delivering the Company's business objectives will involve taking considered risks. The Group's internal controls and risk management framework has been designed to assist the Board in making better, more informed decisions with a view to creating and protecting shareholder value.

These internal controls will be re-assessed on an ongoing basis, in particular before Completion, in line with management's integration plans for the Enlarged Group.

The Board recognises that such a system has its limitations. Internal controls can only provide reasonable, not absolute, assurance against material misstatement or loss. The purpose of risk management is to manage rather than eliminate risk entirely and involves Directors and senior management exercising judgement.

The internal control framework within which the Group operates includes the following key elements:

- Organisational structures, delegations of authority and reporting lines;
- Group accounting and control procedures to manage the Group consolidation and reporting requirements, including:
    - Review of monthly management accounts with comparison of actual performance against budget; and consideration of the outturn for the year;
    - Monthly reconciliation of all key control accounts;
- Budgetary process and monthly monitoring of annual budget, business performance and deviations from budget; and
- Operational and strategic review processes for all aspects of the Group's business.

A number of policies and procedures are also in place as part of the Group's internal control framework, which include the Group Anti-Corruption and Money Laundering policy, the Delegation of Authority system, Travel and Entertainment and Petty Cash policies.

The Board reviews annually the effectiveness of the Group's risk management and internal control systems, based on a report from the financial controller, which is intended to give comfort regarding all material controls, including financial, operational and compliance controls.

The Audit and Risk Committee reviews annually the need to establish an internal audit function To date, it has been concluded that this remained unnecessary given the existing size and development of the Company, however this will continue to be reviewed in the light of the Acquisition and the integration of the Seven Assets.

APPENDIX 1

NOTICE TO INVESTORS

You are advised to consult legal counsel prior to making any offer, resale, pledge or other transfer of any of the Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants offered hereby.

The Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants have not been and will not be registered under the Securities Act or the securities laws of any other jurisdiction and may not be offered, sold, pledged or otherwise transferred within the United States except pursuant to an exemption from or in a transaction not subject to the registration requirements of the Securities Act and such other securities laws. Subject to certain exceptions, the offering of Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants pursuant to this Admission Document is taking place only outside the United States in offshore transactions in reliance upon Regulation S under the Securities Act. There will be no public offer of the Placing Shares or Warrants or Shares underlying the Warrants in the United States.

Each purchaser of the Placing Shares and Warrants, by its acceptance of this Admission Document, will be deemed to have acknowledged, represented and agreed as follows:

(1) The purchaser understands and acknowledges that the Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants have not been registered under the Securities Act or any other applicable securities law, the Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants contemplated in this Admission Document are being offered to it in offshore transactions not requiring registration under the U.S. Securities Act or any other securities laws in reliance on Regulation S under the U.S. Securities Act, and none of the Placing Shares and the Warrants and any Ordinary Shares that may be issued pursuant to the exercise of the Warrants may be offered, sold or otherwise transferred except in compliance with the registration requirements of the U.S. Securities Act or any other applicable securities laws, pursuant to an exemption from such laws or in a transaction not subject to such laws, and in each case, in compliance with the conditions for transfer set forth in paragraph (3) below.

(2) The purchaser is purchasing the Placing Shares and Warrants contemplated in this Admission Document in an offshore transaction in accordance with Regulation S.

(3) The purchaser is purchasing the Placing Shares and Warrants for its own account, or for one or more investor accounts for which it is acting as a fiduciary or agent, in each case for investment, and not with a view to, or for offer or sale in connection with, any distribution of the Placing Shares and Warrants in violation of the Securities Act or the securities laws of any other jurisdiction, subject to any requirement of law that the disposition of its property or the property of such investor account or accounts be, at all times, within its or their control and subject to its or their ability to resell such Placing Shares contemplated in this Admission Document pursuant to Regulation S or any exemption from registration available under the Securities Act.

(4) The purchaser acknowledges that until 40 days after the commencement of the offering, any offer or sale of the Placing Shares and Warrants within the United States by a dealer (whether or not participating in the Offering) may violate the registration requirements of the Securities Act. The purchaser acknowledges that the Company will not be required to accept for registration of transfer of any Placing Shares and Warrants acquired by them, except upon presentation of evidence satisfactory to the Company that the restrictions set forth herein have been complied with.

(5) The purchaser agrees that it will deliver to each person to whom it transfers Placing Shares and Warrants notice of any restrictions on the transfer of such securities.

(6) The purchaser acknowledges that the Company and others will rely upon the truth and accuracy of the foregoing acknowledgments, representations, warranties and agreements and agrees that if any of the acknowledgments, representations, warranties and agreements deemed to have been made by its purchase of the Placing Shares and Warrants are no longer accurate, it shall promptly provide notice. If it is acquiring any Placing Shares and Warrants as a fiduciary or agent for one or more investor accounts, it represents that it has sole investment discretion with respect to each such investor account

and that it has full power to make the foregoing acknowledgments, representations and agreements on behalf of each such investor account.

(7) The purchaser understands that no action has been taken in any jurisdiction (including the United States) by the Company or its advisers that would permit a public offering of the Placing Shares and Warrants or the possession, circulation or distribution of this Admission Document or any other material relating to the Company or the Placing Shares and Warrants in any jurisdiction where action for the purpose is required. Consequently, any transfer of the Placing Shares and Warrants will be subject to the selling restrictions set forth herein.

(8) The purchaser acknowledges that none of the Company or its advisers nor any person representing any of them, has made any representation to such purchaser with respect to the Company or the offer or sale of any of the Placing Shares or Warrants, other than the information contained in this Admission Document, which Admission Document has been delivered to such purchaser and upon which such purchaser is relying in making its investment decision with respect to the Placing Shares and Warrants.

(9) The purchaser acknowledges the advisers do not make any representation or warranty as to the accuracy or completeness of this Admission Document. The purchaser has had access to such financial and other information concerning the Company and the Placing Shares and Warrants as it has deemed necessary in connection with its decision to purchase any of the Placing Shares and Warrants, including an opportunity to ask questions of, and request information from the Company.

APPENDIX 2

NOTICE OF GENERAL MEETING

SAVANNAH PETROLEUM PLC

(Incorporated and registered in England and Wales under the Companies Act 2006 with registered number 9115262)

NOTICE IS HEREBY GIVEN THAT a general meeting (the **"GM"**) of Savannah Petroleum PLC (the **"Company"**) will be held at the Hilton London Canary Wharf, Marsh Wall, London E14 9SH at 3.00 p.m. on 8 January 2018 to consider and, if thought fit, pass the following resolutions of which resolutions 1, 2, 4 to 11 (inclusive) will be proposed as ordinary resolutions of the Company and resolutions 3 and 12 will be proposed as special resolutions of the Company:

ORDINARY RESOLUTIONS

1 THAT, conditional on the passing of resolutions 2 and 3, the combination of Seven Energy International Limited with the Company, on the terms and subject to the conditions contained in the implementation agreement (as defined in the admission document published by the Company on 22 December 2017 of which this notice forms part (the "**Admission Document**")) (the "**Transaction**") be and is hereby approved for all purposes, including, without limitation, for the purposes of Rule 14 of the AIM Rules for Companies published by the London Stock Exchange plc and that the directors of the Company (the **"Directors"**) be and are hereby authorised to take all steps necessary or, in the opinion of the Directors, desirable, to give effect to the Implementation Agreement, including without limitation, waiving, amending, varying or extending any of the conditions and terms of the Transaction;

2 THAT conditional on the passing of resolution 3:

2.1 the Directors be and are hereby generally and unconditionally authorised in accordance with Section 551 of the Companies Act 2006 (the "**Act**"), in addition to all existing authorities, to exercise all the powers of the Company to allot ordinary shares in the Company ("Ordinary Shares") or grant rights to subscribe for, or convert any security into Ordinary Shares up to an aggregate nominal value of £726,869.65, such authority to expire after the period of 12 months after the passing of this resolution, except that the Company may before such expiry make an agreement which would or might require equity securities to be allotted after such expiry (or any revocation or replacement of such authority) and the Directors may allot equity securities pursuant to such agreement as if the authority in question had not expired (or been replaced or revoked);

2.2 subject to Second Admission (as defined in the Admission Document), and in addition to the authority granted by sub-paragraph 2.1 above, the Directors be and are hereby generally and unconditionally authorised in accordance with section 551 of the Act:

2.2.1 to exercise all the powers of the Company to allot Ordinary Shares of £0.001 each in the capital of the Company ("Ordinary Shares") and to make offers or agreements to allot Ordinary Shares or grant rights to subscribe for or to convert any security into Ordinary Shares up to an aggregate nominal amount of £179,144.42;

2.2.2 to exercise all the powers of the Company to allot equity securities (within the meaning of section 560 of the Act) up to an additional aggregate nominal amount of £295,588.29 provided that this authority may only be used in connection with a rights issue in favour of holders of Ordinary Shares and other persons entitled to participate therein where the equity securities respectively attributable to the interests of all those persons at such record dates as the Directors may determine are proportionate (as nearly as may be practicable) to the respective numbers of equity securities held or deemed to be held by them or are otherwise allotted in accordance with the rights attaching to such equity securities subject to such exclusions or other arrangements as the Directors may consider necessary or expedient to deal with fractional entitlements or legal difficulties under the laws of any territory or the requirements of a regulatory body or stock exchange or by virtue of shares being represented by depositary receipts or any other matter whatsoever;

provided that the authorities in this sub-paragraph 2.2.2 shall expire at the conclusion of the next annual general meeting of the Company after the passing of this resolution or, if earlier, on the date which is 12 months from the date this resolution is passed, except that the Company may before such expiry make an offer or agreement which would or might require equity securities as the case may be to be allotted after such expiry and the Directors may allot equity securities in pursuance of any such offer or agreement as if the authority in question had not expired.

SPECIAL RESOLUTIONS

3 THAT, conditional on the passing of resolution 2:

3.1 subject to Second Admission, the Directors be and are hereby generally and unconditionally authorised pursuant to sections 570 and 573 of the Act to make allotments of equity securities (within the meaning of section 560 of the Act) for cash pursuant to the authority conferred by sub-paragraph 2.1 as if section 561 of the Act did not apply to any such allotment, such authority to expire after the period of 12 months after the passing of this resolution, save that the Company may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry date and the Directors may allot equity securities in pursuance of such offer or agreement notwithstanding that the power conferred by this resolution had expired;

3.2 subject to Second Admission, the Directors be and are hereby generally and unconditionally authorised pursuant to sections 570 and 573 of the Act to make allotments of equity securities (within the meaning of section 560 of the Act) for cash pursuant to the authority conferred by sub-paragraph 2.2 above as if section 561 of the Act did not apply to any such allotment provided that such power shall be limited to:

3.2.1 the allotment of equity securities in connection with or pursuant to any issue or offer by way of rights or other pre-emptive offer to the holders of ordinary shares of £0.001 each in the capital of the Company and other persons entitled to participate therein in proportion (as nearly as practicable) where the equity securities respectively attributable to the interest of all those persons at such record dates as the Directors may determine are proportionate (as nearly as may be practicable) to the respective numbers of equity securities held or deemed to be held by them or are otherwise allotted in accordance with the rights attaching to such equity securities, but subject to such exclusions or other arrangements as the Directors may deem necessary or expedient in relation to legal or practical issues under the laws of, or as a requirement of, any regulatory or stock exchange authority in any jurisdiction or territory or in relation to fractional entitlements; and/or

3.2.2 the allotment (otherwise pursuant to sub-paragraph 3.2.1 above) of equity securities up to an aggregate nominal value of £179,144.42 (being 20 per cent. of Further Enlarged Share Capital (as defined in the Admission Document),

such authority to expire at the conclusion of the Company's next annual general meeting or, if earlier, 12 months from the date this resolution is passed, save that the Company may before such expiry make an offer or agreement which would or might require equity securities to be allotted after such expiry date and the Directors may allot equity securities in pursuance of such offer or agreement notwithstanding that the power conferred by this resolution had expired.

ORDINARY RESOLUTIONS

4 THAT Andrew Knott be re-elected as a director of the Company.

5 THAT Mark Iannotti be re-elected as a director of the Company.

6 THAT Stephen Jenkins be re-elected as a director of the Company.

7 THAT David Jamison be re-elected as a director of the Company.

8 THAT Isatou Semega-Janneh be re-elected as a director of the Company.

9 THAT David Clarkson be re-elected as a director of the Company.

10 THAT Sir Stephen O'Brien be re-elected as a director of the Company.

11 THAT Michael Wachtel be re-elected as a director of the Company.

SPECIAL RESOLUTION

12 THAT the Company be generally and unconditionally authorised for the purpose of Section 701 of the Act to make market purchases (within the meaning of Section 693(4) of the Act) of Ordinary Shares on such terms and in such manner as the Directors may from time to time determine provided that:

12.1 the maximum number of Ordinary Shares in the Company which may be purchased is 89,572,210;

12.2 the minimum price, exclusive of any expenses, which may be paid for each Ordinary Share is £0.001, being the nominal value of Ordinary Shares in the Company;

12.3 the maximum price, exclusive of any expenses, which may be paid for each Ordinary Share is an amount equal to the higher of:

12.3.1 105 per cent. of the average market value of an Ordinary Share, as derived from the London Stock Exchange Daily Official List for the five business days prior to the day on which the purchase is made; and

12.3.2 An amount equal to the higher of the price of the last independent trade of an Ordinary Share and the highest current independent bid for an Ordinary Share unless previously revoked, renewed, extended or varied.

The authority hereby conferred shall expire on the date of the next annual general meeting of the Company but provided that the Company may, before such expiry, enter into a contract or contracts to purchase shares which will or may be executed wholly or partly after the expiry of such authority and the Company may make a purchase of shares under such contract or contracts as if the authority had not expired.

By order of the Board

Andrew Knott
Chief Executive Officer, on behalf of Savannah Petroleum plc
Registered office: 40 Bank Street, London, E14 5NR
Dated: 22 December 2017

IMPORTANT NOTES

The following notes explain your general rights as a shareholder and your right to attend and vote at this general meeting or appoint someone else on your behalf.

1. To be entitled to attend, speak and vote at the general meeting (and for the purpose of the determination by the Company of the votes you may cast), you must be registered in the Register of Members of the Company at close of trading on 6 January 2018 (or, in the event of any adjournment, close of business on the date which is 48 hours before the time of the adjourned meeting). Changes to the Register of Members after the relevant deadline shall be disregarded in determining the rights of any person to attend and vote at the meeting. There are no other procedures or requirements for Members to comply with in order to attend and vote at the general meeting.
2. It is the current intention that voting at the general meeting will be conducted by way of a poll and not by a show of hands. The Company believes that a poll is more representative of shareholders' voting intentions because shareholder votes are counted according to the number of Ordinary Shares held and all votes tendered are taken into account.
3. The doors will open at 2.00 p.m. and you may wish to arrive by 2.30 p.m. to enable you to register and take your seat in good time. If you have any special needs or require wheelchair access to the premises where the general meeting is being held, in advance of the meeting, please contact the

Company's Registrar using the contact details set out in Note 23 below. Mobile phones may not be used in the meeting hall and cameras and recording equipment are also not allowed in the meeting hall.

4. If you are a Member at the time set out in Note 1 above, you are entitled to appoint a proxy to exercise all or part of your rights to attend, speak and vote at the meeting and you should have received a Form of Proxy with this Notice. You can only appoint a proxy using the procedures set out in these notes and the notes to the Form of Proxy. If you do not have a Form of Proxy and believe that you should have one, or if you require additional forms, please contact the Company's Registrar using the contact details set out in Note 23 below. A proxy need not be a Member but must attend the meeting to represent you. If you wish your proxy to speak on your behalf at the meeting you will need to appoint your own choice of proxy (not the Chairman) and give your instructions directly to them.

5. You may appoint more than one proxy provided that each proxy is appointed to exercise the rights attached to a different Ordinary Shares. You may not appoint more than one proxy to exercise the rights attached to any one share. To appoint more than one proxy, please contact the Company's Registrar using the contact details set out in Note 23 below.

6. In the case of joint holders, where more than one of the joint holders purports to appoint a proxy, only the appointment submitted by the most senior holder will be accepted. Seniority is determined by the order in which the names of the joint holders appear in the Company's Register of Members in respect of the joint holding (the first named being the most senior).

7. Any person to whom this Notice is sent who is a person nominated under Section 146 of the Companies Act 2006 to enjoy information rights (a **"Nominated Person"**) may, under an agreement between him/her and the Member by whom he/she was nominated, have a right to be appointed (or to have someone else appointed) as a proxy for the general meeting. If a Nominated Person has no such proxy appointment right or does not wish to exercise it, he/she may, under any such agreement, have a right to give instructions to the Member as to the exercise of voting rights.

8. The statement of the rights of shareholders in relation to the appointment of proxies in Notes 4, 5, 6 and 11 do not apply to Nominated Persons. The rights described in these paragraphs can only be exercised by Members of the Company.

9. The notes to the Form of Proxy explain how to direct your proxy on how to vote on each resolution or withhold their vote. A vote withheld is not a vote in law, which means that the vote will not be counted in the calculation of votes for or against the resolution. If no voting indication is given, your proxy will vote or abstain from voting at his or her discretion. Your proxy will vote (or abstain from voting) as he or she thinks fit in relation to any other matter which is put before the general meeting.

10. The return of a completed form of proxy, other such instrument or any CREST Proxy Instruction (as described in Note 13 below) will not prevent a shareholder attending the general meeting and voting in person if he/she wishes to do so.

11. To be valid, any Form of Proxy or other instrument appointing a proxy must be received by post or (during normal business hours only) by hand at the Company's Registrar, at the address shown on the Form of Proxy or, in the case of shares held through CREST, via the CREST system (see Note 12 below). Alternatively, a duly completed Form of Proxy may be scanned and sent by email to externalproxyqueries@computershare.co.uk. In each case, for proxy appointments to be valid, they must be received no later than 3.00 p.m. on 6 January 2018. Electronic communication facilities are open to all shareholders and those who use them will not be disadvantaged. If you return more than one proxy appointment, either by paper or electronic communication, the proxy appointment received last by the Company's Registrar before the latest time for the receipt of proxies will take precedence.

12. 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 of the general meeting) by using the procedures described in the CREST Manual (available from https://www.euroclear.com). CREST Personal Members or other CREST sponsored members, and those CREST members who have appointed a 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.

13. In order for a proxy appointment made by means of CREST to be valid, the appropriate CREST message (a "CREST Proxy Instruction") must be properly authenticated in accordance with Euroclear UK & Ireland Limited's specifications and must contain the information required for such instructions, as described in the CREST Manual. The message must be transmitted so as to be received by the

issuers' agent (ID 3RA50) by 3.00 p.m. on 6 January 2018. For this purpose, the time of receipt will be taken to be the time (as determined by the timestamp applied to the message by the CREST application host) from which the issuers' 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.

14. CREST members and, where applicable, their CREST sponsors, or voting service providers should note that Euroclear UK & Ireland Limited does not make available special procedures in CREST for any particular message. 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 a 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 system providers 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.

15. In the case of a Member which is a company, the Form of Proxy must be executed under its common seal or signed on its behalf by an officer of the company or an attorney of the company. Any power of attorney or any other authority under which the Form of Proxy is signed (or a duly certified copy of such power or authority) must be included with the Form of Proxy.

16. Any corporation which is a Member may, by resolution of its directors or other governing body appoint one or more corporate representatives who may exercise on its behalf all of its powers as a member provided that no more than one corporate representative exercises powers in relation to the same shares. Corporate representatives should bring with them either an original or certified copy of the appropriate board resolution or an original letter confirming the appointment, provided it is on the corporation's letterhead and is signed by an authorized signatory and accompanied by evidence of the signatory's authority.

17. Under Section 527 of the Act, shareholders meeting the threshold requirements set out in that section have the right to require the Company to publish on a website a statement setting out any matter relating to: (i) the audit of the Company's accounts (including the Auditor's Report and the conduct of the audit) that are to be laid before the general meeting; or (ii) any circumstances connected with an auditor of the Company ceasing to hold office since the previous meeting at which annual accounts and reports were laid in accordance with Section 437 of the Act. The Company may not require the shareholders requesting any such website publication to pay its expenses in complying with Sections 527 or 528 of the Act. Where the Company is required to place a statement on a website under Section 527 of the Act, it must forward the statement to the Company's auditor not later than the time when it makes the statement available on the website. The business which may be dealt with at the general meeting includes any statement that the Company has been required under Section 527 of the Act to publish on a website.

18. Any shareholder attending the 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 for 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.

19. Copies of the service contracts of the Executive Director and the letters of appointment of the Chairman and Non-Executive Directors are available for inspection during normal business hours at the registered office of the Company and may also be inspected at the general meeting venue for 15 minutes prior to and during the meeting.

20. As at 21 December 2017 (being the last practicable business day prior to the publication of this Notice), the Company's ordinary issued share capital consists of 274,621,447 Ordinary Shares, carrying one vote each. No shares were held in treasury. Therefore, the total voting rights in the Company as at 21 December 2017 were 274,621,447.

21. Information regarding the Company's general meeting can be found at www.savannah-petroleum.com

22. You may not use any electronic address provided in either this Notice or any related documents (including the Form of Proxy) to communicate with the Company for any purposes other than those expressly stated.

23. Members who have general queries about the meeting should call the Company's Registrar, Computershare Investor Services plc on 0370 707 1133 (or, if calling from outside the UK, on +44 (0) 370 707 1133. Calls from within the UK are charged at standard local call rates, lines are open 8.30 a.m. – 5.30 p.m., Monday to Friday. Calls from outside the UK will be charged at the applicable international rate. Different charges may apply to calls made from mobile telephones and calls may be recorded and randomly monitored for security and training purposes. Please note that Computershare Investor Services plc cannot provide investment advice, nor advise you how to cast your vote on the resolutions.

DEFINITIONS

The following definitions apply throughout this document, unless otherwise stated or the context requires otherwise:

10.50 per cent. Notes	SEFL's 10.50 per cent. senior secured notes due 2021;
Accugas	Accugas Holdco and its subsidiaries from time to time;
Accugas Documents	the documents required to be entered into to effect the Accugas Transaction;
Accugas Holdco	the new holding company to be incorporated for the purpose of holding the entire issued share capital in Accugas Midco;
Accugas IV Facility Agreement	the facility agreement dated 23 June 2015 (as amended on 28 November 2016) between, *inter alia*, Accugas Limited (as sole borrower) and FBN Capital Limited (as facility agent);
Accugas Limited	Accugas Limited, a company incorporated under the laws of Nigeria with registered number 881197, whose registered office is at 35 Kofo Abayomi Street, Victoria Island, Lagos;
Accugas Midco	the new holding company to be incorporated for the purpose of holding the entire issued share capital in Exoro;
Accugas Midstream Business	the business currently operated by Accugas Limited, which is expected to become a subsidiary of Accugas Holdco, and utilising its 200 MMscfpd gas processing facility and circa 260 km gas pipeline network and associated gas processing infrastructure;
Accugas Topco	a new entity to be formed by the Investors to facilitate their investment in Accugas;
Accugas Transaction	the acquisition by Savannah of a 20 per cent. carried interest in the Accugas Midstream Business;
Accugas Waiver	an agreement between, *inter alia*, the Company, SEIL, Accugas Limited and the lenders under the Accugas IV Facility Agreement in respect of existing defaults and defaults which will arise as a result of the Transaction in connection with the Accugas IV Facility Agreement and the related common terms agreement dated 23 June 2015 (as amended on 28 November 2016 and as further amended and restated on 29 December 2016) between, *inter alia*, Accugas Limited, SEFL and SEIL;
Acquisition	the proposed acquisition by Savannah of the Seven Assets, further detail on which is disclosed in Part 2 of this document;
Act or **Companies Act**	the UK Companies Act 2006, as amended from time to time;
Agadem Rift Basin or **ARB**	the Agadem basin in South East Niger located within the Central African Rift System;
AGIP	Nigerian Agip Oil Company Limited;
AIIM	African Infrastructure Investment Fund 3;
AIM	the AIM market of the London Stock Exchange;

AIM Rules for Companies or **AIM Rules**	the London Stock Exchange's rules and guidance notes contained in its "AIM Rules for Companies" publication relating to companies whose securities are traded on AIM, as amended from time to time;
AIM Rules for Nominated Advisers	the London Stock Exchange's rules contained in its "AIM Rules for Nominated Advisers" publication relating to the nominated advisers of companies whose securities are traded on AIM, as amended from time to time;
Articles	the articles of association of the Company in force from restoration of the Company's share capital to trading on AIM on 22 December 2017;
ASMA Capital	ASMA Capital Partners B.S.C. (c), in its capacity as the fund manager of IDB Infrastructure Fund II B.S.C. (c);
Barclays	Barclays Bank PLC of 5 The North Colonnade, Canary Wharf, London E14 4BB, which is acting as Global Co-ordinator and Joint Bookrunner in connection with the Placing;
Board	the board of directors of the Company from time to time;
BVI Commercial Court	the Commercial Court in the British Virgin Islands;
Capital Invested	the gross cost of both oil and gas assets (excluding decommissioning assets) and property, plant and equipment incurred by the Seven Group since inception, excluding values for the SAA and including just 20 per cent. of Accugas Limited;
Capital Restructuring	the restructuring of Seven Energy's existing indebtedness as more fully described in Part 2 of this document;
Central African Rift System	the rift system composed of two coeval Cretaceous rift sub-systems in Central Africa;
certificated or **in certificated form**	an Ordinary Share which is not in uncertificated form (that is, not in CREST);
CGG	CGG Services (UK) Limited, the author of the Niger Competent Person's Report;
CNPC	the China National Petroleum Corporation;
CNPC PSC	the production sharing contract into which CNPC entered with the Government of Niger in 2008 in respect of the R1/R2 PSC Area and R3/R4 PSC Area;
Company or **Savannah**	Savannah Petroleum plc, a company incorporated in England and Wales with registered number 9115262, whose registered office is at 40 Bank Street, London, E14 5NR;
Completion	the completion of the Acquisition, Capital Restructuring and the Accugas Transaction pursuant to the Implementation Agreement and the Accugas Documents and following receipt of all required consents, including Ministerial Consent and NSEC Consent;
Compliance Laws	the UK Bribery Act 2010 and all other relevant and applicable anti-corruption, anti-bribery, anti-money laundering, compliance laws and regulations, and other laws governing the conduct of business

	(including with Nigerian and Nigerien government entities), including local laws, that apply to the Enlarged Group;
Consideration Shares	the 312,013,810 new Ordinary Shares proposed to be issued to the holders of the Senior Secured Notes, the holders of the Second Bilateral Facility and in consideration for the Company's acquisition of a 62.5 per cent. equity interest in Universal as part of the Acquisition and Capital Restructuring;
Conversion Price	the Placing Price;
Corporate Governance Code	the UK Corporate Governance Code published by the Financial Reporting Council in April 2016 (as amended);
CREST	the computerised settlement system (as defined in the CREST Regulations) operated by Euroclear which facilitates the transfer of title to shares in uncertificated form;
CREST Regulations	the Uncertificated Securities Regulations 2001 (SI 2001/3755) including any enactment or subordinate legislation which amends or supersedes those regulations and any applicable rules made under those regulations or any such enactment or subordinate legislation for the time being in force;
Directive	the Directive on Takeover Bids (2004/25/EC);
Directors	those persons who have been appointed as executive or non-executive directors of the Company, as applicable, whose names are set out on page 8 of this document;
DPR	the Department of Petroleum Resources, a department of the MPR;
DSA Facility Agreement	the facility agreement dated 29 December 2016 between, *inter alia*, Accugas Limited (as borrower) and FBN Capital Limited (as facility agent);
EHGC	East Horizon Gas Company Limited, a company incorporated under the laws of the Federal Republic of Nigeria with registered number 686051, whose registered office is at 35 Kofo Abayomi Street, Victoria Island, Lagos, Nigeria;
Eight Holdco	a new entity to be incorporated by Savannah to facilitate the acquisition of the Seven Assets;
Ekid Agreements	(i) the shareholders agreement between Septa Oil Trading Company Limited, Frontier and Ekid Gas Processing Company Limited dated 2 June 2010; (ii) the gas processing agreement between Ekid Gas Processing Company Limited, Frontier and GOGE (NIG) Limited (now known as SUGL) dated 2 June 2010; (iii) the hire purchase agreement between Accugas Limited and Ekid Gas Processing Company Limited dated 2 June 2010 (as amended from time to time); and (iv) the operation and maintenance agreement between Ekid Gas Processing Company Limited and Frontier dated 2 June 2010;
Elf	Elf Petroleum Nigeria Limited;
English High Court	the High Court of England and Wales;
Enlarged Group	the Company and its subsidiaries immediately following Completion;

Euro or **€**	the official currency of the European Union;
Euroclear	Euroclear UK & Ireland Limited, a company incorporated in England & Wales with registered number 2878738, being the operator of CREST;
Exchange Offer	the exchange offer that may be made by the Company to effect the SSN element of the Capital Restructuring, as more fully described in paragraph 5 of Part 2 of this document;
Existing Group	the Company and its subsidiaries prior to Completion;
Existing Ordinary Shares	the 274,621,447 Ordinary Shares in issue prior to First Admission as at the date of this document;
Exoro	Exoro Holding B.V., a company incorporated in the Netherlands with registered number 2730262, whose registered office is at 6 Chesterfield Gardens, London, W1J 5BO and which owns the entire issued share capital in Accugas Limited;
ExxonMobil	Exxon Mobil Corporation;
FCA	the Financial Conduct Authority (formerly the Financial Services Authority) of the United Kingdom;
First Admission	admission of the Initial Enlarged Share Capital to trading on AIM and such admission becoming effective in accordance with the AIM Rules for Companies;
First Bilateral Facility	the facility agreement dated 23 June 2015 between, *inter alia*, SEFL and Seven Energy Ltd. (as borrowers) and the Agent (as defined therein);
First Tranche Placing Shares	27,462,000 new Ordinary Shares to be issued by the Company and subscribed for pursuant to the Placing;
Form of Proxy	the form of proxy for use in connection with the General Meeting, which is enclosed with this document;
Frontier	Frontier Oil Limited, a company incorporated under the laws of the Federal Republic of Nigeria with registered number 41178, whose registered office is at 9C Joseph Adu Street, Oniru Estate, Victoria Island, Lagos, Nigeria;
Frontier Agreements	(i) the fifth side letter relating to the Uquo JOA between Frontier and SUGL; (ii) the joint operating agreement relating to the Uquo CPF between Frontier and Accugas Limited; (iii) the crude oil processing agreement between Frontier, SUGL and Accugas Limited; (iv) the amendment to the Uquo CPF sub-lease agreement between Frontier and Accugas Limited; (v) the consolidated upstream gas purchasing agreement between Accugas Limited, Frontier and SUGL; (vi) termination agreements in relation to each of the Ekid Agreements; and (vii) a settlement agreement in relation to any outstanding claims of Frontier against the Seven Group;
FSMA	the Financial Services and Markets Act 2000 of the UK (as amended), including any regulations made pursuant thereto;
FUN Group	Frontier Oil Nigeria Limited, Universal and Network Exploration & Production Nigeria Limited;

FUN Manifold	the facilities for storing, handling and exporting crude oil from the Uquo, Stubb Creek and Qua Ibo fields to the QIT;
Further Enlarged Share Capital	the 895,722,095 Ordinary Shares in issue on Second Admission, comprising the Initial Enlarged Share Capital, the Second Tranche Placing Shares, the Consideration Shares and any Ordinary Shares used pursuant to the exercise of any of the Warrants;
General Meeting	the general meeting of the Company to be held at the Hilton London Canary Wharf, Marsh Wall, London E14 9SH on 8 January 2018 at 3.00 p.m., formal notice of which is set out in this document;
Group	the Company and its subsidiaries from time to time;
Hannam & Partners	Hannam & Partners (Advisory) LLP of 2 Park Street, London, W1K 2HX, who is acting as the Company's Joint Corporate Broker and Financial Adviser;
IFRS	International Financial Reporting Standards, as adopted by the European Union;
Implementation Agreement	the agreement to be entered into between the Company, Seven and certain creditors of Seven to document the legal terms and steps on which the Acquisition and Capital Restructuring will take place, as more fully described in Part 2 of this document;
Initial Enlarged Share Capital	the 302,083,447 Ordinary Shares in issue on First Admission, comprising the Existing Ordinary Shares and the First Tranche Placing Shares;
Investors	AIIM, together with one or more potential co-investors;
ISIN	International Securities Identification Number;
Last Practicable Date	21 December 2017, being the last practicable day prior to the publication of this document for the inclusion of certain information in this document;
Lock-up Agreement	the agreement entered into between the Company, Seven and certain of the Seven Group's key creditors on 14 November 2017 to support and facilitate, subject to certain conditions, the Capital Restructuring and the Acquisition, as more fully described in Part 2 of this document;
Lock-up Amendment Agreement	the amendment to the Lock-Up Agreement between, amongst others, Seven Energy and the Company dated on or around 20 December 2017;
London Stock Exchange	London Stock Exchange plc;
Long-Term Incentive Plan	the Company's initial long-term incentive plan, which was established on 28 November 2014, further details on which are contained in paragraph 4.2 of Part 13 of this document and in the Company's announcement on 1 December 2014;
LR	LR Senergy Limited, the author of the Nigeria CPR;
Marginal Field Guidelines	the Guidelines For Farmout And Operation of Marginal Fields 2001 published by the DPR in Nigeria;

Market Abuse Regulations	Market Abuse Regulation (Regulation 596/2014);
MEND	the Movement for the Emancipation of the Niger Delta;
MOU	memorandum of understanding;
MPN	Mobil Producing Nigeria Unlimited, a subsidiary of ExxonMobil;
MPR	the Federal Ministry of Petroleum Resources in Nigeria;
Ministerial Consent	the consent of the Minister of Petroleum Resources to the Acquisition in accordance with Petroleum Act and the Oil Pipelines Act;
Mirabaud	Mirabaud Securities Limited of 10 Bressenden Place, London, SW1E 5DH, which is acting as Joint Bookrunner and Joint Broker in connection with the Placing;
NERC	the Nigerian Electricity Regulatory Commission;
Niger CPR or **Niger Competent Person's Report**	CGG's competent person's report on the Group's Nigerien assets, as set out in Part 12 of this document;
Nigeria CPR or **Nigeria Competent Person's Report**	LR's competent person's report on the Group's Nigerian assets, as set out in Part 11 of this document;
NGN	Nigerian Naira, the functional currency of Nigeria;
NNDC	New Nigeria Development Company Ltd., a conglomerate owned by the 19 Northern States of Nigeria, with a place of business at Ahmed Talib House, 18/19 Ahmadu Bellow Way, Kaduna, Kaduna State, Nigeria;
NNPC	Nigerian National Petroleum Corporation, with its corporate headquarters at NNPC Towers, Central Business District, Herbert Macaulay Way, P.M.B. 190, Garki, Abuja, Nigeria;
NPDC	Nigerian Petroleum Development Company, with its head office at 62/64 Sapele Road, Benin City, Edo State, Nigeria;
Notice of General Meeting	formal notice convening the General Meeting, which is set out at the end of this document;
NSEC	Nigerian Securities and Exchange Commission;
NSEC Consent	NSEC's consent to the Company's acquisition of 62.5 per cent. of Universal;
Official List	the Official List maintained by the UK Listing Authority pursuant to Part VII of the FSMA;
Ordinary Shares	the ordinary shares of par value £0.001 each in the capital of the Company;
Panel	the UK Panel on Takeovers and Mergers;
PIB	Petroleum Industry Bill of Nigeria;
Placee	an investor to whom Placing Shares are issued pursuant to the Placing;

Placing	the placing by the Company of the Placing Shares with institutional and other investors at the Placing Price pursuant to the Placing Agreement;
Placing Agreement	the conditional agreement dated 22 December 2017 between (1) the Company, (2) the Directors, (3) Strand Hanson, (4) Barclays, (5) Mirabaud and (6) Shore Capital, further details of which are set out in paragraph 9.2 of Part 14 of this document;
Placing Price	35 pence (US$0.47 equivalent) per Placing Share;
Placing Shares	the First Tranche Placing Shares and the Second Tranche Placing Shares
Pounds Sterling or **£**	pounds sterling, the lawful currency of the UK from time to time;
Promissory Note	the promissory note dated 12 December 2014 originally issued by SEIL to GEC Petroleum Development Company Limited ("**GEC**"), as assigned by GEC to FBN Capital Limited pursuant to a deed of assignment dated 12 December 2014 between GEC, FBN Capital Limited and SEIL, as novated from SEIL to SEFL pursuant to a novation and variation agreement dated on 21 July 2015 between SEIL, SEFL and FBN Capital Limited, and as amended pursuant to letters dated 6 June 2016 and 18 January 2017 in each case between SEFL and FBN Capital Limited;
Prospectus Directive	Directive 2003/71/EC and includes any relevant 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;
QCA Code	The Quoted Companies Alliance Corporate Governance Code for Small and Mid-Size Quoted Companies;
QIT	the Qua Iboe oil export terminal owned and operated by MPN, a subsidiary of ExxonMobil;
R1/R2 PSC	the production sharing contract between Savannah Niger and the Government of Niger dated 3 July 2014 and its amendment no. 1 dated 2 November 2015 and amendment no. 2 dated 26 October 2016 in respect of the R1/R2 PSC Area;
R1/R2 PSC Area	the R1/R2 areas in south-eastern Niger that are the subject of the R1/R2 PSC;
R1/R2 Signature Bonus	the payments of $34 million and $2,720,000 made by the Group to the Government of Niger represented by the Ministry of Energy and Petroleum and their advisers on or around 4 August 2014 pursuant to the R1/R2 PSC;
R3/R4 PSC	the production sharing contract between Savannah Niger and the Government of Niger dated 30 July 2015 and its amendment no.1 dated 2 November 2015 and amendment no. 2 dated 26 October 2016 in respect of the R3/R4 PSC Area;
R3/R4 PSC Area	the R3/R4 areas in south-eastern Niger that are the subject of the R3/R4 PSC;

R3/R4 Signature Bonus	the payments of $28 million and $2,240,000 made by the Group to the Government of Niger represented by the Ministry of Energy and Petroleum and their advisers on or around 31 July 2015 pursuant to the R3/R4 PSC;
Re-Admission	re-admission of the Further Enlarged Share Capital, on Completion, to trading on AIM and such admission becoming effective in accordance with the AIM Rules for companies;
Registrar	Computershare Investor Services plc;
Regulation S	Regulation S promulgated under the Securities Act;
Resolutions	the resolutions to be proposed at the General Meeting, as set out in the Notice of General Meeting;
SAA	the strategic alliance agreement between NPDC and SEPL dated 15 September 2010;
Savannah Niger	Savannah Petroleum Niger R1/R2 S.A. a société anonyme unipersonelle incorporated under the laws of Niger with registered number RCCM: NI-NIA-2014-B 1940, whose registered office is at 124 Rue des Ambassades, BP11272, Niamey, Niger;
Savannah PSCs	the R1/R2 PSC and the R3/R4 PSC;
Scheme Approvals	the sanctioning by the English High Court and the BVI Commercial Court of the schemes of arrangement which may be undertaken to effect certain aspects of the Capital Restructuring;
Scheme of Arrangement	the scheme of arrangement that may be undertaken to effect the SSN element of the Capital Restructuring, as more fully described in paragraph 6 of Part 2 of this document;
SEC	US Securities and Exchange Commission;
Second Admission	admission of the Further Enlarged Share Capital to trading on AIM and such admission becoming effective in accordance with the AIM Rules for Companies;
Second Bilateral Facility	the facility agreement dated 26 June 2015 between, *inter alia*, SEFL and Seven Energy Ltd. (as borrowers) and The Law Debenture Trust Corporation P.L.C. (as security agent);
Second Tranche Placing Shares	239,000,000 new Ordinary Shares to be issued by the Company and subscribed for pursuant to the Placing, conditional on the passing of the Resolutions and the completion of either the Exchange Offer or the Scheme of Arrangement;
Securities Act	US Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder;
Senior Managers	Manish Maheshwari, Jessica Hostage, Yacine Wafy, Antoine Richard, Phil Magor, Chris Thomas and Ian Brown-Peterside;
SEFL	Seven Energy Finance Limited, a company incorporated in the British Virgin Islands with registered number 1811786, whose registered office is at 9 Columbus Centre, Pelican Drive P.O. Box 805, Road Town Tortola VG1110;

SEPL	Seven Exploration & Production Limited, previously known as Septa Energy Nigeria Limited, a company incorporated in Nigeria with registered number 674420, whose registered office is at 35 Kofo Abayomi Street, Victoria Island, Lagos, Nigeria;
Seven or **Seven Energy** or **SEIL**	Seven Energy International Limited, a company incorporated in Mauritius with registered number 65304 C2/GBL, whose registered office is at c/o International Management (Mauritius) Ltd, Les Cascades Building, Edith Cavel Street, Port-Louis, Mauritius;
Seven Assets	Seven's interests in the Uquo Field and the Stubb Creek Field, and a 20 per cent. interest in the Accugas Midstream Business;
Seven Energy Court Meetings	the creditor meetings to be held pursuant to the schemes of arrangement which may be undertaken to effect the SSN element of the Capital Restructuring;
Seven Energy Court Resolutions	the resolutions to be voted on by the holders of the SSNs at the Seven Energy Court Meetings;
Seven Energy Creditor Group	the holders of the outstanding debt in Seven Energy, as more particularly described in Part 2;
Seven Group	Seven and its subsidiary entities;
Shareholders	holders of Ordinary Shares, from time to time;
Share Options	options to subscribe for new Ordinary Shares;
Shell	Royal Dutch Shell;
Shore Capital	Shore Capital Stockbrokers Limited of Bond Street House, 14 Clifford Street, London, W1S 4JU, which is acting as Lead Manager in connection with the Placing;
Significant Shareholder	a Shareholder holding three per cent. or more of the Ordinary Shares in issue from time to time;
Sinopec	Sinopec International Petroleum Exploration and Production Company Nigeria Limited;
SPDC	Shell Petroleum Development Company of Nigeria Limited;
SSNs	10.25 per cent. senior secured notes due 2021 issued by SEFL;
Strand Hanson	Strand Hanson Limited of 26 Mount Row, London, W1K 3SQ, the Company's financial and nominated adviser;
Stubb Creek EPF	the early production facilities located at the Stubb Creek Field;
Stubb Creek Field	the Stubb Creek marginal field located in the OML 14 block onshore Nigeria;
Stubb Creek JV	the joint venture between Universal and Sinopec in connection with the Stubb Creek Field;
SUGL	Seven Uquo Gas Limited (previously known as GOGE (Nig) Limited), a company incorporated under the laws of the Federal Republic of Nigeria, with registered number 659675, whose registered office is at 35 Kofo Abayomi Street, Victoria Island, Lagos, Nigeria;

Supplementary Plan	the Company's supplementary long-term incentive plan, further details on which are contained in paragraph 4.3 of Part 13 of this document and in the Company's announcement on 30 June 2015;
Takeover Code	the UK City Code on Takeovers and Mergers (as amended from time to time);
Transaction	the Placing, the Acquisition, the Accugas Transaction and the Capital Restructuring;
UK or **United Kingdom**	the United Kingdom of Great Britain and Northern Ireland;
UKLA or **UK Listing Authority**	the FCA, acting in its capacity as the competent authority for the purposes of Part VI of the FSMA;
uncertificated or **in 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, by virtue of the CREST Regulations, may be transferred by means of CREST;
Unicem	United Cement Company of Nigeria Limited;
United States 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;
Universal	Universal Energy Resources Limited, a company incorporated under the laws of the Federal Republic of Nigeria with registered number 429120, whose registered office is 25 Idoro Road, Uyo, Akwa Ibom State, Nigeria;
Uquo CPF	the 200 MMscfd gas processing facilities, owned by Accugas Limited and located at the Uquo Field;
Uquo Field	the Uquo marginal field located in the OML 13 block onshore Nigeria;
Uquo Field TSA	the technical services agreement between Frontier and SUGL dated 9 January 2007;
Uquo JOA	the joint operating agreement between Frontier and SUGL dated 9 January 2007, more particularly described in paragraph 3.2 of Part 14 of this document;
Uquo JV	the joint venture between SUGL and Frontier in connection with the Uquo Field;
US Dollar, US$** or **$	the legal currency of the United States from time to time;
WCF Agreement	the working capital facility agreement dated 2 October 2015 between, *inter alia*, SEFL (as one of the working capital facility borrowers) and FBN Capital Limited (as facility agent);
World Bank Partial Risk Guarantee	the guarantee of the payment obligations under the downstream GSA between Accugas and Calabar Generation Company Limited, provided by the World Bank's International Development Association;
VAT	valued added tax; and
XOF	West African CFA Franc, the functional currency of Niger.

A glossary of technical terms and expressions is set out on pages 497 to 500 of this document.

GLOSSARY

The following table provides an explanation of certain technical terms and abbreviations used in this document. The terms and their assigned meanings may not correspond to standard industry meanings or sage of these terms.

2D seismic	geophysical data that depicts the subsurface strata in two dimensions;
2P Reserves	proven and probable reserves;
3D seismic	geophysical data that depicts the subsurface strata in three dimensions. 3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic
°API	a standard measure of oil density, as defined by the American Petroleum Institute;
appraisal well	a well drilled as part of an appraisal drilling programme which is carried out to determine the physical extent, reserves and likely production rate of a field;
barrels or **bbl**	a unit of volume measurement used for petroleum and its products (for a typical crude oil 7.3 barrels = 1 tonne: 6.29 barrels = 1 cubic meter);
Bcf	billion standard cubic feet; 1 bscf is approximately equal to 166,667 boe or 23,618 tonnes of oil equivalent;
Best Estimate	the middle value in a range of estimates considered to be the most likely. If based on a statistical distribution, can be the mean, median or mode depending on usage;
Block	an area defined for exploration licensing;
blow-out	an uncontrolled flow of gas, oil, or other well fluids into the atmosphere or into an underground formation;
Bnbbls	billions of barrels of oil;
Boe	barrels of oil equivalent. One barrel of oil is approximately the energy equivalent of 6,000 cf of natural gas;
Bopd	barrels of oil per day;
carbonates	a sedimentary rock composed primarily of calcium carbonate (limestone) or calcium magnesium carbonate (dolomite);
Chance of Success or **CoS**	the estimated chance, or probability, of making an oil and gas discovery in an exploration well;
Clastics	sediments formed by the breakdown of large rock masses by climatological processes, physical or chemical;
Condensate	light hydrocarbon compounds that condense into liquid at surface temperatures and pressures. They are generally produced with natural gas and are a mixture of pentane and higher hydrocarbons;
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;

Cretaceous	geological strata formed during the period 140 million to 65 million years before the present;
crude oil	hydrocarbons that at atmospheric temperature and pressure are in a liquid state, including crude mineral oil, asphalt and ozokerites, and liquid hydrocarbons that are obtained by the separation treatment, processing or extraction;
DCQ	daily contract quantity;
debottlenecked	process of identifying specific areas and/or equipment in oil and gas facilities that limit the flow of product and optimising them so that overall capacity in the plant can be increased;
Deltaic	sediments deposited in an ancient (or present day) river delta;
Dip	the inclination of a horizontal structure from the horizontal;
discovery well	an exploration well which has encountered hydrocarbons for the first time in a structure;
drilling rig	the derrick or most drawworks, and attendant surface equipment of a drilling or workover unit;
EBITDAX	earnings before interest and tax, depreciation, amortisation and capex;
E&P	exploration and production;
Eocene horizon	stratigraphic section of Eocene age (approx. 55 – 34 mybp);
Exploration Risk Factor	the estimated probability of discovering hydrocarbons within an exploration prospect. Also known as Chance of Success, or CoS.;
exploration well	a well drilled to find hydrocarbons in an unproved area or to extend significantly a known oil or natural gas reservoir;
fault or **faulting**	a displacement (vertical, inclined or lateral) below the earth's surface that acts to offset rock layers relative to one another. Faulting can create traps for hydrocarbons;
Field	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition;
Formation	a layer or unit of rock. A productive formation in the context of reservoir rock;
FTG Survey	a full tensor gravity gradiometry survey;
full tensor gravity	a form of gravimetric survey;
geophysical	measurement of the earth's physical properties to explore and delineate hydrocarbons by means of electrical, seismic, gravity and magnetic methods;
gross resources	the total estimated petroleum that is potentially recoverable from a field or prospect;
GSA	gas sales agreement;

hydrocarbon	a compound containing only the elements hydrogen and carbon. May exist as a solid, a liquid or a gas. The term is mainly used in a catch-all sense for oil, gas and condensate;
Investment grade	a rating that indicates that a municipal or corporate bond has a relatively low risk of default;
Kbpod	thousands of barrels of oil per day;
Km	kilometer;
km^2	square kilometers;
Lacustrine	sediments deposited in an ancient (or present day) freshwater lake;
Lead	a conceptual exploration idea usually based on minimal data but with sufficient support from geological analogues and the like to encourage further data acquisition and/or study on the basis that hydrocarbon accumulations of unknown size may be found in the future;
licence	an exclusive right to search for or to develop and produce hydrocarbons within a specific area and/or a pipeline licence, as the context requires. Usually granted by the State authorities and may be time limited;
Lower Cretaceous	stratigraphic section of Early Cretaceous age (approx. 145 – 100 mybp);
M	metres;
Mcf	thousand cubic feet of natural gas;
Mmbbls	millions of barrels of oil;
Mmboe	millions of barrels of oil equivalent;
MMBtu	millions of British Thermal Units;
MMscfpd	millions of standard cubic feet per day;
Mscf	thousand standard cubic feet (equivalent to 1.037 MMBtu);
Mybp	millions of years before present;
natural gas	hydrocarbon that at a standard temperature of sixty degrees Fahrenheit (60ºF) and a standard pressure of one atmosphere are in a gaseous state, including wet mineral gas and dry mineral gas, casing head gas, residual gas remaining after separation treatment, processing, or extraction of liquid hydrocarbons;
oil equivalent	international standard for comparing the thermal energy of different fuels;
Operator	the entity that has legal authority to drill wells and undertake production of hydrocarbons found. The operator is often part of a consortium and acts on behalf of this consortium;
Paleocene	period of geological time, approximately 65 to 55 mybp;
Petroleum	a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products;
permeability	a measure of the ability of a material (such as rocks) to transmit fluids;

pinch-out	to taper to a zero edge;
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;
Porosity	the percentage of void in a porous rock compared to the solid formation;
Prospect	a project associated with a potential accumulation of oil or natural gas that is sufficiently well defined to represent a viable drilling target;
prospective resources	those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects;
Reserves	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;
Reservoir	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system;
resources	deposits of naturally occurring hydrocarbons which, if recoverable, include those volumes of hydrocarbons either yet to be found (prospective) or if found the development of which depends upon a number of factors (technical, legal and/or commercial) being resolved (contingent);
Scf	standard cubic feet;
Seal	a relatively impermeable rock, commonly shale, anhydrite or salt, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system;
seismic survey	a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two or three-dimensional form;
stratigraphic	a mode of trapping hydrocarbons which is not dependent on structural entrapment;
Tscf	trillion standard cubic feet;
Tertiary	geological strata formed during the period from 65 to 1.8 mybp;
TVDSS	true vertical depth sub-sea;
Upper Cretaceous	period of geological time, approximately 100 to 65 mybp;
up-dip	up the plane of the dip;
USGS	US Geological Survey;
Volcanics	rocks derived from an ancient (or present day) volcano; and
Yet-to-find or YTF	estimated volumes of hydrocarbons which are as yet undiscovered.

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