SAVANNAH ENERGY

SAVANNAH ENERGY PLC

SUPPLEMENTAL ADMISSION DOCUMENT

APRIL 2020

STRAND HANSON

Financial & Nominated Adviser
Strand Hanson Limited

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 entire issued share capital of the Company (the "**Existing Share Capital**") on AIM ("**Re-Admission**").

Savannah Energy PLC (the "**Company**") and its directors (together, the "**Directors**"), whose names appear on page 5 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 has been made for Re-Admission of the Existing Share Capital. The Existing 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 Existing Share Capital to be admitted to trading on any such 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 Existing 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 ENERGY PLC

(formerly Savannah Petroleum PLC)

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

COMPLETION OF THE SEVEN ENERGY TRANSACTION AND RE-ADMISSION OF THE EXISTING SHARE CAPITAL TO TRADING ON AIM

Financial & Nominated Adviser

Strand Hanson Limited

Strand Hanson Limited ("**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 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 Re-Admission.

Mirabaud Securities Limited ("**Mirabaud**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Joint Broker to the Company in connection with 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 Re-Admission.

Numis Securities Limited ("**Numis**"), which is authorised and regulated in the United Kingdom by the Financial Conduct Authority, is acting as Joint Broker to the Company in connection with Re-Admission. Numis 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 Re-Admission.

None of Strand Hanson, Mirabaud or Numis have authorised the contents of this document and no representation or warranty, express or implied, is made by any of Strand Hanson, Mirabaud or Numis 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, Mirabaud or Numis 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 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 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 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 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 the United States, 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, Mirabaud or Numis 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 additional 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 Re-Admission 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. 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 Computershare Investor Services plc at the Pavillions, Bridgwater Road, Bristol, BS13 8AE and from the Company's website: http://www.savannah-energy.com.

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.

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EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Publication of this document	30 April 2020
Last day of dealing of Existing Share Capital	15 May 2020
Re-Admission becomes effective and dealings in the Existing Share Capital expected to recommence on AIM	8.00 a.m. on 18 May 2020

Notes:

Reference to times above are to London time unless otherwise stated. Each of the times and dates set out in the timetable above mentioned throughout this document may be adjusted at the absolute discretion of the Company and Strand Hanson. In the event of a change, the Company will make an appropriate announcement to a Regulatory Information Service giving details of any revised dates and details of the new times. Shareholders may not receive any further written communication.

KEY STATISTICS

Existing Share Capital	996,408,412
Closing mid-market price on 29 April 2020 (being the Latest Practicable Date)	8.00 pence
Market capitalisation as at Last Practicable Date	US$99.6 million
Percentage of the Existing Share Capital held by the Directors	3.24 per cent.
Percentage of Ordinary Shares not in public hands (as defined by the AIM Rules)	7.60 per cent.
ISIN for the Ordinary Shares	GB00BP41S218
SEDOL for the Ordinary Shares	BP41S21
Trading symbol for the Ordinary Shares on AIM	SAVE
Legal Entity Identifier	2138002YCJORSFH5YR43

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* David Clarkson – *Non-Executive Director* Mark Iannotti – *Non-Executive Director* David Jamison – *Non-Executive Director* Michael Wachtel – *Non-Executive Director*
Company secretary	Isatou Semega-Janneh 40 Bank Street London E14 5NR
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
Joint Brokers	Mirabaud Securities Limited 10 Bressenden Place London SW1E 5DH Numis Securities Limited The London Stock Exchange Building 10 Paternoster Square London EC4M 7LT
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 Bracewell (UK) LLP Tower 43 25 Old Broad Street London EC2N 1HQ
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 Plot 98 Adeola Odeku Street Victoria Island Lagos, Lagos State Nigeria

Solicitors to Strand Hanson	FieldFisher LLP Riverbank House 2 Swan Lane London EC4R 3TT
Reporting Accountants to the Company	BDO LLP 55 Baker Street London W1U 7EU
Financial PR	Celicourt Communications Limited Orion House, 5 Upper St Martin's Lane London WC2H 9EA
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-energy.com

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 Holdco	Accugas Holdings UK PLC, a company incorporated under the laws of England and Wales with registered company number 11950135, whose registered office is at 40 Bank Street, London, United Kingdom, E14 5NR;
Accugas Holdco Senior Secured Notes	the US$20 million notes issued by Accugas Holdco as more fully described in Part 2 and Part 11 of this document;
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	Accugas UK Limited, a company incorporated under the laws of England and Wales with registered company number 12257421, whose registered office is at 40 Bank Street, London, United Kingdom, E14 5NR;
Accugas Midstream Business	the business currently operated by Accugas Limited, an indirect subsidiary of Accugas HoldCo, comprising a 200 MMscfpd gas processing facility and c. 260 km gas pipeline network and associated gas processing infrastructure;
Accugas Term Facility	the US$370.8 million term facility provided to Accugas Limited (as amended and restated) and as more fully described in Part 2 and Part 11 of this document;
Acquisition	the acquisition by the Company of the Nigerian Assets, further detail on which is disclosed in 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;
AIIM	African Infrastructure Investment Fund 3 GP Proprietary Limited, a vehicle managed by African Infrastructure Investment Managers Limited;
AIIM Transaction	the issue to AIIM of a 20 per cent. interest in each of Accugas HoldCo and Uquo HoldCo;
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, as amended and restated from time to time;
Board	the board of directors of the Company from time to time;
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);
CGCL	Calabar Generation Company Limited, the operating company of the Calabar power station;
CGG	CGG Services (UK) Limited, the author of the Nigeria Competent Person's Report and the Niger Competent Person's Report;
CNPC	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 Energy PLC, a company incorporated in England and Wales with registered number 09115262, whose registered office is at 40 Bank Street, London, E14 5NR (and whose name was changed from Savannah Petroleum PLC on 16 April 2020);
Completion	the completion of the Acquisition and Capital Restructuring pursuant to the Implementation Agreement following receipt of all required consents, including Ministerial Consent and NFCCPC Consent, as announced by the Company on 15 November 2019;
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;
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;
Dec 2017 Admission Document	the AIM Admission Document published by the Company on 22 December 2017;
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 5 of this document;
DPR	the Department of Petroleum Resources, a department of the MPR;
DSA Facility	the US$11.3 million facility provided to Accugas Limited as more fully described in Part 2 and Part 11 of this document;
EBT	the Savannah Petroleum Employee Benefit Trust, constituted by a trust deed dated 9 February 2015;
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;
ESMA Recommendations	European Securities and Markets Authority's update of the Committee of European Securities Regulators' recommendations for the consistent implementation of the EU Regulations on Prospectuses;
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 made by the Company in January 2018 to effect the acquisition of the SSNs issued by SEFL;
Existing Group	the Company and its subsidiaries prior to Completion;
Existing Share Capital	the 996,408,412 Ordinary Shares as at the date of this document and on Re-Admission;
Exoro	Exoro Holding B.V., a company incorporated in the Netherlands with registered number 2730262 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 Bilateral Facility	the facility agreement dated 23 June 2015 between, inter alia, SEFL and SEL (as borrowers) and the Agent (as defined therein);
FOL Transaction	the transaction between SUGL and Frontier, under which SUGL acquired 100 per cent. of the gas project at the Uquo Field (including associated condensate production), Frontier relinquished operatorship of the Uquo CPF to Accugas Limited, and Frontier acquired 100 per cent. of the oil project at the Uquo Field;
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;

FSMA	the Financial Services and Markets Act 2000 of the UK (as amended), including any regulations made pursuant thereto;
FUN Group	Frontier Oil Limited, Universal and Network Exploration & Production Company Nigeria Limited;
FUN Manifold	the facilities for storing, handling and exporting crude oil on behalf of the FUN Group from the Uquo, Stubb Creek and Qua Iboe fields to QIT;
Group	the Company and its subsidiaries from time to time;
IFRS	International Financial Reporting Standards, as adopted by the European Union;
Implementation Agreement	the agreement dated 4 February 2019 as amended on 7 November 2019 between the Company, Seven Energy and certain creditors of the Seven Group to document the legal terms and steps on which the Transaction took place, as more fully described in Part 2 of this document;
Latest Practicable Date	29 April 2020, 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 or **LTIP**	the Company's initial long-term incentive plan, which was established on 28 November 2014, further details on which are contained in paragraph 4 of Part 10 of this document;
Marginal Field Guidelines	the Guidelines For Farm-out And Operation of Marginal Fields 2001 published by the DPR in Nigeria;
Market Abuse Regulations	Market Abuse Regulation (Regulation 596/2014);
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 Nigerian Minister of Petroleum Resources to the Acquisition in accordance with the Petroleum Act and the Oil Pipelines Act, as announced by the Company on 19 August 2019;
Mirabaud	Mirabaud Securities Limited of 10 Bressenden Place, London, SW1E 5DH, the Company's joint broker;
NDPHC	the Niger Delta Power Holding Company, the owner of, inter alia, the Alaoji power station and Calabar power station;

NERC	the Nigerian Electricity Regulatory Commission;
Niger CPR or **Niger Competent Person's Report**	the competent person's report on the Group's Nigerien assets, as set out in Part 9 of this document;
Nigeria CPR or **Nigeria Competent Person's Report**	the competent person's report on the Group's Nigerian assets, as set out in Part 8 of this document;
Nigerian Assets	the interest in the Uquo Gas Project owned by SUGL, the interest in the Stubb Creek Field owned by Universal and the interest in the Accugas Midstream Business owned by Accugas Limited;
NFCCPC	Nigerian Federal Competition and Consumer Protection Commission;
NFCCPC Consent	NFCCPC's consent to the Company's acquisition of 62.5 per cent. of Universal;
NGN or Naira	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;
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;
Pounds Sterling or **£**	pounds sterling, the lawful currency of the UK from time to time;
Promissory Note	the US$11.5 million note issued by Accugas Holdco as more fully described in Part 2 and Part 11 of this document;
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, as amended from time to time;
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	the re-admission of the Existing Share Capital 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;
SAA	the strategic alliance agreement between NPDC and SEPL dated 15 September 2010;
Savannah Niger	Savannah Petroleum Niger 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, the R3/R4 PSC and the proposed R1/R2/R4 PSC;
SEC	US Securities and Exchange Commission;
Second Bilateral Facility	the facility agreement dated 26 June 2015 between, inter alia, SEFL and SEL (as borrowers) and the Agent (as defined therein);
Securities Act	US Securities Act of 1933, as amended, and the rules and regulations promulgated thereunder;
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;
SEL	Seven Energy Ltd., a company incorporated in Bermuda with registered company number 37778;

Senior Managers	Antoine Richard, Yacine Wafy, Chris Thomas and Jessica Ross;
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 Group	Seven and its subsidiary entities;
Shareholders	the holders of Ordinary Shares from time to time;
Share Options	options to subscribe for new Ordinary Shares;
Shell	Royal Dutch Shell PLC;
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;
SP1L	Savannah Petroleum 1 Limited, a company incorporated in Scotland with registered number SC453751, whose registered office is at 50 Lothian Road, Festival Square, Edinburgh, Midlothian, EH3 9WJ;
SPDC	Shell Petroleum Development Company of Nigeria Limited;
SPNL	Savannah Petroleum Nigeria Limited, a company incorporated under the laws of England and Wales with registered company number 11290084;
SSNs	the 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;
SUGL Notes	the US$105 million notes issued by SUGL as more fully described in Part 2 and Part 11 of this document;
SUGL Working Capital Facility	the NGN4.8 billion working capital facility provided to SUGL (as amended and restated) and as more fully described in Part 2 and Part 11 of this document;

Supplementary Plan	the Company's supplementary long-term incentive plan, further details on which are contained in paragraph 4 of Part 10 of this document;
Takeover Code	the UK City Code on Takeovers and Mergers (as amended from time to time);
Target Companies	Accugas Limited, Seven Uquo Gas Limited, Universal Energy Resources Limited and Exoro Holding B.V., being the holders of the Nigerian Assets;
Transaction	the Acquisition 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 or **Lafarge**	Lafarge Africa plc (previously known as 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 Ro. d, Uyo, Akwa Ibom State, Nigeria;
Upstream GSA	the gas sales agreement dated 6 November 2019 between SUGL as seller and Accugas Limited as buyer relating to gas produced at the Uquo Field;
Uquo CPF	the 200 MMscfpd 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 Gas Project	the gas project at the Uquo Field;
Uquo HoldCo	Savannah Petroleum (Uquo) Limited, a company incorporated under the laws of England and Wales with registered company number 12292632, whose registered office is at 40 Bank Street, London, United Kingdom, E14 5NR;
Uquo JOA	the joint operating agreement between Frontier and SUGL dated 9 January 2007 as amended from time to time, more particularly described in paragraph 2.3 of Part 11 of this document;

Uquo JV	the joint venture between SUGL and Frontier in connection with the Uquo Field which governs the terms of the FOL Transaction on an ongoing basis;
US Dollar, **US$** or **$**	the legal currency of the United States from time to time;
World Bank Partial Risk Guarantee or **Partial Risk Guarantee**	the guarantee of the payment obligations under the downstream GSA between Accugas Limited 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.

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 usage 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);
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;
Bnscfpd	billions of standard cubic feet per day;
Boe	barrels of oil equivalent. One barrel of oil is approximately the energy equivalent of 6Mcf of natural gas;
Bopd	barrels of oil per day;
Bscf	billion standard cubic feet; 1 Bscf is approximately equal to 166,667 Boe or 23,618 tonnes of oil equivalent;
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 145 to 65 Mybp;
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 mast drawworks, and attendant surface equipment of a drilling or workover unit;
EBITDAX	earnings before interest and tax, depreciation, amortisation and exploration expense;
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;
GIIP	gas initially in place;

gross resources	the total estimated petroleum that is potentially recoverable from a field or prospect;
GSA	gas sales agreement;
HSE	health, safety and environment;
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;
Kboepd	thousands of barrels of oil equivalent per day;
Kbopd	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);
LTI	lost time injury;
M	thousand;
m	meter;
Mboed	thousands of barrels of oil equivalent per day;
Mcf	thousand cubic feet of natural gas;
MM	million;
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;
MMstb	millions of standard stock tank barrels of oil;
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 – 1 Boe = 6,000Scf;
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;
permeability	a measure of the ability of a material (such as rocks) to transmit fluids;
Petroleum	a generic name for hydrocarbons, including crude oil, natural gas liquids, natural gas and their products;
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;
PSTM	Pre-Stack Time Migration;
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);
RFT	repeat formation test;
scf	standard cubic feet;
scm	standard cubic meter;

scmd	standard cubic meter per day;
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;
STOIIP	stock tank oil initially in place;
Tscf	trillion standard cubic feet;
Tertiary	geological strata formed during the period from 65 to 1.8 Mybp;
TVDSS	true vertical depth sub-sea;
up-dip	up the plane of the dip;
Upper Cretaceous	period of geological time, approximately 100 to 65 Mybp;
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.

PART 1

INFORMATION RELATING TO THE COMPANY

You should read the whole of this document and not just rely on the information contained in this Part 1. In particular, you should consider carefully the "Risk Factors" set out in Part 3 of this document.

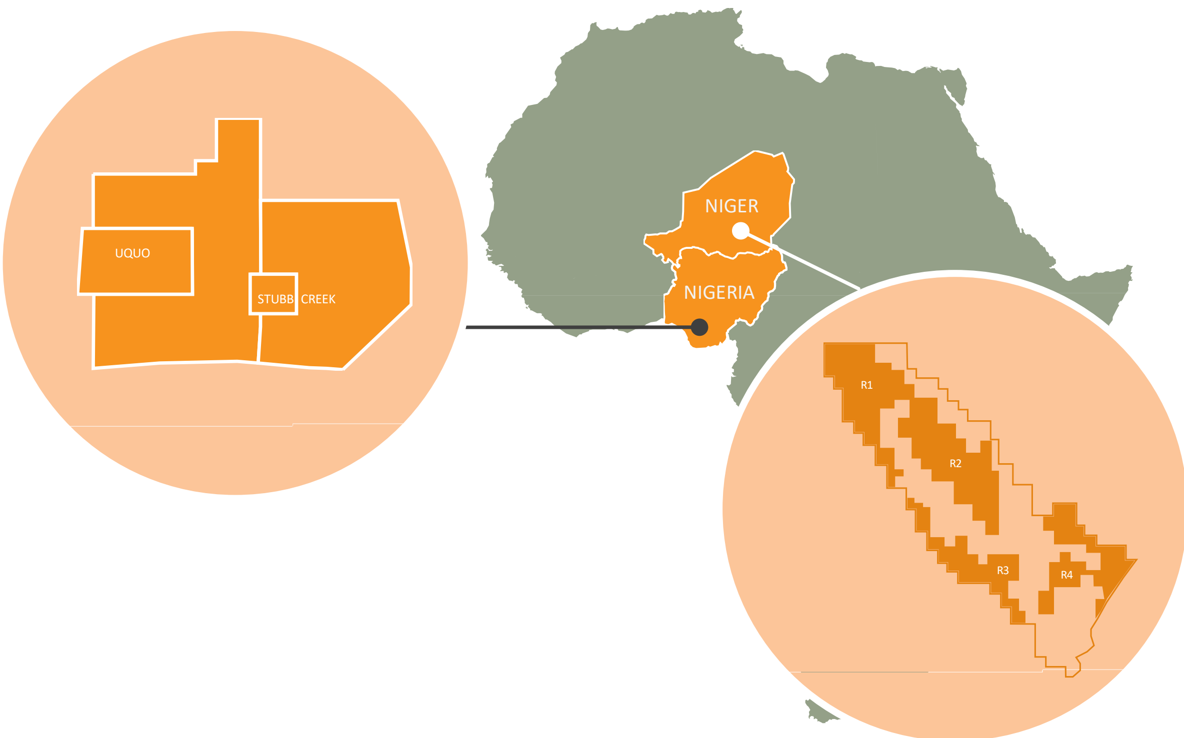
1. Introduction

The Company is the holding company of the Enlarged Group and currently operates from offices in the UK (London), Nigeria (Lagos, Abuja, Eket and Uyo) and Niger (Niamey). The Enlarged Group in its current form resulted from a reverse takeover transaction by the Company, pursuant to Rule 14 of the AIM Rules for Companies, of the Nigerian Assets. The Transaction is more fully described in this Part 1 and Part 2 of this document.

The Company has two high-quality and high-growth business units located in Nigeria and Niger. In Nigeria, following the Acquisition, the Company has a significant interest in a large-scale integrated gas production and distribution business which is capable of supplying gas to c. ten per cent. of Nigeria's power generation capacity. In Niger, the Company holds two significant licences in the country's main petroleum basin.

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 in new equity. Since being admitted to trading on AIM, the Company has raised a further US$203 million through the issue of new Ordinary Shares, which funded the acquisition of the R3/R4 PSC, further exploration activity on the Savannah PSCs (including the acquisition/processing of 806 km^2 of 3D seismic and a five well exploration drilling campaign which delivered a 100 per cent. success rate) as well as the Acquisition.

Figure 1, Location of Company's Nigerian and Nigerien assets



Nigeria

The Company acquired the Nigerian Assets from Seven Energy in November 2019 following completion of the Transaction.

The Nigerian Assets comprise interests in two large-scale oil and gas fields, the Uquo Field and the Stubb Creek Field, with net 2P Reserves and net 2C Resources of 71.0 MMboe and 58.6 MMboe respectively, and the Accugas Midstream Business. Gas produced from the Uquo Field is processed and transported through Accugas's infrastructure, which includes a 200 MMscfpd processing facility and a c. 260km pipeline network connecting the Uquo Field to its end user gas customers, including the Calabar and Ibom power stations, that comprise ten per cent. of Nigeria's available power generation capacity, and the Unicem cement factory.

Figure 2, Location of Company's Nigerian Assets

Source: Savannah, 2019

Niger

The Company's licence interests in Niger are located in the highly prospective Agadem Rift Basin in South East Niger covering an area of approximately 13,655km^2. 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 runs through Niger, Chad, Sudan, South Sudan and also Nigeria, with over 6 bnbbls of oil discovered to date. The Company's interests, which were acquired over the course of 2014 and 2015, cover c. 50 per cent. of the ARB, and of the original Agadem PSC Area which was compulsorily relinquished by CNPC in July 2013. Following a successful exploration drilling programme in 2018 on the R3 East portion of the R3/R4 PSC ("**R3 East**"), and in accordance with the terms of the R3/R4 PSC, the Company relinquished the R4 area of this PSC. The Company has agreed with the Ministry of Energy and Petroleum that the R4 area will be combined with the R1/R2 PSC Area into a new PSC, which would see the Group retaining the full acreage position previously covered by the R1/R2 PSC and the R3/R4 PSC. As later described in this section, formalisation of this arrangement is ongoing.

The Company has proven its ability to operate in Niger, having acquired a 36,948km FTG Survey over the ARB as well as 806 km^2 3D seismic over part of the R3 portion of the R3/R4 PSC Area. In 2018, Savannah launched its maiden exploration drilling campaign on the R3 East portion of the R3/R4 PSC, delivering five discoveries from five wells. The Company has a strong operational track record in Niger, with all projects having been delivered with no lost-time incidents and ahead of budgeted time. Current focus projects in Niger are the delivery of first production and cash flows from the planned R3 East early production scheme, and preparation for the Company's next drilling campaign where further material resource additions are expected through targeting some of the 146 potential exploration targets which have been identified on the Savannah PSC areas. Subject to market and financing conditions, Savannah expects both of these projects to be launched in 2020 and believes that its existing (and potential further) Niger discoveries have the potential to deliver meaningful cash flows to the Group in the future.

Further details on the Nigerian Assets are set out in this Part 1 and in Part 4 and Part 8 of this document. Further information on the Company's Niger assets is set out in this Part 1 and in Part 5 and Part 9 of this document. Further details of the Transaction and the Capital Restructuring are set out in this Part 1, Part 2 and Part 11 of this document.

2. Acquisition of the Nigerian Assets

Since the Company first announced the proposed transaction with Seven Energy and certain of the financial creditors of Seven Energy in 2017, the terms of the Transaction and the interests being acquired by the Company as described in the Dec 2017 Admission Document were amended.

The key differences between the Acquisition as it was initially described in the Dec 2017 Admission Document and as it was subsequently amended (as described by the Company's RNSs of 20 September 2018, 21 December 2018 and 1 October 2019) are summarised in Figure 3 and described in further detail below.

Figure 3, Summary of Interests Acquired by the Company Following Transaction Amendments

	December 2017	*Upon Transaction Completion*	*Comment*
Uquo Gas & Condensate	87.7%	80.0%[1]	Amended per FOL Transaction and AIIM Transaction
Uquo Oil	85.0%	–	Amended per FOL Transaction
Universal (Stubb Creek)	62.5%	100.0%[2]	Acquisition of Universal minority shareholders
Accugas Midstream Business	20.0%	80.0%[3]	Amended per FOL Transaction and AIIM Transaction

Notes

1. The Uquo interests reflects the Company's net economic interest in the Uquo Field after taking into account the 20 per cent. equity interest held by AIIM, via African Upstream Holdings Mauritius, in Uquo HoldCo, the holding company of SUGL;
2. This represents the Company's economic interest in Universal, which holds a 51 per cent. operating interest in the Stubb Creek Field; and
3. This represents the Company's shareholding interest in Accugas HoldCo, which is the holding company for the Accugas Midstream Business.

The Directors took the decision to make these amendments, whilst recognising that they would result in a delay to the completion of the Transaction, as the Board believes the amendments represent material positives for the Enlarged Group going forward. In aggregate, the amendments give the Company control of the integrated Accugas Midstream Business and the Uquo Gas Project (affording Savannah increased operational control across the gas value chain) and the Directors believe that the amendments are demonstrably NPV and cash flow accretive and significantly increase the upside exposure of Savannah's Nigerian gas business given the current unutilised processing and transportation capacity of the Accugas Midstream Business.

Under the final terms of the Acquisition and the AIIM Transaction, the Company acquired the following assets:

A. *80 per cent. economic interest in the Uquo Field gas project*

Savannah holds an indirect 80 per cent. economic interest in the exploration, development and production of gas within the Uquo Field through its 80 per cent. equity ownership interest in Savannah Petroleum (Uquo) Limited and its wholly owned subsidiary. Seven Uquo Gas Limited, which has a 100 per cent. economic interest in the Uquo Gas Project (including associated condensate production). SUGL holds responsibility for all operations of the gas project at the Uquo Field, including control of gas-related capital investment projects and day to day gas operations.

The remaining 20 per cent. economic interest in the Uquo Field is held by African Infrastructure Investment Managers, a leading African-focused private equity firm, through its 20 per cent. equity interest in Savannah Petroleum (Uquo) Limited.

Further details about AIIM are included in paragraph 8 of Part 1 of this document.

Changes to the Acquisition structure since the Dec 2017 Admission Document

At the time of the Dec 2017 Admission Document, it was intended that the Company would acquire a 40 per cent. participating interest in the Uquo Field, through the acquisition of SUGL. At that time, the Company would have had an effective 87.7 per cent. gas and 85 per cent. oil revenue interest in the Uquo Field under the terms of the joint operating agreement and technical services agreement between SUGL and Frontier (which held the balance of interest in the Uquo Field) in which SUGL acted as the technical and funding partner to Frontier and as project manager for the development of the Uquo Field.

The Company announced on 1 October 2019 that Frontier, SUGL and Accugas had entered into final long-form documentation in relation to the restructuring of economic interests in the Uquo Field and the operatorship of the Uquo CPF, in line with the Company's RNS dated 20 September 2018. Pursuant to the terms of the FOL Transaction, Frontier, SUGL and Accugas Limited agreed to undertake a transaction known as the FOL Transaction.

As previously stated by the Company, the FOL Transaction has led to a significant reduction in SUGL's capital investment plans, where approximately US$35 million was anticipated to be spent on oil related capital expenditure at the Uquo Field following completion of the Transaction, and the consideration of the FOL Transaction is therefore expected to be offset against associated reductions in capital expenditure.

The terms of the FOL Transaction provided that, whilst Frontier's and SUGL's participating interest in the Uquo Field remains at 60 per cent. and 40 per cent. respectively, SUGL is granted economic ownership and control of 100 per cent. of the gas project at the Uquo Field (including associated condensate production), Accugas Limited is granted operatorship of the Uquo CPF and Frontier is granted economic ownership and control of 100 per cent. of the oil project at the Uquo Field, all with an economic effective date of 31 August 2018.

Under the terms of the FOL Transaction, SUGL made an advance payment of cash calls of US$20 million to Frontier on the completion of the FOL Transaction. A further US$14.13 million of advance cash calls is payable in Naira across three yearly instalments, with the first instalment of US$5 million due twelve months following the completion of the Transaction, the second instalment of US$5 million due twenty-four months following completion of the Transaction and the final instalment of US$4.13 million due thirty-six months following completion of the Transaction. The three yearly instalments payable to Frontier are subject to a deduction of NGN 1.2 billion in respect of gas sales proceeds received by Frontier between 31 August 2018 and the date of completion of the FOL Transaction (net of royalties paid by Frontier in respect of the corresponding volumes of gas).

As previously announced, AIIM's 20 per cent. ownership of Savannah Petroleum (Uquo) Limited was formalised on 8 July 2019 with the signature of final long-form documentation.

B. ***100 per cent. economic interest in Universal, which holds a 51 per cent. operating interest in the Stubb Creek Field***

Savannah holds a 51 per cent. interest in the Stubb Creek Field. This interest is held via a 100 per cent. economic interest in Universal, which in turn holds a 51 per cent. interest in the Stubb Creek Field. The remaining 49 per cent. interest in the field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited.

Changes to the Acquisition structure since the Dec 2017 Admission Document

At the time of the Dec 2017 Admission Document, it was intended that the Company would acquire a minimum 62.5 per cent. interest in Universal.

The Company announced on 20 September 2018 that an agreement had been reached for Seven Energy to acquire the remaining 37.5 per cent. minority shareholders' interests in Universal for total consideration of US$3 million, increasing the Company's effective participating interest in the Stubb Creek Field to 51 per cent. upon completion of the Transaction.

Prior to completion of the Transaction, a newly incorporated company within the Seven Group ("**Stubb Creek HoldCo**") acquired the 37.5 per cent. minority shareholders' interests in Universal. Upon completion of the Transaction, Stubb Creek HoldCo and the 62.5 per cent. interest in Universal otherwise held by the Seven Group were transferred to Savannah, such that the Company acquired a 100 per cent. economic interest in Universal and a 51 per cent. operating interest in Stubb Creek Field.

C. *80 per cent. interest in Accugas Midstream Business*

Savannah holds an 80 per cent. indirect interest in the Accugas Midstream Business, which owns and operates the 200 MMscfpd Uquo CPF and c. 260km gas pipeline network and related gas distribution infrastructure, as well as holding a number of gas sales agreements with downstream customers. The remaining 20 per cent. of the Accugas Midstream Business is held indirectly by AIIM.

Changes to the Acquisition structure since the Dec 2017 Admission Document

Previously, as described in the Dec 2017 Admission Document, the Company had entered into a conditional investment agreement pursuant to which AIIM, together with potentially one or more co-investors, would acquire an 80 per cent. interest in the Accugas Midstream Business with AIIM to invest at least US$45 million into the business in return for its equity interest. Pursuant to this conditional investment agreement, the Company would acquire a 20 cent. carried interest in the business.

As announced by the Company on 21 December 2018, the Company stated its intention to acquire an additional 60 per cent. interest in the Accugas Midstream Business, which would have the result of the Enlarged Group owning an 80 per cent. interest in the Accugas Midstream Business. On 8 July 2019, the Company signed final long-form documentation in respect of, *inter alia*, the AIIM Transaction. Pursuant to the Acquisition, the Company acquired a 100 per cent. indirect interest in Accugas Limited and, pursuant to the AIIM Transaction, immediately thereafter, new ordinary shares representing a 20 per cent. interest in Accugas HoldCo, the holding company of Accugas Limited, were issued to AIIM (via African Midstream Holdings Mauritius) with the effect that the Company maintained an 80 per cent. indirect interest in the Accugas Midstream Business.

AIIM acquired its 20 per cent. indirect interest in both Uquo HoldCo (see above) and Accugas HoldCo for a total cash consideration of US$54 million, which was transferred directly to the Company (on behalf of Accugas HoldCo and Savannah Petroleum (Uquo) Limited) upon completion of the AIIM Transaction. As a result of the transaction amendments, which were NPV and cashflow accretive, Savannah gained control of the Accugas Midstream Business thereby increasing the upside exposure of the Group to a rise in gas volumes and prices.

Proforma Net Assets of the Enlarged Group

The Unaudited Proforma Statement of Net Assets of the Enlarged Group following completion of the Transaction is set out in Part 7 of this document. A comparison of the proforma net assets of the Enlarged Group following the Transaction as initially described in the Dec 2017 Admission Document and the Transaction as subsequently amended and described in this document is summarised below.

Proforma Net Assets of the Enlarged Group	*Transaction US$000 Note 2*	*Dec 2017 Admission Document US$000 Note 1*
Non-current assets	1,224,342	455,030
Current Assets	163,417	66,046
Total Assets	**1,387,759**	**521,076**
Current Liabilities	210,772	29,669
Non-current liabilities	729,042	111,785
Total liabilities	**939,814**	**141,454**
Net assets	**447,945**	**379,622**

Notes

1. Proforma Net Assets of the Enlarged Group as at 30 June 2017
2. Proforma Net Assets of the Enlarged Group as at 30 June 2019

Further details on the Acquisition of the Nigerian Assets and the Transaction, and the Enlarged Group structure, are set out in Part 2 of this document.

Good standing opinions

It is noted that as a result of the COVID-19 outbreak, it has not been possible for the Company's Nigerian counsel to undertake, immediately prior to publication of this document, the necessary in person searches that are required in Nigeria to confirm the good standing of the Group's Nigerian licences and subsidiaries. The relevant searches were last completed in March 2020 by the Company's Nigerian counsel confirming the good standing of the local subsidiaries and pipeline licences as at that date. The Stubb Creek licence was confirmed to be in good standing in a letter from the DPR in February 2020 and the Uquo Field licence good standing confirmation is subject to the payment of a fee, the question of which is currently under negotiation between Savannah and the DPR (a matter which is further described in Risk Factor 5.13 in Part 3 of this document).

Whilst the Company has no reason to believe that the good standing of its Nigerian licences and subsidiaries will have changed between the date of the searches and the date of this document, it cannot rely on up to date searches to evidence this fact, and in the unlikely event that a successful challenge had been lodged, in this interim period, as to the good standing nature of the Company's assets in Nigeria, it may result in the Enlarged Group being required to halt development or production or operations or, ultimately, in the loss of such assets.

3. Key investment proposition

Under the guidance of Savannah's Board and management team, the Enlarged Group's business model is centered on the delivery of material long-term returns for its stakeholders through the sustainable development and ultimate monetisation of high-quality, high-potential energy projects.

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

Nigeria

- Principal gas transportation and distribution network in South East Nigeria, spanning an area which contains c. 10 Tscf of undeveloped gas reserves

[1] Futures price of US$59.3/bbl 2020, US$57.4/bbl 2021, US$56.9/bbl 2022, US$57.1/bbl 2023. NPVs shown on a maintenance adjusted "take or pay" basis, i.e. based on the amount of gas that Accugas' customers are obliged to purchase, take and pay for (or pay for if not taken).

- Independently assessed average expected base case net asset free cash flows before debt service of approximately US$130 million p.a. (2020-2023)[1];
- Existing infrastructure has significant spare capacity, and therefore there is strong operational gearing associated with the signature of new gas contracts, which are typically long-term in nature; and
- Strongly positioned to deliver further organic and inorganic upstream oil and gas projects.

Niger

- Near term first production and cash flow potential from the R3 East development;
- Significant exploration potential of over 6.7 Bnbbls unrisked best estimate Oil-Initially-In-Place independently assessed, with 146 mapped prospects and leads;
- Proven ability to successfully operate, cost efficiently, in country with a 100 per cent. exploration success rate on five wells drilled to date;
- Proximity of operations to existing large scale infrastructure, with current focus around potential creation of an early production system aiming to monetise up to 5 Kbopd of production; and
- Planned 2,000 km cross border pipeline network funded by CNPC and due for completion in 2021/22 increases potential export market.

Corporate

- Supportive, long-term oriented institutional shareholder base
- Focus on creating significant shared value and lasting benefits for all stakeholders; and
- Strong culture of governance and delivery.

4. The Capital Restructuring

As part of the Transaction, in February 2018 the Company acquired US$305,623,123 of Senior Secured Notes issued by Seven Energy Finance Limited for cash consideration of US$40,910,505.74 and the issue of 224,021,689 new Ordinary Shares. A further US$552 million of Seven Energy's existing indebtedness was restructured and has been re-instated as follows (and shown as a comparison with the capital restructuring as described in the Dec 2017 Admission Document):

Figure 4 – Seven Energy re-instated debt (US$ million)

	Accugas HoldCo $mn	*Accugas Limited $mn*	*SUGL $mn*	*Total $mn*
Senior Secured Notes	20	–	–	20
SUGL Notes	–	–	105	105
First Bilateral Facility	20	–	–	20
Second Bilateral Facility	–	–	–	–
Accugas IV Facility	–	371	–	371
DSA Facility	–	11	–	11
Working Capital Facility		–	13	13
Promissory Note	12	–	–	12
Total	**52**	**382**	**118**	**552**
Dec 2017 Admission Document	82	386	85	553

Note: Since Completion, US$40 million of the re-instated debt has been paid down by Savannah.

5. Information on Seven Energy

Seven Energy was 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 institutional and developmental finance investment groups and strategic industrial investors.

This capital and associated investment enabled Seven to create a business which comprised of interests in two large-scale oil and gas fields, Uquo and Stubb Creek, and the Accugas Midstream Business. Gas produced from the Uquo Field is processed and transported through Accugas' infrastructure, which includes a 200 MMscfpd processing facility and a c. 260km pipeline network connecting the Uquo Field to end users, including the Calabar and Ibom power stations and the Unicem cement factory. In addition to this, substantial investment was made under its separate SAA with NPDC (which Savannah did not acquire as part of the Acquisition) that facilitated a 6.8x increase in gross production at OMLs 4, 38 and 41.

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

- A loss of material cash flows from the SAA, as the long term shut-down of the Forcados oil export terminal in February 2016 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;
- Delays in the downstream customers, particularly the Calabar power station, coming online and the long term gas sales agreement becoming fully effective; and
- 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).

These external challenges occurred at near peak cumulative negative cash outflow and gearing for the Seven Group and resulted in Seven Energy defaulting on all of its debt instruments (amounting to approximately US$900 million, in aggregate) in early 2017 when discussions with Savannah in relation to the Acquisition commenced. During the Acquisition implementation period (2017-2019), cash flow and working capital within the Seven Group was tightly managed in order to maintain operations and to preserve the value of the group's assets during the course of the Capital Restructuring.

6. Nigerian Upstream Assets

The Nigeria upstream assets comprise the Uquo Field and Stubb Creek Field, both of which 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 prepared by CGG, the respected international geophysical consultancy, a summary of the gross and net 2P Reserves and 2C Resources and the expected asset free cash flows of the Uquo Field and the Stubb Creek Fields are set out below:

Figure 5, Summary of Gross and Net 2P Reserves and 2C Resources

	2P Reserves		*2C Resources*	
	Gross	*Net*	*Gross*	*Net*
Oil & Liquids (MMstb)				
Uquo	0.7	0.5	–	–
Stubb Creek	15.4	3.7	–	–
Gas (Bscf)				
Uquo	500.9	400.7	72.5	58.0
Stubb Creek	–	–	515.3	293.7
Total (MMboe)	99.6	71.0	98.0	58.6

Figure 6, Summary of expected net asset free cash flows from the Uquo Field, Stubb Creek Field and Accugas Midstream Business (see below table for Nigeria CPR key assumptions)

	Nigeria CPR Forecast Asset Free Cash Flow, Net (US$ million)
2020	104.2
2021	128.1
2022	141.3
2023	141.3
Average	**128.7**

CGG has conducted a review of the value of the Savannah's interests in the Uquo Field and the Stubb Creek Field, which has been incorporated in the Nigeria CPR. The base case NPV10, based on 2P Reserves, for Savannah's interests in the Uquo Field and the Stubb Creek Field have been assessed at US$227.7 million and US$56.7 million, respectively.

Key assumptions used by CGG in its analysis include Brent futures oil price (inflated at 2 per cent. p.a. from 2027)[2], contracted gas prices and Take or Pay ("**ToP**") volumes. For full details of the assumptions used by CGG in its analysis, please see the Nigeria CPR, as set out in full in Part 8 of this document, and as announced by the Company on 11 December 2019.

Uquo Field

Savannah holds an 80 per cent. interest in the exploration, development and production of gas within the Uquo Field through its 80 per cent. owned subsidiary SUGL. Pursuant to the FOL Transaction, SUGL is responsible for all operations of the gas project at the Uquo Field, including control of gas-related capital investment projects and day to day gas operations.

Under the Uquo JOA, which was amended to reflect the terms of the FOL Transaction on an ongoing basis with effect from 31 August 2018, SUGL and Frontier have separated the oil and gas operations at the Uquo Field such that:

- SUGL has 100 per cent. of the economic benefit of, shall retain all gas and associated condensate produced and gross proceeds from (including associated natural gas produced from the oil production), shall pay for all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the Uquo Gas Project; and
- Frontier has 100 per cent. economic benefit of, shall retain all crude oil produced and gross proceeds from, shall pay all costs, taxed and royalties, and take all risks, obligations and liabilities with respect to the oil production from the Uquo Field.

Discovered by Shell in 1958, the Uquo Field was awarded to Frontier in the 2003 Marginal Field round, with Seven Energy 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 has processing capacity of 200 MMscfpd and was 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 under the Upstream GSA to Accugas Limited, as SUGL's sole customer, at a current price of US$1.31/Mscf for 2020, which is expected to increase by a weighted average (based on DCQ volumes) of over five per cent. per annum over the next five 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 c. 10 km from the Uquo Field, under a crude offtake agreement with ExxonMobil Sales and Supply LLC.

[2] Futures price of US$59.3/bbl 2020, US$57.4/bbl 2021, US$56.9/bbl 2022, US$57.1/bbl 2023, US$57.7/bbl 2024, US$58.2/bbl 2025, US$58.9/bbl 2026.

The Uquo Field is, in the Board's opinion, a low-cost field, with CGG having assessed life of field gross capital and operating costs to be US$0.9/boe (US$0.15/Mscf) and US$1.5/boe (US$0.25/Mscf), respectively on a forward basis, in the Nigeria CPR. Near-term operational plans at the field include the drilling and completion of a gas production well, recompletion of an oil well as a gas producer and work over of the current gas production wells at an estimated cost of US$33.7 million.

Stubb Creek Field

Savannah has a 51 per cent. participating interest in the Stubb Creek Field. Savannah's interest is held via a 100 per cent. economic interest in Universal, which in turn holds a 51 per cent. interest in the field. The remaining 49 per cent. interest in the field is held by Sinopec. Universal is the operator of the Stubb Creek Field.

The commercial agreement in relation to the crude oil and natural gas at the Stubb Creek Field is allocated on the following terms:

Figure 7, Commercial agreement between Universal and Sinopec with respect to the Stubb Creek Field

	Crude oil		*Natural gas produced with crude oil*		*Non-associated natural gas*	
	Funding	*Profit*	*Funding*	*Profit*	*Funding*	*Profit*
Universal	20%	51%	20%	51%	50%	60%
Sinopec	80%	49%	80%	49%	50%	40%

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 c. 3 Kbopd.

The Stubb Creek Field is an oil asset, with a considerable (515 Bscf 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 oil is exported from the Stubb Creek Field to QIT, which is operated by ExxonMobil and sold under the terms of the ExxonMobil COSA, as detailed in Part 11 of this document.

The Board believes that the acquisition of the minority shareholders' interest in Universal, in addition to the acquisition of Seven's interest, materially further increases the Enlarged Group's reserves and resources and provides the Enlarged Group with control over Universal's cost structure and Universal's share of Stubb Creek cash flows.

It is anticipated in 2021 that the existing Stubb Creek EPF will be debottlenecked, to increase oil production capacity to c. 5 Kbopd. The total capital investment anticipated for this project, involving bringing two existing wells into production and drilling a downdip water disposal well, is estimated at US$28million. The gas Contingent Resources are currently expected to be developed in 2030, as the Uquo Field comes off plateau, and to be tied back to the Uquo CPF via a new 31 km pipeline. The development of the gas resources required to fulfil the current GSAs, includes drilling/completion of four gas wells and construction of the pipeline. The pipeline cost is to be borne by Accugas.

Further information on the Uquo Field and the Stubb Creek Field is set out in Part 4 and Part 8 of this document.

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 MMscfpd Uquo CPF, a c. 260km pipeline network and long-term GSAs with downstream customers. Accugas buys raw gas from its sole current supplier, 80 per cent. owned subsidiary of Savannah, SUGL, at a price of US$1.31/Mscf for 2020, and sells this gas to three separate customers in long term gas sales agreements at a weighted average price of US$3.88/Mscf for 2020. 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 8, Accugas Summary of Key Gas Sales Agreements

	Calabar Power Plant	*Unicem Cement Plant*	*Ibom Power Plant*
Length of contract	20 years	20 years	10 years
Contract end	Sept 2037	Dec 2031	Dec 2023
DCQ	131.0 MMscfpd	38.7 MMscfpd	19.7 MMscfpd
Take or Pay (ToP)	80%	80%	80%

Further information about the GSAs is included in Part 11 of this document.

CGG has conducted a review of the value of Accugas, which has been incorporated in the Nigeria CPR. The base case enterprise value (NPV10) for Savannah's 80 per cent. interest in the Accugas Midstream Business has been assessed at US$672.8 million.

The Uquo CPF consists of two identical gas processing trains, each designed to process up to 100 MMscpfd.

Accugas new customer plans

Accugas' historical focus has primarily been on high volume, but lower margin 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' business infrastructure. Going forward, Accugas intends to focus on new gas supply opportunities with both power station customers and new "low volume, high value" industrial customers whose typical alternative source of power is from higher cost diesel-fuelled generation, with Accugas' facilities able to reach three principal industrial activity hubs (the areas surrounding Calabar, Port Harcourt and Aba).

The Company announced on 21 December 2018 that Accugas had entered into an agreement with Calabar Generation Company Limited and NDPHC in relation to the supply of gas to the Alaoji power station (which, like Calabar NIPP, is owned by NDPHC). Alaoji is a 504MW gas fired power station which is connected to the Accugas pipeline network via the Ukanafun Manifold and NGC/Shell gas pipelines. Potential gas demand from the two NDPHC power stations at full dispatch is currently estimated to be 225 – 270 MMscfpd (versus current Calabar DCQ volumes of 131 MMscfpd), presenting Accugas with significant long-term gas sales growth potential.

The Company announced on 31 January 2020 that Accugas had entered into a new interruptible gas sales agreement ("**IGSA**") with First Independent Power Limited ("**FIPL**") in relation to the provision of gas sales to the FIPL Afam power plant ("**Afam**"). FIPL is an affiliate company of Sahara Group, a leading international energy and infrastructure conglomerate with operations in over 38 countries across Africa, the Middle East, Europe and Asia.

Afam has a current power generation capacity of 180MW. The FIPL IGSA envisages the supply of gas (produced by Uquo, with a maximum daily nominated quantity of 35 MMscfpd or approximately 5.8 Kboepd) by Accugas to Afam in order to augment its existing gas supply on an interruptible basis for an initial term of one year with the ability to extend upon mutual agreement. The commercial terms of the IGSA are expected to augment the weighted average profitability of the Accugas portfolio while Accugas' sales volumes, revenues and cash flows are expected to increase with no incremental capital expenditure.

Accugas continues to make good progress in relation to the negotiation of contracts to supply gas to several other potential new customers, expected to diversify customer-mix and sources of revenue.

8. Partnership with African focused private equity investor AIIM

The Africa focused private equity fund manager, African Infrastructure Investment Managers, acting through its AIIF3 fund (via African Midstream Holdings Mauritius and African Upstream Holdings Mauritius) has acquired a 20 per cent. interest in each of SUGL and Accugas.

AIIM, which is a subsidiary of Old Mutual Investment Group, is one of the longest running and largest infrastructure fund managers in Africa, with US$2.1 billion assets under management over seven funds which since 2000 have concluded investments in more than 60 portfolio companies with operations in 19 countries. AIIM has extensive Nigerian experience, with total invested, committed and earmarked capital of greater than US$300 million in country, the majority of which is in the power, energy and telecommunications sectors.

As a leading infrastructure manager across Africa, central to AIIM's investment objectives and processes is its commitment to responsible investment. In this regard, the environmental, social and governance (ESG) factors are fully integrated within AIIM's investment process to support the pursuit and creation of positive futures and obtaining sustainable returns. AIIM has a proven track record of providing strategic, commercial and financial expertise into infrastructure investment activities.

Savannah and AIIM have indirectly entered into shareholders' agreements and technical services agreements with SUGL and Accugas. Pursuant to the shareholders' agreements, Savannah has the right to appoint the management, three out of the five directors and the chairman of the board of each of Uquo HoldCo and Accugas HoldCo and the operating subsidiaries will have the same board composition.

9. Nigeria's Oil & Gas Industry

Overview of the oil industry

At the end of 2018, Nigeria's proven oil reserves were estimated at approximately 37.5 billion barrels, the second largest in Africa and eleventh largest reserves in the world[3]. In 2018 Nigeria produced on average 2.05 million barrels per day of oil[4]. Nigeria is the largest oil producer in Africa, with substantially all production coming from the Niger Delta region. As a member of OPEC since 1971, Nigeria has agreed to oil production limits that have varied over the years but are currently set at approximately 1.75 MMbbls per day although, historically, actual production has been largely unaffected by the quota system.

There has been a general trend for the International Oil Companies, particularly Shell, Total, Eni, Chevron, and ConocoPhillips, to sell their interests in marginal onshore and shallow water oil fields, mostly to Nigerian companies and smaller international oil companies, and to focus their investments on deepwater projects, which tend to have more favourable fiscal regimes to encourage investment.

Over the last few years, also in conjunction with an increased focus of the Nigerian 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 the majors who are gradually withdrawing from the Niger Delta. NNPC is the state-owned oil company and it, or its subsidiary NPDC, has interests in most joint ventures and production sharing contracts.

Overview of regulatory and fiscal regime

The upstream industry is governed by the DPR, which is part of the MPR. Fiscal terms in Nigeria vary, with concessions, production sharing contracts, production sharing agreements and service contracts related to oil and gas ownership and extraction in use.

Nigeria is pursuing a number of reforms targeted at restructuring its oil and gas industry. These initiatives include streamlining and revising obsolete laws, rules and policies that regulate operations in the industry. In 2008, the Nigerian government submitted to the National Assembly the PIB, which proposes various reforms. A revised version of the PIB was presented in late 2012, however, the PIB has not yet passed into law. Discussions to date with respect to the PIB have resulted in uncertainty and delayed oil investments and projects in Nigeria.

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[3] BP Statistical Review, 2019

[4] BP Statistical Review, 2019

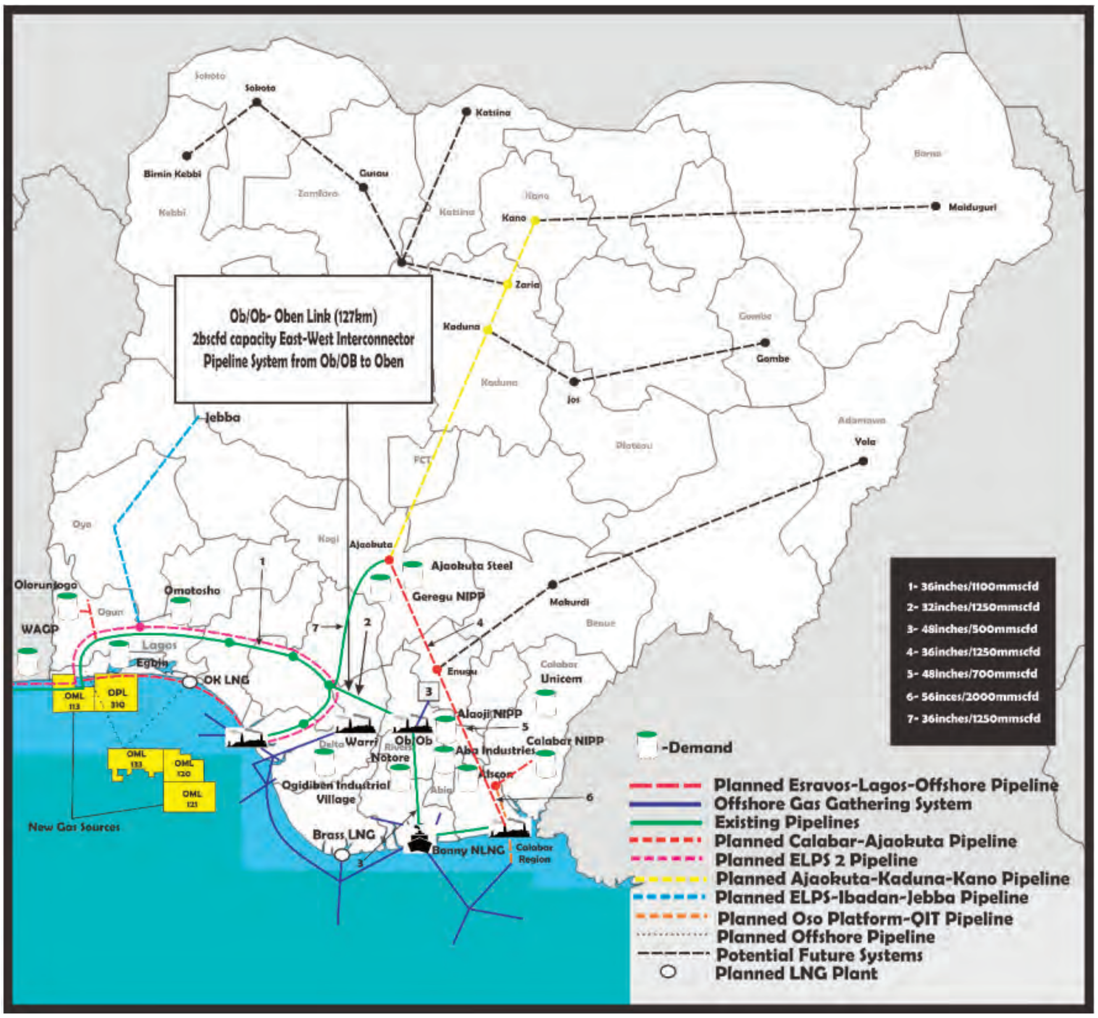
The key laws and regulations governing oil and gas activities in Nigeria include: (a) the 1999 Constitution (as amended); (b) the Petroleum Act; (c) the Petroleum (Drilling & Production) Regulations; (d) the Petroleum Profits Tax Act; (e) Deep Offshore & Inland Basin Production Sharing Contract Act; (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.

Gas production and development

As at end 2018, Nigeria is estimated to hold 188.8 Tscf of proved natural gas reserves, which makes it the tenth largest gas reserve holder in the world and the largest in Africa[5].

The majority of gas produced in Nigeria is considered associated gas, a by-product of oil production. In 2018 Nigeria's gas production was 4.8 Bnscfpd[6], which has significantly increased in recent times as a result of growing gas infrastructure projects to improve access and utilisation, but still represents only 1.3 per cent. of global gas production. Nigerian oil and gas industry participants have not yet capitalised on the country's substantial gas reserves to supply its domestic gas market, leaving significant potential for gas development.

Figure 9, Map of Nigeria showing Gas Demand and Infrastructure



Source: NNPC

[5] BP Statistical Review, 2019
[6] BP Statistical Review, 2019

Domestic Gas Market

The Nigerian government has stated that it sees the provision of adequate gas supply as a means of increasing industrial output and electricity supply, and hence economic growth, prosperity, and employment opportunities.

The development of gas supply for the domestic market has also been identified by successive Nigerian governments as a priority, as demonstrated by a number of reforms and initiatives. The Gas Master Plan, developed by NNPC in 2008, aimed to:

1. stimulate the multiplier effect of gas in the domestic economy;

2. position Nigeria competitively in high value export markets; and

3. guarantee the long-term energy security of Nigeria.

The Gas Master Plan also called for the construction of new cost competitive gas infrastructure, including pipelines and central processing facilities across the country.

In December 2016, the Federal Government launched the 7 Big Wins Initiative. This reinforced Nigeria's commitment to continue political support for reform of the oil and gas sector generally. 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 Gas Master Plan.

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.

Further information on the Nigerian oil and gas industry is set out in Part 4 of this document.

Please refer to Appendix A of this document for a more detailed overview of the legislative regime for Nigerian oil and gas companies.

10. The Nigerian opportunity

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 1950s, and a well-established oil service sector exists in country. Close to US$100 billion in net free cash flow has been generated by oil and 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.

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.

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$365 billion has been invested in Nigeria since 1965, which includes the drilling of over 3,700 exploration and appraisal wells and represents average oil and gas investment of c. US$7 billion per annum.

World class geology

At the end of 2018, Nigeria's proved oil reserves were estimated at approximately 37.5 Bnbbls of oil, the second largest in Africa and eleventh largest globally. Nigeria's proved gas reserves were estimated to stand at approximately 188.8 Tscf, 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 c. 300,000 km^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.

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 Yet-To-Find resources in the province at 25 Bnbbls (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 the divestment of their non-core assets as a result of increased need for capital consolidation, 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 over the course of the coming years. The Acquisition has seen the Company build and enhance its relationships with key stakeholders in country, as evidenced by, inter alia, the receipt of Ministerial Consent for the Transaction from His Excellency President Muhammadu Buhari, by the support received in relation to the Transaction from the Nigeria Sovereign Investment Authority and by the completion of the Capital Restructuring with a syndicate involving a number of the largest banks in Nigeria. It is expected that these relationships will facilitate a strong ability for the Enlarged Group to operate successfully and continue to grow in country.

11. The Nigerian Gas Market Opportunity

Nigeria has 188.8 Tscf of proved gas reserves, the largest in Africa and the tenth largest globally, yet only produces 4.8 Bnscfpd, the majority of which is exported as LNG. With a gas reserves to production ratio of approximately 110 years, the under-developed gas resources of Nigeria represent a significant opportunity to be exploited, in particular for the benefit of the domestic economy. The important distinction between oil and gas is that, while oil production and export provides a source of foreign exchange for the country, it does not offer the local economic multiplier benefits that gas does for the domestic market.

Nigeria's growing economy requires a reliable and affordable power supply. The Board believes that the potential for the development of gas resources in Nigeria is significant and exists across the value chain, from exploitation of underdeveloped gas fields, through construction and operation of gas processing and transportation infrastructure to developing the market for gas.

The gas distribution network in Nigeria is a significant factor holding back the development of gas. This lack of infrastructure discourages development of gas fields due to the high cost of building pipelines and the lack of availability likewise discourages potential major energy consumers from switching to gas.

The Board believes that the business model developed by the Accugas Midstream Business encapsulates this opportunity, having installed a 200 MMscfpd processing facility at the Uquo Field, and a c. 260km pipeline network, at a total cost of US$1 billion. Accugas is currently providing gas to power stations with current generating capacity of 675MW, equating to ten per cent. of Nigeria's available generating capacity.

Population growth and electricity supply

Nigeria is the largest economy in Africa with its population growing rapidly and forecast to reach 263 million people by 2030. The growing Nigerian population is urbanising rapidly and is already suffering chronic electricity shortages. Based on the country's GDP and global trends, electricity consumption could be expected to be four to five times higher than it is today. Over half of the population has no access to grid-connected electricity and those who are connected suffer extensive power outages. To improve the power sector, the Nigerian government has undertaken long-term structural reforms focused on privatising legacy power assets and instituting regulatory reform.

Nigeria has one of the lowest rates of electricity generation capacity per capita in the world, according to the Federal Government's Power Sector Recovery Program report of April 2017, Nigeria has 13,400MW of installed power generation capacity for a population of some 190 million people but less than 30 per cent. (4,000 MW) of this capacity is operational: approximately 85 per cent. of installed capacity is from 22 gas-thermal power plants and the remainder is hydro-electric. Non-availability of capacity is driven by gas supply, maintenance and repair issues. Transmission grid capacity is currently constrained to approximately 3,800 MW, reducing to around 3,400 MW after taking into account transmission losses. At present, the domestic and industrial demand for electricity is satisfied through an estimated 8 GW-14 GW generated by decentralised diesel generators, which are expensive to run and far more polluting than grid-based gas-fired power stations. After taking into account collection losses, approximately 46 per cent. of electricity generated is lost across the value chain through technical, commercial and collection issues.

Over the last fifteen years the Federal Government has made significant investments in the sector and undertaken a number of major reforms to target growth in power generation capacity. This commenced with the enactment of the 2005 Electric Power Sector Reform Act ("**EPSR Act**"), which provided for the unbundling of the national power utility company into six generation companies, eleven distribution companies and a national power transmission company, ahead of the planned privatisation of these companies. The Power Holding Company of Nigeria ("**PHCN**") was established as a transitional corporation for this purpose. The EPSR Act also established an independent regulator, the Nigerian Electricity Regulatory Commission ("**NERC**"). In 2005, the Federal Government also launched the National Integrated Power Projects ("**NIPP**") programme, an emergency intervention scheme to tackle the power problem in the country, funding the construction of ten new gas-fired power plants with a planned generating capacity of in excess of 4,700 MW. The NIPP programme is under the management of Niger Delta Power Holding Company and includes the Calabar power plant for which Accugas is the exclusive gas supplier.

The EPSR Act was complemented in 2008 by the Gas Master Plan and in 2010 by the Roadmap for Power Sector Reform. The stated objective of the Roadmap for Power Sector Reform was, among other objectives, to remove obstacles to private sector investment in the power sector (including through the provision of credit enhancement and the establishment of an appropriate pricing regime) and to permit the privatisation of existing generation and distribution companies. As part of the privatisation process, during the course of 2013 and 2014, the state owned PHCN was broken up with the generation companies and distribution companies being privatised and the Federal Government retaining ownership of the transmission company, Transmission Company of Nigeria ("**TCN**"),

TCN manages the transmission system with responsibility for the development and maintenance of transmission infrastructure, management of the flow of electricity throughout the power system from generation to distribution companies and administering power market rules. Nigeria's transmission network consists of 159 substations with a total (theoretical) transformation capacity of approximately 7,500MW and 20,000 km of transmission lines. The system is disrupted by frequent system collapses and outages.

In May 2010, the MPR Minister announced the implementation of a new gas-to-power price framework to encourage more gas production for electricity generation. Under the approved price framework, gas prices (for gas-to-power projects) progressively increased from US$0.60 cents per MMBtu to US$1.00 per MMBtu in 2011, US$1.50 per MMBtu in 2012 and US$2.00 per MMBtu in 2014.

In addition, the Nigerian government has taken a number of steps to support the development of Independent Power Producers ("**IPPs**"). In August 2011, a single buyer, Nigerian Bulk Electricity Trading ("**NBET**"), was established to buy electricity from the IPPs through Power Purchase Agreements and to sell it to the distribution companies. NBET, which became operational in early 2012, has a mandate to carry out contract management and bulk trading on behalf of the distribution companies until the industry stabilises, including in terms of demand and pricing.

Other measures taken by the Nigerian government to support development of the power sector include:

i. in August 2010, the creation by the Central Bank of Nigeria (**"CBN**") of a NGN 300 billion (approximately US$2 billion) Power and Aviation Sector Intervention Fund for investment in debentures to be issued by the Bank of Industry to finance power and aviation projects;

ii. in March 2011, the disbursement by the CBN of NGN 198 billion (approximately US$1.3 billion) of funds to the Bank of Industry for onward disbursement as discounted loans to the power and aviation sectors;

iii. in June 2012, the introduction of a new electricity tariff for the period from 2012 to 2017 with a view to encouraging potential investors who were concerned with the return on their investment under the former tariff regime to invest in the power sector; and

iv. in 2012 introducing new regulations to enable state and local governments, private investors and suppliers and communities to generate and distribute electricity for their exclusive consumption using existing electricity distribution networks or to invest in generating electricity for transportation through electricity distribution networks in areas without access to the grid or distribution network or areas with poorly serviced distribution networks.

The Federal Government on 22 March 2017 approved a Power Sector Recovery Plan in consultation with the World Bank Group. This comprised a NGN 701 billion payment assurance guarantee for the power sector, to be provided by the CBN as part of measures to tackle liquidity issues in the Nigerian power sector and to restore financial viability in the electricity market in its transitional phase and post-privatisation. This payment assurance programme was for an initial period of two years, but it was extended into 2020.

Nigeria's growing economy requires a reliable and affordable power supply. The development of gas for use in power generation and industry is expected to create multiple benefits for all stakeholders, including:

- Gas is a cleaner fuel than other hydrocarbons and is an abundant under-exploited local resource;
- Gas is a cheaper source of fuel than diesel, almost all of which is imported;
- As the gas pipeline system is developed so the economics and logistical issues in transporting gas from producers to consumers will ease, thus encouraging further consumers to switch to gas, in turn leading to development of gas resources for gas-to-power and industrial customers;
- Nigeria is actively promoting the reduction of flaring with some success, however the lack of gas infrastructure in country results in some 0.7 Bnscfpd of gas being flared. A developed gas infrastructure will accelerate this process;
- Reliable power will mean more jobs can be created; and
- The urbanising population is leading to a growing demand for cement and steel; both of these industries are highly energy intensive.

The potential for the development of gas resources in Nigeria is immense and exists across the value chain, from exploitation of undeveloped gas fields, through construction and operation of gas processing and transportation infrastructure to developing the market for gas.

Accugas' facilities and pipelines have significant spare capacity which, combined with the attractive price of gas as a source for power generation and industrial uses, provides a compelling investment opportunity.

Further information on the Nigeria gas market is set out in Part 4 of this document.

12. Overview of the Niger Oil & Gas Industry

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 PSC 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. Since acquiring its PSCs in 2008, CNPC has made 110 discoveries from 137 exploration wells (a success rate of 80 per cent.) and has established a 2P reserve base of c. 1 Bnbbls. In doing so, the Company believes CNPC clearly demonstrated the pro-business environment and ease of ability to operate in Niger, given the magnitude of the work programme pursued in a relatively short period of time, which included: (1) drilling more than 200 exploration, appraisal and development wells; (2) acquiring over 18,000 sq km of 2D seismic and 13,000 km^2 of 3D seismic; and (3) building a 463 km pipeline and the 20 Kbopd 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 licence area to CPC Corporation (the Taiwanese national oil company). In July 2013, the first period of exploration of the Agadem licence area by CNPC ended, and c. 50 per cent. of the acreage was returned to the public domain under the terms of CNPC's PSC with the Government of Niger. In July 2014, Savannah 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 resulting in Savannah having c. 50 per cent. of the Agadem Rift Basin under licence.

Elsewhere in Niger, the Algerian national oil company, Sonatrach, is active. Its affiliate, Sonatrach International Petroleum Exploration and Production ("**SIPEX**"), has a PSC over the Kafra licence area which is located in the north of Niger on the Algerian border. Following the acquisition of c. 1,700km 2D seismic, its first exploration well, Kafra-1, was drilled and reported as a significant discovery in April 2018, with an estimated STOIIP of up to 500 MMbbls. Kafra-1 was tested at c. 1,500 bopd.

Niger-Benin Export Pipeline

Niger's domestic oil consumption is relatively low (currently c. 10 Kbopd), meaning a significant proportion of existing production is exported, largely by truck and road to northern Nigeria. The majority of oil expected to be produced from future developments, including from CNPC's Agadem PSC Exclusive Exploitation Area 3 (the next major phase of development on the Agadem PSC), is expected to be exported.

In September 2019, a Transportation Convention was signed between CNPC and the Republic of Niger in relation to a crude oil export pipeline from the ARB to the Atlantic coast in Benin (the "**Niger-Benin Export Pipeline**" or the "**Pipeline**"). The Pipeline is expected to run for c. 2,000 km from the ARB in Niger to Port Seme on the Atlantic coast in Benin and is CNPC's largest ever cross-border crude oil pipeline investment.

The Transportation Convention sets out the contractual terms under which the Pipeline will be constructed and operated. It follows the signature in August 2019 of the Niger-Benin Pipeline Construction and Operation Agreement between CNPC and the Republic of Benin, as well as the upstream approval granted by the Republic of Niger to CNPC in June 2018 in relation to the Agadem PSC Exclusive Exploitation Area 3, the production from which is expected to be exported from Niger using the Pipeline.

CNPC has confirmed that the pipeline construction is expected to be complete in 2021/2022. Under the terms of the Savannah PSCs, the Petroleum Code of Niger and its Implementing Decree, Savannah is entitled in accordance with the Savannah PSC's terms to access the Pipeline and expects there to be spare capacity within the Pipeline to enable the monetisation of further discoveries on the Savannah PSCs made by the Company.

Niger oil service industry

Niger has an active and efficient oil service industry present and established in country. Great Wall Drilling Company Limited ("**GWDC**"), a large integrated petroleum engineering service provider (operating in 33 countries worldwide with 439 rigs), has operated in Niger for over 11 years and has drilled over 200 wells in the ARB. GWDC is a subsidiary of CNPC. It currently has 8 drilling rigs which are active in the ARB, and 4 workover rigs which are used for completion and well testing. GWDC has an excellent HSE record in Niger, with no serious accidents in its time operating in country and over 13 million man-hours worked without LTI.

BGP, one of the world's leading geophysical service companies and one of the world's largest land seismic companies (65 land crews operating globally), has also operated in Niger for over 11 years. Since coming to Niger, BGP has acquired over 18,000 km 2D seismic and over 13,000 km^2 3D seismic. BGP is also a subsidiary of CNPC.

Both GWDC and BGP have large logistics bases located in the ARB and are also joined by multiple local contractors who offer services including civil works, camp construction, desert transportation and logistics. Savannah has used the services of both GWDC and BGP as part of its work programmes.

Overview of regulation and fiscal regime

Please refer to Appendix B of this document for an overview of Niger's national legislative framework.

13. Overview of Niger Operations

The Company's license interests in Niger are located in the highly prospective Agadem Rift Basin in South East Niger covering an area of approximately 13,655 km^2. The ARB is comparable in scale to the North Sea rift system, and forms part of the Central African Rift System. The Company's interests, which were acquired over the course of 2014 and 2015, cover c. 50 per cent. of the ARB. Following a very successful exploration drilling programme in 2018 on the R3 East portion of the R3/R4 PSC, and in accordance with the terms of the respective PSCs, the Exclusive Exploration Authorisation on the R3/R4 PSC was renewed for a further two year term expiring 31 August 2021 and the Company relinquished the R4 area of the R3/R4 PSC. The initial term of the Exclusive Exploration Authorisation on the R1/R2 PSC has expired however, the Company has agreed with the Ministry of Energy and Petroleum that the R4 area will be combined with the R1/R2 PSC Area into a new PSC (the "**R1/R2/R4 PSC**") to be issued under the Petroleum Code 2017, thus retaining the full acreage position previously covered by the R1/R2 PSC and the R3/R4 PSC. The new R1/R2/R4 PSC covering the R1, R2 and R4 areas is subject to approval by the Council of Ministers and is expected to be formally awarded to Savannah on payment of the signature bonus and a fee in relation to the Government's expenses incurred in connection with the signing of the R1/R2/R4 PSC. The Directors expect that the Council of Ministers approval will be forthcoming shortly after publication of this document. Please refer to Appendix C for the key terms of the Savannah PSCs.

Savannah's stated business model in Niger is to discover material oil resources for a low finding cost relative to the expected net present value per barrel of the cash flows which it ultimately expects to yield from these discoveries. The Company's assessment of the historic ARB finding cost is c. US$1/bbl versus an expected net present value of c. US$5/bbl for a generic discovery. This business model is underpinned by three core views, being that:

1. The Company's PSC areas are technically low risk – the Company believes that large portions of its Niger PSC areas are analogous to that of the neighbouring Agadem PSC area, which has seen 110 oil discoveries from 137 exploration wells drilled on it to date (an 80 per cent. success rate) and that therefore the Company's exploration activities on its acreage may see similar repeatable exploration success.
2. The ARB is an established oil and gas jurisdiction conducive to successful operations: The ARB operating environment is proven, with established logistics and service company networks, giving Savannah confidence to deliver exploration, development and production projects. For example, the established service companies in the ARB have acquired over 18,000 km 2D and 13,000 km^2 3D seismic, drilled over 200 wells and built production, pipeline and refinery facilities.
3. Commercialisation of ARB discoveries is relatively straightforward: The ARB has existing downstream infrastructure in place and as noted above, the country has plans for export infrastructure to be installed over the coming years, most notably through the Niger-Benin Export Pipeline. First oil was delivered on the neighbouring Agadem PSC from a standing start three years from license award (including the construction of a new 463 km pipeline and associated refinery). Further, an appropriate legal framework for sharing third party infrastructure exists in Niger.

Exploration drilling campaign

Following the acquisition of 806 km^2 high-quality 3D seismic over the R3 East portion of the R3/R4 PSC area in 2016/2017, the interpretation of this dataset enabled the Savannah technical team to identify high-grade drilling targets for its exploration campaign on the area. GWDC acted as the Company's drilling contractor for the campaign, using the GWDC 215 rig ("**Rig GW-215**"). Prior to the commencement of Savannah's operations, Rig GW-215 had successfully drilled over 40 wells on the ARB and in total GWDC had drilled over 200 wells on the ARB, acquiring significant knowledge and experience of the geological and technical aspects of drilling in the area.

In April 2018, Savannah commenced its maiden exploration drilling campaign with the spud of the Bushiya-1 well, which delivered the Company's first discovery. This was followed by successes at Amdigh-1 and Kunama-1, leading to Savannah electing to exercise two individual well options and resulting in two further discoveries at Eridal-1 and Zomo-1. Following the Zomo-1 discovery, Savannah chose to conclude its campaign in order to allow its team to evaluate results from the campaign.

2018 was thus a validation of Savannah's Niger business model in which the exploration campaign resulted in the discovery of five new oil fields – Bushiya, Amdigh, Kunama, Eridal and Zomo – delivering a 100 per cent. exploration success rate and confirming the Company's belief that its PSCs are technically low risk.

Following the successful results of the five exploration wells drilled, Savannah Niger elected to commission Pre-Stack Depth Migration re-processing of the R3 East 3D seismic dataset, which showed an overall improvement in seismic imaging (better event continuity and fault definition) at all levels versus the existing Pre-Stack Time Migration dataset. The interpretation phase, which commenced in June 2019, will assist in confirming drilling targets to support the proposed early production scheme ("**EPS**") as well as identifying additional prospectivity in the deeper Yogou and Donga Cretaceous intervals. The Company also plans on proceeding with its planned Amdigh-1 and Eridal-1 well tests.

Route to market

Following Savannah's successful 2018 exploration drilling campaign, the Company has focused on commercialising the discoveries through an EPS which would accommodate the well-testing operation and seamlessly continue to produce oil into the existing local infrastructure. This would see oil produced from the discovery wells in the R3 East area of the R3/R4 PSC produced for sale into the Société de Raffinage de Zinder ("**SORAZ**") refinery. SORAZ is connected to the ARB via the 463 km Agadem-Zinder pipeline.

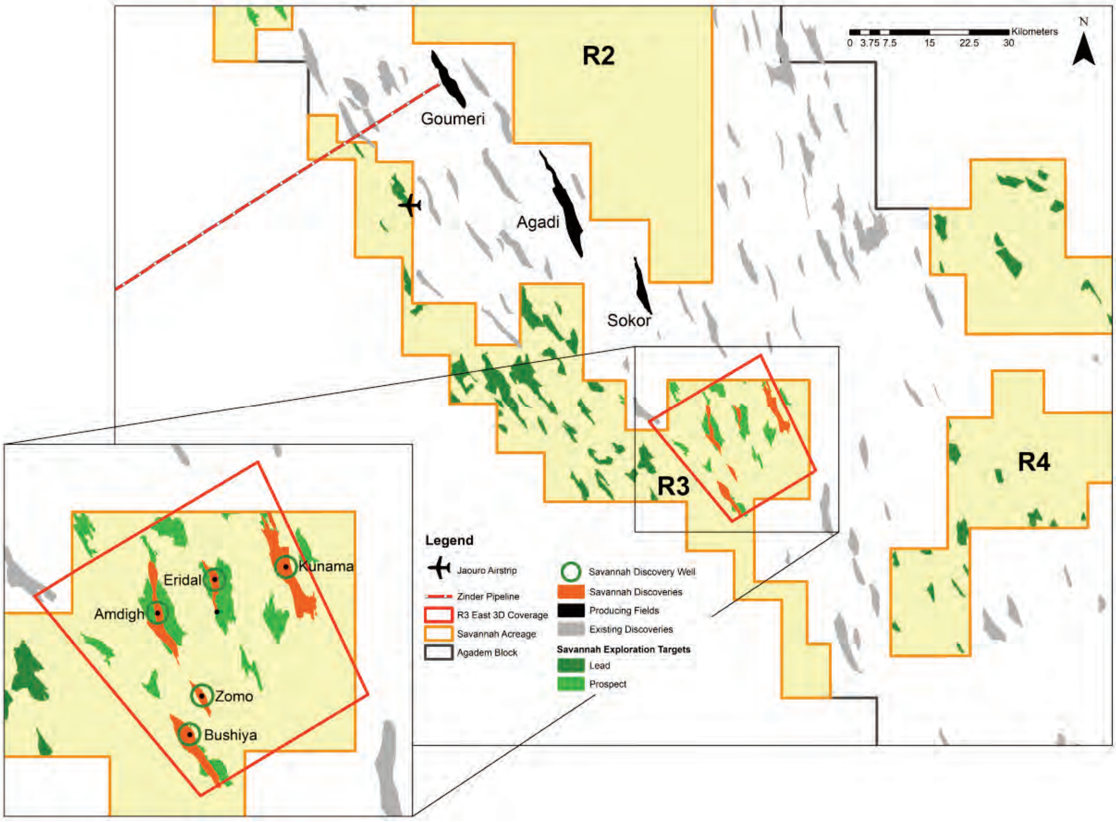
In August 2018, Savannah signed an agreement with the Republic of Niger in relation to the EPS. This agreement sets out how the Niger Government and Savannah intend to work together, and how Savannah will be supported by the Niger Government, in order to deliver first production from the EPS.

Achieving first oil from Savannah's discoveries in Niger is a key strategic priority for the Company and has the potential to deliver meaningful cash flows for the business, which the Company believe could occur within the next twelve months, market conditions and financing permitting.

The EPS is anticipated to be developed in two phases ("**Phase 1**" and "**Phase 2**"). Phase 1 is expected to see crude oil trucked from Amdigh 120 km to the Goumeri Export Station ("**GES**"), then piped to the SORAZ refinery via the existing pipeline and is anticipated to deliver plateau production of up to 1,500 bopd. Phase 2 foresees a pipeline being laid from Amdigh to the GES, with production expected to ramp up to 5,000 bopd.

As noted earlier, on 15 September 2019 CNPC and the Republic of Niger entered into a Transportation Convention in relation to the planned crude oil export Niger-Benin Export Pipeline. The Niger-Benin Export Pipeline is expected to run for c. 2,000 km from the ARB in Niger to Port Seme on the Atlantic coast in Benin, and is expected to be complete by the end of 2021. Under the terms of Savannah's PSCs, the Petroleum Code of Niger and its Implementing Decree, Savannah is entitled to access such third-party infrastructure. Importantly, the Niger-Benin Export Pipeline provides Savannah with a significant additional potential route to market, alongside the existing SORAZ refinery.

Figure 10, Map of Savannah's R3 East discovery hub



Source: Savannah, 2020

Contingent Resources

Each of the five wells drilled by Savannah in 2018 can be classified as 'Discoveries' under the Petroleum Resource Management System (PRMS) 2018 definitions, and for which Contingent Resource volumes can be estimated, as determined by CGG in the Niger CPR. These amount to over 33 MMstb net attributable to Savannah in the 2C, mid case.

Figure 11, Contingent Resource estimates

	Gross on Licence			*Net Attributable*			*Chance of Development*	*Operator*
Discovery	*1C*	*2C*	*3C*	*1C*	*2C*	*3C*		
Amdigh	7.2	18.4	83.9	6.8	17.5	79.7	High	Savannah
Eridal	4.3	6.2	8.5	4.0	5.9	8.1	High	Savannah
Bushiya	3.3	6.2	12.9	3.2	5.9	12.3	High	Savannah
Kunama	1.8	4.2	9.3	1.8	4.0	8.8	High	Savannah
Total MMstb	16.7	35.0	114.6	15.8	33.3	105.1		
Zomo	0.0	0.2	0.0		0.2		Medium	Savannah

Note: Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

Source: Adapted from the Niger CPR

Four of these discoveries are assessed by CGG as having a high probability of commercial development, allowing relatively near-term future conversion of these volumes to Reserves under PRMS guidelines. Evaluation of the Zomo discovery is preliminary, pending further seismic evaluation, and the indicative resources shown are excluded from the total.

Prospective Resources

CGG recognises a total of eleven exploration Prospects and Leads, for which Prospective Resource estimations have been made (Figures 37 and 38 of Part 5 of this document). Five of these are located on the R3/R4 PSC, with an aggregate gross Best Estimate resource potential of 90 MMstb, and assessed Chance of Success of 25 per cent. to 75 per cent. Three of these are deep exploration targets in the Cretaceous Yogou formation below the shallower discoveries at Bushiya, Amdigh and Eridal. Two further undrilled leads are identified on the western edge of the PSC, with prospectivity in the Sokor as well as the deeper Yogou formation.

A further six undrilled exploration prospects and leads have been assessed by CGG in the R1/2/4 PSC Area, within the R1/R2 PSC Area to the north west of the R3/R4 PSC. These all have exploration potential throughout the section and have a larger aggregate gross resource potential of 270 MMstb (Best Estimate). Two of these features, Kunkuru and Damissa, are covered by 3D seismic and are thought to have a high chance of exploration Success (>75 per cent.). The other four features are also large (30 – 80 MMstb) but are currently regarded as high risk (most <25 per cent. chance of exploration success).

14. Summary Financial Information of the Target Companies

The summary financial information presented below has been extracted without material adjustment from the historical financial information of the Target Companies as set out in Part 6B of this document. This summary financial information has been derived from the audited financial statements of Accugas, SUGL, Exoro and Universal for the year ended 31 December 2018 and the unaudited interim financial statements of Accugas, SUGL, Exoro and Universal for the six month period ended 30 June 2019, as adjusted by Savannah for the purposes of presenting such information in accordance with Savannah's own accounting policies.

	FY 2018 *$000*	*H1 2019* *$000*
Income Statement Selected Line Items		
Revenue	93,572	70,271
Operating Profit	145,016	14,178
Profit/(Loss) Before Tax	45,255	(32,191)
Profit After Tax	42,144	3,376
Balance Sheet Selected Line Items		
Total Assets	1,154,252	1,201,650
Total Liabilities	1,555,354	1,599,353
Net Liabilities	(401,102)	(397,703)
Net Debt	(804,800)	(814,570)
Cash Flow Statement Selected Line Items		
Cash Flow from operating activities	73,758	23,271
Cash used in financing activities	(76,149)	(23,790)
(Decrease)/increase in cash and cash equivalents	(7,264)	1,702

15. Summary 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 year ended 31 December 2018 and the unaudited interim financial information for the six month period ended 30 June 2019.

Figure 12, Summary Financial Information of the Existing Group

	FY 2018 $000	*H1 2019 $000*
Income Statement Selected Line Items		
Revenue	–	–
Operating Loss	(28,069)	(10,931)
Loss Before Tax	(24,608)	(3,000)
Loss After Tax	(24,613)	(3,003)
Balance Sheet Selected Line Items		
Total Assets	266,234	288,036
Total Liabilities	(38,429)	(41,273)
Net Assets	227,805	246,763
Net Debt	(13,121)	(11,770)
Cash Flow Statement Selected Line Items		
Cash Flow from operating activities	(32,446)	(10,027)
Cash used in investing activities	(77,385)	(9,982)
Cash provided by financing activities	96,677	20,863
(Decrease)/increase in cash and cash equivalents	(13,154)	854

An unaudited pro forma statement of net assets of Enlarged Group is set out in Part 7 of this document.

16. Current trading of the Enlarged Group

The operating and financial performance of the Nigerian Assets continued to improve during the course of 2019 and into the first quarter of this year. 2019's performance, as compared to 2018, is summarised in the table below:

	Year ended 31 December 2019	*Year ended 31 December 2018*
Gas sales – MMscfpd	93.9	64.2
Average selling price – US$/Mcf	3.57	3.40
Oil production (gross) – bopd	2,519	2,393
Total cash collections – US$ million	168.8	128.7
EBITDAX – US$ million	89.5	6.9

Note: the financial information included above for the year ended 31 December 2019 is unaudited and may be subject to adjustment before the results for the year ended 31 December 2019 are published

In 2019, year-on-year gas sales increased by 46 per cent. to an average of 93.9 MMscfpd, principally as a result of increased volumes being supplied to Calabar whose offtake increased by approximately 130 per cent. compared to 2018. The average realised price was five per cent. higher in 2019 at US$3.57 per Mcf largely as a result of the price indexation that is embedded into the GSAs. Oil production was 5 per cent. higher in 2019 at 2,519 bopd, principally from the Stubb Creek Field which achieved average daily production of 2,393 bopd as a result of increased uptime compared to 2018. The unaudited EBITDAX for the Nigerian Assets for 2019 was US$89.5 million, compared to US$6.9 million in 2018. Total cash collections from gas sales and oil production amounted to US$169 million in 2019 which was 31 per cent. higher than in 2018.

Q1 2020 trading

Gas sales in the first quarter of 2020 increased by 20 per cent. compared to the average for 2019 to 113.1 MMscfpd, despite Ibom Power being offline for much of the period. Calabar's offtake in this period was a further 40 per cent. higher than its average offtake for 2019 and a peak daily production rate of

164 MMscfpd was achieved in February 2020. Oil production was marginally lower in Q1 2020 compared to last year at 2,387 bopd as a result of the Stubb Creek Field being shut in for 10 days due to required maintenance at the FUN Manifold.

Since the Transaction was completed in November 2019, total cash collections from the Nigerian Assets have amounted to US$96 million, the Enlarged Group has paid down US$40 million of the restructured debt taken on as part of the Acquisition and the Capital Restructuring and, as referred to in paragraph 7 above, the Group entered into its first new GSA for over five years.

Your attention is drawn to the Risk Factors in Part 3 of this document and, in particular, that relating to the evolving situation with the COVID-19 pandemic. This has already had a significant impact on global oil prices and could have further impact on the Group's business and financial performance if, for one reason or another, the Group is unable to supply gas to any of its customers or its customers have to curtail or cease production and, therefore, take delivery of lower gas volumes.

17. Future strategy of the Enlarged Group

Savannah seeks to enhance and ultimately realise sustainable value for stakeholders through the successful delivery of material projects across the energy asset life cycle. The Enlarged Group has a valuable and stable asset base which provides a strong platform for future growth, and the Directors believe that energy companies can create substantial value by acquiring, either organically or inorganically, oil and gas reserves and resources at a significant discount to the net present value per share of the cash flows that they are capable of subsequently realising from those reserves and resources.

In the near-term, significant benefits to the Enlarged Group are expected to be realised through the cash flows which are expected to be generated by the Uquo Field, Stubb Creek Field and Accugas as well as through the development of the Company's Niger R3 East EPS. Accugas' immediate focus is on the addition of new customers, including power stations, and higher margin industrial customers. Existing Accugas infrastructure is largely ex-capex and with significant spare capacity, and therefore there is strong operational gearing associated with the signature of new gas contracts, which are long-term in nature.

Outside of "on asset" or "near asset" growth opportunities in Niger and Nigeria, the Company reviews potential acquisitions and strategic transactions on an ongoing basis. In order for the Company to progress with a growth opportunity, it assesses the potential opportunity to deliver material NAV accretion, asset diversification and medium-term cost of capital reduction. Opportunities should also be cash flow generative, or close to delivering cash flow generation, represent controlling interests in assets (or have a competent, credible operator) and be located in an emerging market jurisdiction with high-quality subsurface characteristics.

The Company also keeps under review the best avenue for developing its Nigerien Assets and Nigerian Assets, which may, in due course, result in the Company seeking independent finance for each business.

Savannah's business model is underpinned by the Company's entrepreneurial and proactive culture. Savannah focuses on generating long-term value over short-term results and aims to move quickly to take advantage of opportunities that arise and to react promptly to changes in the business environment.

18. Directors and Senior Managers

Directors

Stephen ("Steve") Ian Jenkins, aged 61 – *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 Rothwell O'Brien, aged 63 – *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 39 – *Chief Executive Officer*

Andrew was the principal founder of Savannah, becoming a Director of the Company in July 2014. 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 43 – *Chief Financial Officer and Company Secretary*

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. Isatou played a key role in the negotiation, implementation and completion of the Seven Energy Transaction

David Clarkson, aged 68 – *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 was accountable for embedding rigour and discipline in BP Upstream's major project investment decisions and had responsibility for a functional business unit that managed a c. US$20 billion annualised capex budget and employed c. 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. Between June 2018 and December 2019, David acted as the Company's Chief Operating Officer, and during that time led Savannah's operations as the Company carried out its five well Niger drilling campaign as well as the integration of the Nigerian Assets. David is a Chartered Engineer and a Fellow of the Institute of Mechanical Engineers.

Marco ("Mark") Iannotti, aged 51 – *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 75 – *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).

Michael Jon Wachtel, aged 54 – *Non-Executive Director*

Michael serves as Head of Energy and Natural Resources, Corporate, 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 leading independent oil companies. As a former member of Clyde & Co LLP's UK management Board, he was responsible, alongside the other members of the firm's boards, for the running of a business with over 45 international offices and a global turnover in excess of £500 million. Prior to entering law, Michael gained a master's degree in mechanical engineering and worked as an oil and gas field engineer in Africa, including West Africa, 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.

Antoine Richard, aged 52 – *Chief Operating Officer*

Antoine has over 20 years' experience working for both major (Total) and independent (Perenco) oil & gas companies worldwide, including over 10 years' experience in West Africa. He has a strong operational background, with a focus on production optimisation, onshore facilities design and operation, management of drilling campaigns and seismic acquisition programs. His previous positions within Perenco included Global HSE Manager and General Manager roles for Congo, Egypt and Venezuela. Antoine acted as Savannah's VP Operations from 2016 until 2018, over which time he delivered the Company's 806 km^2 R3 East 3D seismic acquisition campaign with no lost-time incidents and within budgeted time, and also left Savannah well-placed to deliver its successful five well R3 East exploration campaign which achieved a 100 per cent. success rate. As Chief Operating Officer, Antoine is based in Lagos and has responsibility for Group-wide operations.

Yacine Wafy, aged 36 – *Managing Director, 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.

Chris Thomas, aged 58 – *Head of Strategy*

Chris joined Seven Energy in 2009 and was Chief Financial Officer from 2017, playing a leading role in the capital restructuring of Seven Energy and the transaction with Savannah. Chris has over 30 years' experience in corporate finance generally, with over 25 of those spent 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. He was also the founder and Executive Chairman of Renova Energy plc, a US biofuel company that was listed on AIM. Chris is a member of the Institute of Chartered Accountants in England and Wales.

Jessica Ross, aged 34 – *VP Corporate Affairs*

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. Jessica played a key role in the implementation and completion of the Seven Energy Transaction.

19. Health, safety, security and environment

Savannah is committed to managing its operations in a safe, secure, reliable and environmentally sustainable manner, and to act in a responsible manner towards its stakeholders, and considers that a high standard of health and safety performance and environmental protection is critical to the ongoing success of the

Company and the Enlarged Group. The Enlarged Group has Health and Safety, Environmental and Corporate Social Responsibility policies in place, and reports its performance to the Board through the Health, Safety, Security and Environmental ("**HSSE**") Committee as well as through its Annual Report and other corporate updates. The Company expects its employees, visitors and contractors and partners to comply with these policies and to enforce similarly high HSSE standards.

The Company also has a robust HSSE management system in place which aligns with international management system standards and local legislation, takes a proactive approach to the identification and management of HSSE risks and is underpinned by on-site leadership and through a leading indicator monitoring approach to building safe working practices.

20. 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 since the Company was incorporated as a result of the prevailing commodity price environment (which has seen oil prices fall from c. US$100/bbl in August 2014 at the time of the Company's IPO to c. US$23/bbl currently (Brent Crude)).

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.

21. Corporate governance

The Board of Directors of Savannah recognises its responsibility for the proper management of the Company and the importance of sound corporate governance, proportionate to the size and nature of the Company and the interests of its shareholders. As an AIM-quoted Company, the Board is committed to maintaining high standards of corporate governance and, following the changes to AIM Rule 26 in September 2018, it adopted the 2018 Quoted Companies Alliance Corporate Governance Code for Small and Mid-Size Quoted Companies (the "**QCA Code**" or the "**Code**") as the basis of the Group's governance framework. A statement of the Company's compliance with the QCA Code is set out on its website: www.savannah-energy.com/AIM.

Set out below is a summary of the Company's current corporate governance structure and practices.

The Board

The Board is collectively responsible to the shareholders of Savannah for the effective oversight and long-term success of the Company. The Board has overall responsibility for strategy, purpose, business model, performance, capital structure, approval of key contracts and major capital investment plans, the framework for risk management and internal controls and governance matters, as well as engagement with shareholders and other key stakeholders. The Directors remain focused on understanding the needs of shareholders and other stakeholders and considering how the Board's decisions impact them in the longer term. 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 from time to time as required by the business of the Company. The Board addresses several recurring items at each Board meeting, including strategic, operational and financial performance updates and Board Committee reports following any Committee meetings. In addition, technical developments, Health, Safety, Security and Environment issues, strategic projects, investor relations and corporate communications, and governance matters are regularly discussed and in-depth reports on particular aspects of the business are presented. The Directors also have an ongoing dialogue between Board meetings on a variety of issues.

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, in accordance with the principles of the QCA Code, is responsible for leading the Board and ensuring that it remains effective in fulfilling its role. Mr. Jenkins was considered to meet independence criteria set out in the UK Corporate Governance Code on appointment. The Chairman is responsible for setting the Board's agenda, ensuring that there is appropriate focus on strategic issues and the monitoring of performance. The Chairman promotes a culture of openness and debate within the Board, where Directors can discuss and challenge the actions of the executive management, as well as the views of all Directors, promoting good decision-making and ultimately supporting the Company's long-term success. The Committee Chairmen 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. The Company's performance and development planning, led by Mr Knott as CEO, is considered by the Directors in the context of the Company's overall strategy and goals, within the Company's risk and governance frameworks and taking into account their impact on stakeholders in the longer term.

Composition, qualification and independence of the Board

The Board comprises of eight Directors: Non-Executive Chairman, the Non-Executive Vice Chairman, four Non-Executive Directors and two Executive Directors (the CEO and CFO). Steve Jenkins, Sir Stephen O'Brien, Mark Iannotti, David Jamison and Michael Wachtel are all deemed to be independent within the meaning of the QCA Code. Please refer to paragraph 18 of this Part 1 for more information in relation to each Director.

Mr Clarkson served on the Board as an independent Non-Executive Director between December 2017 and June 2018, when he was appointed as Chief Operating Officer in on an interim basis. He has since stepped down from his role as the COO and resumed his role as a Non-Executive Director.

The Directors' biographies illustrate the wide range and high calibre of skills and experience that the Directors bring to the Board to help deliver the strategy of the Company for the benefit of the shareholders over the medium to long term. An in-depth review of the skills, capabilities, experience and personal qualities of the Directors was completed in early 2019, which demonstrated that the Board as a whole does have the necessary mix of experience, skills, personal qualities and capabilities. These include appropriate industry, strategic, operational, risk management, financial, legal, geopolitical 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 senior management and other Directors. As the size and complexity of the business increases, the composition of the Board will continue to be reviewed, taking into account the Company's circumstances, strategy and goals.

The Board has considered and reviewed the independence and effectiveness of each Non-Executive Director, taking into account any factors that might affect, or could appear to affect, a Director's judgement and therefore their independence. The Board considers that the performance-related shares and options awarded to certain 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, character or judgement.

Board evaluation and appointments to the Board

In line with the recommendations of the QCA Code, the Board undertakes an annual evaluation of its performance, that of the Chairman, the Board's Committees and individual Directors. To date, the evaluation has been conducted based on a detailed questionnaire, which looks to assess the effectiveness of the Board, the Directors and the Chairman, as well as the Committees' activities, processes and policies. The results of the most recently conducted evaluation indicated that the Board and its Committees received strong feedback for their performance, including their effectiveness, balance of skills, experience, knowledge and independence. Actions arising from recommendations to further improve the effectiveness of the Board are being implemented and the Board intends to continue to undertake annual appraisals and report on the progress made against the actions identified. The Chairman also continues 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 Board places value on attracting Directors with diverse outlooks and experience. On the Remuneration and Nomination Committee's recommendation, the Board makes appointments to achieve the balance of skills, experience and knowledge needed, but does so solely on merit. Any Director appointed by the Board must offer himself or herself for election at the first AGM following appointment and for re-election at intervals of three years thereafter.

Directors' Training

The Chairman, with the support of the Company's Nominated Adviser, 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 comprehensive Board induction programme is tailored to the individual needs and requirements of the Directors, and includes, 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.

The Directors also receive regular updates on market and regulatory developments, including legal and governance matters, and are provided with training as required to ensure that their skills and experience are kept up to date.

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 since January 2018, 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 supported by the Company Secretary and a team at Link Company Matters in relation to governance, statutory and compliance matters, as well as with organising Board and Committee meetings and circulating any requisite papers, aiming for information to be provided to the Board members in a timely manner.

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. Mr. Iannotti is considered by the Board to have recent and relevant financial experience and the Committee as a whole has competence relevant to the oil and gas industry. 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 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:

- reviewing the integrity and content of the financial statements, including reviewing and reporting to the Board on significant financial reporting issues and judgements;
- reviewing adequacy and effectiveness of the Company's internal controls and risk management policies and systems;

- reviewing and monitoring compliance policies and systems, including prevention and detection of fraud and tax evasion;
- monitoring compliance with applicable regulations;
- reviewing and approval of the annual audit plan and reviewing the audit findings with the external auditor; and
- assessing external auditor objectivity and independence and reviewing the performance and remuneration of the external auditor.

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. 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.

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 Chairmen 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 its terms of reference, the Committee's key responsibilities are:

- determining and reviewing the terms and conditions of service and termination of employment of Executive Directors and senior employees;
- determining and reviewing the remuneration of Executive Directors and senior employees;
- reviewing and approval of grants of shares or options, from time to time;
- reviewing and recommending to the Board appointments and re-elections of Directors to the Board; and
- reviewing the composition of the Board, the membership of the Committees and making recommendations to the Board on any proposed changes.

The Remuneration and Nomination Committee acknowledges the importance and the value of succession planning in order to ensure that the Company has the benefit of an appropriate mix of skills and experience as the Board and senior management team evolve. The Board will continue to undertake an annual evaluation of its performance, that of its Committees and the individual Directors, to ensure that the Board continues to function effectively. The discussions around the Company's strategy, objectives and forward plans, as well as an assessment of the Directors' current mix of skills, experiences and personal qualities, all inform the succession plans for the Board. Succession planning for the key members of the senior management team is also underway.

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.

The Role of the Health, Safety, Security and Environment Committee

The Health, Safety, Security and Environment Committee is chaired by David Clarkson and its other members are Steve Jenkins and Sir Stephen O'Brien.

The role of the Committee is to oversee the 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. Under its terms of reference, the Committee's key responsibilities are:

- ensuring 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;
- promoting appropriate behaviours, decisions and culture;
- communicating the Board's commitment to these matters to the Group's staff, contractors and other stakeholders;
- overseeing compliance with, and effectiveness of, the HSSE framework;
- receiving reports on all serious accidents and incidents within the Group, including corresponding actions taken by management; and
- overseeing the quality and integrity of any reporting to external stakeholders regarding health, safety, security and environmental matters.

The Committee meets three times a year, or more frequently if required. Its terms of reference are available on the Company's website.

The Role of the Compliance Committee

The Compliance Committee is chaired by Michael Wachtel and its other members are David Clarkson, David Jamison and Mark Iannotti.

The Committee's role is to support the Board in carrying out its duty to promote and oversee compliance with all legal and regulatory obligations including the UK Bribery Act 2010 and the US Foreign Corrupt Practices Act. Under its terms of reference, the Committee's key responsibilities are:

- reviewing and monitoring compliance controls, policies and systems to identify, assess, manage and report on compliance matters, including:
  - the prevention of bribery, corruption, money laundering and countering of terrorist financing;
  - gifts and hospitality, per diem payments, business relationships, including dealings with public officials, agents, intermediaries, consultants, contractors and advisers;
  - mergers, acquisitions and major new projects;
  - whistleblowing arrangements and reports;
  - conflicts of interest; and
  - legal and regulatory compliance risks.
- assessing the adequacy and effectiveness of the compliance framework; and
- communicating the Board's commitment to compliance to the Group's staff, contractors and other stakeholders.

The Committee regularly reviews the current compliance policies, procedures and systems to ensure that these continue to be proportionate to the scale and range of the Company's operations.

The Committee meets four times a year. Its terms of reference are 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 EU Market Abuse Regulations ("**MAR**") and of the AIM Rules. All Directors have received training on MAR, 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.

Whistleblowing and anti-bribery and anti-corruption controls

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 or 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. During 2018, the Compliance Committee considered the existing arrangements, including the whistleblowing channels that enabled the employees to raise concerns, and consequently, in early 2019, the Committee oversaw the introduction of a whistleblowing hotline. Concerns 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 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 Group operates, as well as providing guidance on how to recognise and deal with bribery and corruption issues and their potential consequences.

The Group's policy is circulated to all Group employees and is provided to any new joiners and 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.

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 have been designed to assist the Board in making robust decisions to create and protect shareholder value by creating sustainable growth over the medium to long term.

These internal controls will be re-assessed on an ongoing basis, 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 Chief Financial Officer, 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 and this is being reviewed in the light of the Acquisition and the integration of the Nigerian Assets.

Conflicts of Interest

Directors have a statutory duty to avoid situations in which they have, or may have, interests that conflict with those of the Company, unless that conflict is first authorised by the Board. This includes potential conflicts that may arise when a Director takes up a position with another company. The Company's Articles allow the Board to authorise any potential or actual conflict of interest that a Director may have. A process has been implemented to identify and deal with any such conflicts.

Culture and Stakeholders

Savannah is committed to promoting a healthy and responsible corporate culture and, accordingly, has put into place a number of policies and mechanisms to ensure that ethical values and behaviours are recognised and respected. The Board will continue to review its objectives as well as the strategy and business model of the Enlarged Group, and how to best monitor and promote the desired culture and behaviours going forward.

Savannah is committed to seeking to create, add and realise value not just for its financial stakeholders but for its host communities, its partners and its employees. Savannah believes that maintaining effective stakeholder engagement programmes is essential and this includes a number of initiatives to support the local communities in which the Company operates.

22. 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 in 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 40,354,453 Ordinary Shares, representing 4.05 per cent. of the Existing Ordinary Shares.

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 10 of this document.

23. Lock-in arrangements

Each of the Directors and Senior Managers who hold Ordinary Shares have undertaken to the Company and Strand Hanson that they will not dispose of any interest in the Ordinary Shares held by them for a period of 12 months from the date of Re-Admission. In total, 33,120,171 Ordinary Shares representing 3.32 per cent. of the Existing Share Capital at Re-Admission are subject to this prohibition. Further details of the lock-in arrangements are set out in paragraph 9.2.6 of Part 10 of this document.

24. Shareholder returns policy

Given the global uncertainty created by the COVID-19 crisis and the resultant challenges and the opportunities the Company expects to face and be exposed to over the course of the next year, the Board does not expect to pay a dividend in respect of 2020. The Board remains open however to the possibility, in certain circumstances, of implementing a share buyback programme in 2020. Further updates on shareholder returns will be provided in due course.

25. UK Taxation

Information regarding UK taxation is set out in paragraph 17 of Part 10 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.

26. 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**"), and more recently put in place the Additional Share Scheme (as further described below), further details on which are disclosed in paragraph 4 of Part 10 of this document.

As disclosed in the Dec 2017 Admission Document, in the view of the Remuneration and Nomination Committee, the vesting and hurdle conditions of the Existing Plans were too stretching to serve as a realistic incentive. Accordingly, and as disclosed in the Dec 2017 Admission Document, the Company had intended to reduce: (i) the Hurdle Price (as defined in paragraph 4.2 of Part 10 of this document) under the Long Term Incentive Plan from £1.68 to £0.42; and (ii) the vesting condition under the Supplementary Plan to a target share price of £0.42 per Ordinary Share. Rather than effect these changes at this current time, it is anticipated that the Company's Remuneration and Nomination Committee will undertake a review of the Existing Plans to ensure that the vesting and hurdle conditions continue to serve as a realistic incentive in the current market. Such conditions will be determined in consultation with Savannah's Nominated Adviser and it is acknowledged that, in certain circumstances, a fair and reasonable opinion pursuant to AIM Rule 13 of the AIM Rules may be required to be given on the amendments.

Additional Share Scheme

The Board believes that the success of the Company will depend to a significant degree on the future performance of the Company's senior management team, in particular its CEO, Mr Knott, and therefore that it is important to ensure that the members of the senior management team are well motivated and identify closely with the success of the Company. To incentivise certain existing and future senior management, the Remuneration and Nomination Committee in 2017 recommended to offer them the option of participating in a new share incentive scheme (the "**Additional Share Scheme**").

The Company's Remuneration and Nomination Committee engaged New Bridge Street, part of AON plc, to advise on potential structures for the Additional Share Scheme.

The Additional Share Scheme was established on 15 June 2018. Awards under the Additional Share Scheme will take the form of nil-cost options over a total of 42,624,837 existing Ordinary Shares currently held in the EBT. Vesting of the awards to participants will be linked to total shareholder return (based on share price performance and dividends), measured against the 30-day volume weighted average price ("**VWAP**") of the Company's shares during a five-year period.

The awards will vest on a straight-line basis should the VWAP at any point during the five-year period exceed a price range as determined by the Board, with 100 per cent. vesting on the VWAP reaching the top end of the price range. Participants who receive shares pursuant to the awards will be subject to a three-month lock-in period during which they will not be permitted to deal in such shares, subject to certain limited exceptions.

All awards under the Additional Share Scheme will be subject to the participant's continued employment or other engagement with the Company, and malus provisions. To further align the interests of the Company's senior management team and those of shareholders, the Company's share dealing code will be amended such that employees who are participants in the Additional Share Scheme who are awarded shares will only be permitted to dispose of such shares if, post-disposal, their residual shareholding will be valued at an amount equal to at least 200% of their base salary (based on the VWAP on the date of such disposal).

As was disclosed in the Dec 2017 Admission Document, the Company sought shareholder approval for the proposed award of options over 21,312,418 existing ordinary shares (held in the employee benefit trust) under the terms of the Additional Share Scheme to Mr Knott. The award was approved by Savannah shareholders at its AGM held on 3 May 2018. However, as at the date of this document, no awards under the Additional Share Scheme have been made.

In order to facilitate the Additional Share Scheme, the Company established the EBT. The EBT subscribed for 42,624,837 new Ordinary Shares (the "**EBT Shares**") at a subscription price per share equal to the nominal value of the shares (£0.001 per share) simultaneously with the allotment and issue in February 2018 of the new Ordinary Shares associated with the Company's placing at that time. SP1L, a wholly owned subsidiary of the Company agreed, to 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.

27. Admission, settlement and CREST

Application has been made for the Existing Share Capital to be re-admitted to trading on AIM and it is expected that Re-Admission will become effective and dealings in the Existing Share Capital will commence at 8.00 a.m. on 18 May 2020.

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 Re-Admission, settlement of transactions in the Ordinary Shares may continue to 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.

28. Risk factors and Additional Information

Your attention is drawn to the additional information set out in Parts 2 to 11 (inclusive) of, and the appendices to, 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 8 and 9 of this document, has been reviewed and approved by CGG. CGG has 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.

PART 2

TRANSACTION OVERVIEW

1. Changes to the Transaction

Since the Company first announced the proposed transaction with the Seven Group and some of the financial creditors of the Seven Group in 2017, the terms of the Transaction and the interests being acquired by the Company as described in the Dec 2017 Admission Document were amended.

The key differences between the Acquisition as it was initially described in the Dec 2017 Admission Document and as it was subsequently amended (as described by the Company's RNSs of 20 September 2018, 21 December 2018 and 1 October 2019) are summarised in Figure 13 below and described in further detail in Part 1 of this document.

Figure 13 – Summary of Interests Acquired by the Company Following Transaction Amendments

	December 2017	*Upon Transaction Completion*	*Comment*
Uquo Gas & Condensate	87.7%	80.0%[1]	Amended per FOL Transaction and AIIM Transaction
Uquo Oil	85.0%	–	Amended per FOL Transaction
Universal (Stubb Creek)	62.5%	100.0%[2]	Acquisition of Universal minority shareholders
Accugas Midstream Business	20.0%	80.0%[3]	Amended per FOL Transaction and AIIM Transaction

Notes

1. The Uquo interests reflects the Company's net economic interest in the Uquo Field after taking into account the 20 per cent. equity interest held by AIIM, via African Upstream Holdings Mauritius, in Uquo HoldCo, the holding company of SUGL;
2. This represents the Company's economic interest in Universal, which holds a 51 per cent. operating interest in the Stubb Creek Field; and
3. This represents the Company's shareholding interest in Accugas HoldCo, which is the holding company for the Accugas Midstream Business.

2. Transaction Summary

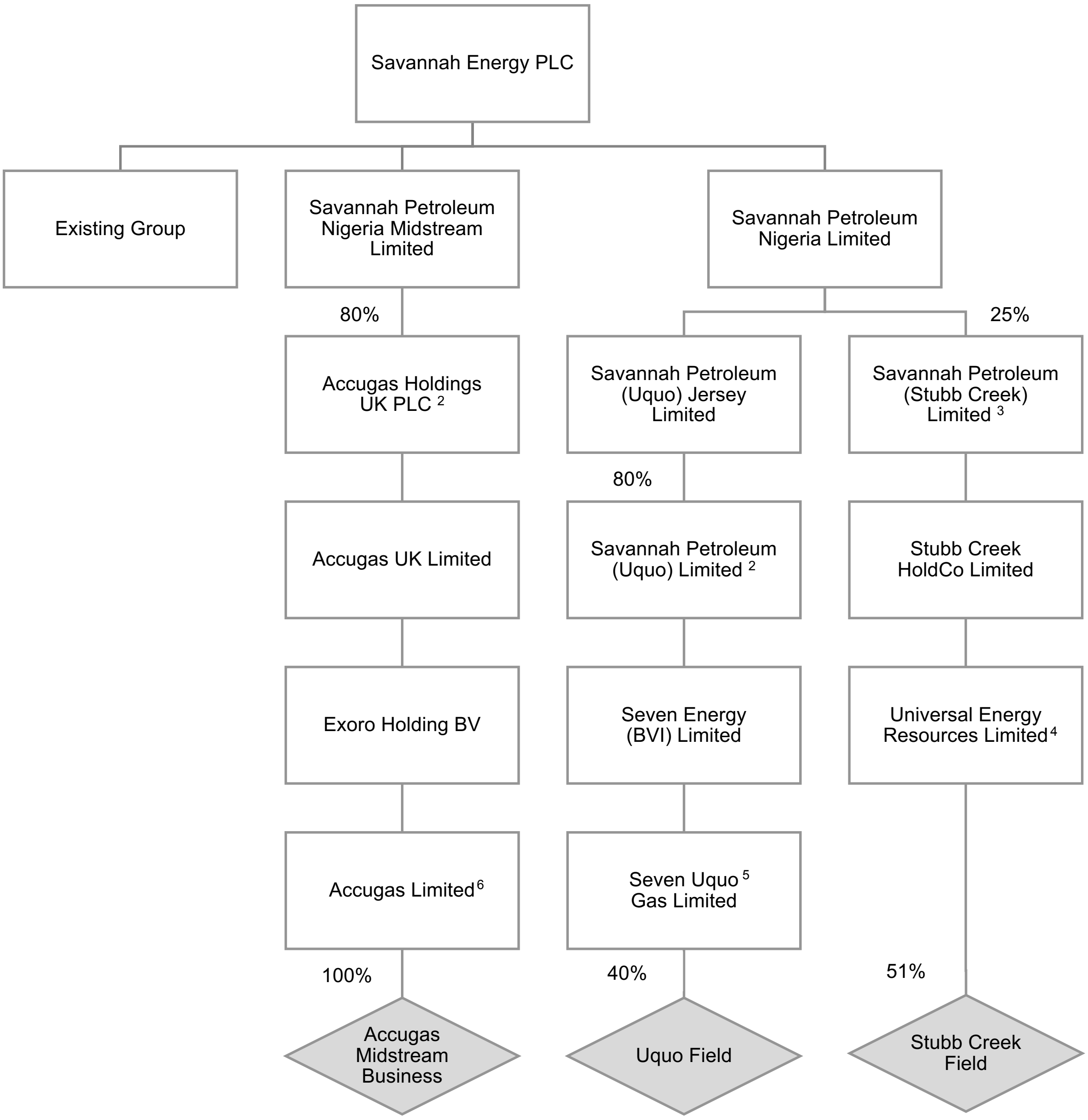
2.1. Following the completion of the Transaction, the FOL Transaction and the AIIM Transaction, the Company owns:

2.1.1. an 80 per cent. interest in Uquo HoldCo and its wholly owned subsidiary, SUGL, which in turn holds a 100 per cent. economic interest in the Uquo Gas Project on the Uquo Field located in South East Nigeria. Under the terms of the FOL Transaction, which was completed in December 2019, SUGL assumed responsibility for all operations of the Uquo Gas Project at the Uquo Field and took over operations of the CPF;

2.1.2. a 51 per cent. operating interest in the Stubb Creek Field located in South East Nigeria (through 100 per cent. economic ownership of Universal); and

2.1.3. an 80 per cent. interest in the Accugas Midstream Business, comprising the 200 MMscfpd Uquo gas processing facility, a c. 260 km gas pipeline network and long-term gas sales agreements with downstream customers.

2.2. A simplified structure chart of the Enlarged Group is shown below:



Notes

1. All shareholdings are 100 per cent. unless otherwise stated.
2. 80 per cent. owned, the remaining 20 per cent. is owned indirectly by AIIM.
3. 25 per cent. owned, the remaining 75 per cent. is owned by STC Joint Venture Limited, a company incorporated in Nigeria, with Savannah Petroleum (Stubb Creek) Limited retaining an effective 51 per cent. economic interest in the Stubb Creek Field;
4. One share in Universal is held by Savannah Petroleum Nigeria Limited;
5. One share in Seven Uquo Gas Limited is held by Savannah Petroleum Nigeria Limited;
6. One share in Accugas Limited is held by Accugas Holdings UK PLC; and

It is intended that subsidiaries which reference the Company's prior name, Savannah Petroleum, will be changed to match the new name, Savannah Energy, in due course.

2.3. Pursuant to the Transaction, the indebtedness in the Seven Group was restructured as follows:

Figure 14 – Capital Restructuring (figures are approximate)

Facility	*Principal amount outstanding immediately prior to Completion*[1] *US$m*	*Reinstated Debt in the Enlarged Group upon Completion*			
		Accugas Holdco US$m	*Acugas US$m*	*SUGL US$m*	*Total US$m*
SSNs [2]	318.2	20.0	–	–	20.0
10.50 per cent. Notes	106.5	–	–	105.0	105.0
First Bilateral Facility	24.1	20.0	–	–	20.0
Second Bilateral Facility	25.0	–	–	–	–
Accugas Term Facility [3]	370.8	–	382.1	–	382.1
SUGL Working Capital Facility	13.3	–	–	13.3	13.3
Promissory Note	11.5	11.5	–	–	11.5
DSA Facility [3]	11.3	–	–	–	–
Total	880.7	51.5	382.1	118.3	551.9

Notes

Since Completion, US$40 million of the reinstated debt has been paid down by Savannah

1. Amount excludes any accrued (or default) interest (save that the amounts shown in respect of the 10.50 per cent. Notes and the SSNs include a coupon that was capitalised as part of a restructuring that took place in 2016). With the exception of any outstanding interest on the Accugas Term Facility or the SUGL Working Capital Facility, none of the accrued and unpaid interest on the Seven Group indebtedness was reinstated in the Enlarged Group as part of the Capital Restructuring.
2. In February 2018, the Company acquired $305.6 million of the SSNs by way of the Exchange Offer.
3. The DSA Facility was aggregated into the Accugas Term Facility as part of the Capital Restructuring.

2.4. As a result of the amendments made to the Transaction structure since the Dec 2017 Admission Document, as more fully described in Part 1 of this document, the proforma indebtedness of the Enlarged Group as a result of Completion has increased from approximately US$85.0 million to US$551.9 million, principally due to the Company acquiring an 80 per cent. interest in the Accugas Midstream Business.

2.5. As summarised in Figure 14 above:

2.5.1. As part of the Capital Restructuring at Completion, holders of the SSNs were entitled to subscribe, at the time of the Exchange Offer with respect to the SSNs, for new Ordinary Shares in the Company up to a value of US$26.7 million (the "**SSN Shares**"). Holders of the SSNs who elected to subscribe for the SSN Shares were also entitled to a *pro rata* share of the US$20 million senior secured notes with a maturity date of 15 November 2025, the Accugas Holdco Senior Secured Notes, that were issued by Accugas Holdco to an SSN holder and certain underwriters as part of the completion mechanics of the Transaction. The Accugas Holdco Senior Secured Notes are secured by way of a first ranking charge *pari passu* with the Promissory Note, against the shares of Accugas Holdco, Accugas Midco and Exoro as well as the assets of Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) against the shares or assets of Accugas. Under the terms of the Transaction, US$152 million of the SSNs were redeemed and a residual amount of approximately US$166.2 million SSNs (excluding accrued but unpaid interest) were left outstanding in the Seven Group as at Completion.

2.5.2. The majority of the outstanding amount under the 10.50 per cent. Notes was re-instated with a new issuance by SUGL, the SUGL Notes, of US$105 million senior secured notes due 2026, with a residual amount of approximately US$1.5 million (excluding accrued but unpaid interest) remaining at SEFL as at Completion. The SUGL Notes are secured, by way of a first ranking charge *pari passu* with the SUGL Working Capital Facility, against the shares of SPNL's subsidiaries as well as the assets of SPNL and its subsidiaries, including the interests the Enlarged Group owns in the Uquo Field and the Stubb Creek Field.

2.5.3. The First Bilateral Facility made available to SEFL and SEL was restructured such that US$20 million was reinstated at Accugas Holdco, the Reinstated First Bilateral Facility, with a residual amount of approximately US$4.1 million (excluding accrued interest) remaining at SEFL and SEL as at Completion. The Reinstated First Bilateral Facility, which has a maturity date of 14 November 2025, is secured against the shares of Accugas Holdco, Accugas Midco and Exoro as well as the assets of Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) against the shares or assets of Accugas. Shortly following Completion, the Reinstated First Bilateral Facility was purchased by the Company as lender.

2.5.4. The Second Bilateral Facility was reduced by US$12.7 million in exchange for the issue of US$9.2 million worth of new Savannah shares and the payment of US$3.5 million in cash. The residual amount of approximately US$12.3 million principal plus accrued interest remained outstanding at SEL.

2.5.5. The Accugas Term Facility was amended and restated as a US$382.1 million term facility with a maturity date of 31 December 2025, the Amended and Restated Term Facility, and is secured against the assets and the shares of Accugas. The amounts outstanding under the DSA Facility were rolled into the Amended and Restated Term Facility on Completion.

2.5.6. The SUGL Working Capital Facility was amended and restated as an NGN 4.8 billion (approximately US$13.3 million) term facility with a maturity date of 31 December 2026. The amended and restated SUGL Working Capital Facility is secured, by way of a first ranking charge pari passu with the SUGL Notes, against the shares of SPNL's subsidiaries as well as the assets of SPNL and its subsidiaries, including the interests the Enlarged Group owns in the Uquo Field and the Stubb Creek Field.

2.5.7. The Promissory Note was amended and novated to Accugas Holdco as counterparty. The amended and restated Promissory Note is a US$11.5 million promissory note with a maturity date of 31 December 2025 and is secured, by way of a first ranking charge pari passu with the Accugas Holdco Senior Secured Notes, against the shares of Accugas Holdco, Accugas Midco and Exoro as well as the assets of Accugas Holdco and Accugas Midco, but not (for the avoidance of doubt) against the shares or assets of Accugas. The amended and restated Promissory Note is additionally secured, by way of a second ranking charge to the SUGL Notes and the SUGL Working Capital Facility, against the shares of SPNL's subsidiaries as well as the assets of SPNL and its subsidiaries, including the interests the Enlarged Group owns in the Uquo Field and the Stubb Creek Field.

2.6. Further descriptions of the key terms of the reinstated debt are set out in paragraph 1 of Part 11 of this document.

3. History of the Transaction

3.1. In November 2017, the Company, the Seven Group and certain of the Seven Group's key creditors/creditor groups 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. In February 2019, the same parties entered into the Implementation Agreement, which documented the legal terms and steps pursuant to which the Transaction was to be implemented by the respective parties. Prior to Completion, long-form documentation in relation to the restructuring of the Seven Group's debt was agreed with key stakeholders, including several stakeholders that were not party to the Implementation Agreement.

3.2. Under the terms of the Lock-up Agreement and for the purposes of facilitating the Acquisition, the Company effected the Exchange Offer with respect to the SSNs. Under the terms of the Exchange Offer which closed in February 2018, the Company acquired US$305.6 million of the SSNs, representing 96.0 per cent. of the outstanding SSNs, for a cash consideration of approximately US$40.9 million and the issue of 224,021,689 new Savannah shares at the December 2017 placing price.

3.3. Completion was conditional on certain consents being obtained to various aspects of the Transaction, including the consent of the Minister of Petroleum Resources of the Federal Government of Nigeria. All necessary consents were obtained.

3.4. In October 2019, the Company announced that long-form documentation was signed by Frontier, SUGL and Accugas in relation to the FOL Transaction and the restructuring of economic ownership interests at the Uquo Field and the operatorship of the Uquo CPF. The FOL Transaction was conditional upon completion of the Transaction and closed on 31 December 2019. The terms of the FOL Transaction provided that, whilst Frontier's and SUGL's participating interests in the Uquo Field remains at 60 per cent. and 40 per cent. respectively, SUGL is granted economic ownership and control of 100 per cent. of the gas project at the Uquo Field (including associated condensate production), Accugas Limited is granted operatorship of the Uquo CPF and Frontier is granted economic ownership and control of 100 per cent. of the oil project at the Uquo Field, all with an economic effective date of 31 August 2018. Under the terms of the FOL Transaction, SUGL made an advance payment of cash calls of US$20 million to Frontier on the completion of the FOL Transaction. A further US$14.13 million of advance cash calls is payable in Naira across three yearly instalments, with the first instalment of US$5 million due twelve months following the completion of the Transaction, the second instalment of US$5 million due twenty-four months following completion of the Transaction and the final instalment of US$4.13 million due thirty-six months following completion of the Transaction. The final instalment due to Frontier will be subject to a deduction of c. NGN 1.2 billion in respect of gas sales proceeds received by Frontier between 31 August 2018 and the date of completion of the FOL Transaction (net of royalties paid by Frontier in respect of the corresponding volumes of gas).

3.5. Shortly prior to Completion, an internal reorganisation of intercompany balances and shareholdings was effected within the Seven Group in accordance with the Implementation Agreement in order to facilitate the Transaction.

3.6. At a hearing of the English High Court on 13 November 2019, English administrators were appointed to SEIL, immediately subsequent to which Mauritian administrators were also appointed to SEIL. On 14 November 2019, the Seven Group (with SEIL acting by its English and Mauritian administrators) effected the transfer of the Nigerian Assets to group companies controlled by the Company pursuant to a number of sale and purchase agreements. Immediately following the Acquisition, AIIM acquired a 20 per cent. interest in each of the holding companies of SUGL and Accugas Limited, Uquo HoldCo and Accugas HoldCo respectively, for an aggregate cash consideration of US$54 million, including a contribution towards the costs of the Transaction, payable to the Company. Following this step, certain long-form documentation with respect to the Capital Restructuring became effective in accordance with the agreed steps as set out in the Implementation Agreement and, on 15 November 2019, the Company announced that the Transaction had completed.

3.7. The total approximate consideration payable by the Group in accordance with the terms of the Acquisition, consisted of:

3.7.1. US$0.065 million in cash;

3.7.2. US$3.5 million in promissory notes;

3.7.3. US$136.5 million in assumed debt;

3.7.4. new Ordinary Shares with a value of US$9.2 million; and

3.7.5. US$152 million in transferred SSNs.

116,638,985 new Ordinary Shares were issued in aggregate by the Company as part of the Completion mechanics, including new Ordinary Shares with a value of US$26.7 million issued to a holder of the SSNs and certain underwriters as part of the Capital Restructuring (as referred to in paragraph 2.5.1 above).

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 an authorised professional adviser 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.

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 operating 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. Coronavirus
2. Exploration, development, production and business risks associated with the Nigerian Assets
3. Exploration, appraisal, development and production risks associated with the Niger Assets
4. General risks associated with the operations and business of the Enlarged Group
5. Risks relating to operating in Nigeria
6. Risks relating to operating in Niger
7. Risks relating to the Ordinary Shares

1. Coronavirus

The ongoing COVID-19 (coronavirus) pandemic could have a material adverse effect on the Enlarged Group's results of operations and financial condition

The recent outbreak of COVID-19 (commonly referred to as coronavirus) which first occurred in Wuhan City, China and has subsequently spread to many countries throughout the world, including the UK, the USA, mainland Europe, Africa and the Asia-Pacific region, has begun to negatively impact economic conditions globally and there are concerns for a prolonged tightening of global financial conditions. The COVID-19 outbreak could result in protracted volatility in international markets and/or result in a global recession as a consequence of disruptions to travel and retail segments, tourism and manufacturing supply chains. In particular, in March 2020, the COVID-19 outbreak caused stock markets worldwide to lose significant value and impacted economic activity worldwide.

Although the Company is taking measures to mitigate the broader public health risks associated with COVID-19 to its business and employees, including through self-isolation of employees where possible in line with the recommendations of relevant health authorities, the full extent of the COVID-19 outbreak and the adverse impact this may have on the Enlarged Group's workforce and key suppliers and its impact on the global economy, Nigerian and Nigerien economies and the oil and gas industries is unknown. In addition, as a result of the COVID-19 outbreak, there may be short-term impacts on the Enlarged Group's supply chain and planned work programmes in Nigeria and Niger. Similarly, government-imposed travel restrictions may impair the ability of certain of the Enlarged Group's employees to conduct physical inspections of existing operations and visit in country offices.

Furthermore, there can be no assurances that contract counterparties will not seek to renegotiate contractual terms or seek to claim force majeure to excuse performance of their contractual obligations to the extent that they are affected by the COVID-19 outbreak.

As referred to in more detail in paragraph 2.20 of this Part 3, the Enlarged Group has been the subject of spurious claims and litigation and, in this current uncertain economic environment, the Directors expect that it will continue to be subject to such claims and, in particular, that the incidence of such spurious claims, including claims for force majeure, is likely to increase with many businesses and contractual counterparties suffering temporary hardship and disruption as a result of COVID-19 pandemic and seeking any means to reduce their exposure to such disruption.

Given the fast-moving nature of the outbreak and increasing government restrictions, there can be no assurances that there will not be a material adverse effect on the Enlarged Group's results of operations and financial condition.

It is further noted that as a result of the outbreak, it has not been possible for the Company's Nigerian counsel to undertake, immediately prior to publication of this document, the necessary in person searches that are required in Nigeria to confirm the good standing of the Company's licences and subsidiaries. The relevant searches were last completed in March 2020 by the Company's Nigerian counsel confirming the good standing of the local subsidiaries and pipeline licences as at that date. The Stubb Creek licence was confirmed to be in good standing in a letter from the DPR in February 2020 and the Uquo Field licence good standing confirmation is subject to the payment of a fee, the question of which is currently under negotiation between Savannah and the DPR (a matter which is further described in Risk Factor 5.13).

Whilst the Company has no reason to believe that the good standing of its Nigerian licences and subsidiaries will have changed between the date of the searches and the date of this document, it cannot rely on up to date searches to evidence this fact, and in the unlikely event that a successful challenge had been lodged in this interim period, as to the good standing nature of the Company's assets in Nigeria, it may result in the Enlarged Group being required to halt development or production or operations or, ultimately, in the loss of such assets.

2. Exploration, appraisal development, production and business risks associated with the Nigerian Assets

2.1 *The Enlarged Group's future cashflows depend on certain key end users and such key end users may fail to fulfil their contractual obligations to the Enlarged Group or the Enlarged Group could fail to obtain replacement customers*

The Enlarged Group has entered into three long-term take-or-pay gas sales agreements with Ibom Power, NDPHC and CGCL and Unicem. The Enlarged Group expects these three agreements will contribute a very significant portion of its future revenue. The inability of any of the key contractual counterparties to meet their obligations to the Enlarged Group or failure to make timely payments may affect the Enlarged Group's financial results, cashflows and ability to service its debt. Payments for the supply of gas to the Calabar power plant are supported by the World Bank Partial Risk Guarantee.

In addition, payments for the supply of gas to the Calabar power plant and to the Ibom Power station have previously been supported by a payment assurance facility from the Federal Government of Nigeria through the Ministry of Finance and the Central Bank of Nigeria.

There is no assurance that such programme will remain in place or continue to be funded. Despite this programme being in place, Accugas Limited has historically experienced payment delays in respect of the supply of gas to Calabar NIPP and Ibom Power station. As at the date of this document, US$65 million is outstanding under the Calabar GSA and the Company is working with NDPHC to settle this amount in a timely fashion without resorting to claiming under the World Bank Partial Risk Guarantee. NDPHC is the primary obligor under the Calabar GSA and it is the Directors current intention only to invoke the Partial Risk Guarantee once all other commercial avenues have been exhausted with NDPHC.

In the event that Ibom Power, NDPHC and CGCL, or Unicem do not fulfil their obligations to the Enlarged Group under the respective gas sales agreements, or in the event that any of these entities become insolvent or subject to liquidation, the Enlarged Group may seek to enforce the terms of the agreements, including the NDPHC letter of credit and the World Bank Partial Risk Guarantee provided in respect of the Calabar NIPP gas sales agreement. There can be no assurance as to how long an enforcement action may take, or whether at the time of such enforcement, the relevant guarantor will be able to meet its obligations. In addition, in the event that any of the Enlarged Group's customers change ownership, the contractual obligations of the other counterparties may transfer to the new owner and may expose the Enlarged Group to different payment and credit risks.

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. This may impact Accugas Limited's ability to pay its creditors.

In addition, the Upstream GSA under which SUGL sells gas from the Uquo Field to Accugas Limited is structured on a 'pay-when-paid' basis. Therefore, if Accugas Limited's customers fail to pay or are late in paying Accugas Limited, SUGL will not receive any cashflow. This may in turn impact SUGL's ability to pay its creditors. 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 cashflows, results of operations, financial condition and prospects.

2.2 *A significant proportion of the Enlarged Group's cashflow is supported by the World Bank Partial Risk Guarantee*

A significant proportion of the Enlarged Group's cashflow, arising under the Calabar GSA, is supported by the World Bank Partial Risk Guarantee, provided by the International Development Agency to Accugas Limited, backed by a letter of credit (as further described in Part 11 of this document). Under the terms of the Partial Risk Guarantee and associated documents, the Federal Government of Nigeria has provided an indemnity to the International Development Agency in the event that Accugas Limited were to call on the letter of credit. Under the terms of the Partial Risk Guarantee agreement, there is a risk that the International Development Agency could, after giving notice, suspend this guarantee and, ultimately, terminate the guarantee if Accugas Limited does not comply with its terms. The Directors believe that the Enlarged Group has the policies and procedures in place to ensure compliance with the relevant representations, covenants and obligations, which largely relate to environmental and social practices and anti-bribery and corruption standards (as more fully described in paragraph 4.2.5 of Part 11 of this document).

2.3. ***The Enlarged Group is not yet in receipt of the licence to operate the Uquo CPF or the Stubb Creek EPF***

As at the date of this document, Accugas Limited does not yet have a licence to operate ("LTO") the Uquo CPF in accordance with the applicable Nigerian petroleum related regulations. Operating a plant without an LTO may attract criminal penalties under Nigerian law. It is not unusual in Nigeria for it to take a considerable period of time for an operator to receive its LTO.

Frontier, as the then operator of the Uquo CPF, was issued with a LTO in respect of the Uquo CPF for the year 2019 on 15 October 2019, which expired on 31 December 2019. Such delay in the issue of the annual LTO was not uncommon and Frontier was able to operate the Uquo CPF without the LTO without interruption or sanction from the relevant authorities. On 25 October 2019, Frontier applied for a renewal of the LTO (prior to Completion and change of operatorship) for 2020 and this has not yet been issued. The DPR has been notified of the transfer of operatorship of the Uquo CPF and that the LTO should be renewed in the name of Accugas Limited.

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 could interrupt production from the Stubb Creek Field.

The Group is in discussions with the relevant authorities on obtaining the licences.

2.4. ***A significant proportion of the Enlarged Group's revenue is derived from the sale of gas to the Nigerian power sector***

The Nigerian power sector suffers from numerous problems, such as limited access to infrastructure, low connection rates, inadequate power generation capacity, lack of capital for investment, insufficient transmission and distribution facilities, high technical losses and vandalism. These problems contributed to Nigeria ranking as the 185th most difficult country in which to obtain access to electricity, according to the World Bank.

Nigeria initiated the privatisation of its electricity sector in 2013 with the sale of successor companies unbundled from the main power utility company, Power Holding Company of Nigeria Plc, to multiple consortia of private investors. This transition may further disrupt generation of an adequate electricity supply. There can be no assurance that this privatisation will continue or will not be reversed.

2.5 ***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.

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

The Enlarged Group's upstream 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 these 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 "Risks related to operating in Nigeria".

2.7 ***Operational impediments or damage to, or the shut-down of, processing and transport infrastructure may hinder the Enlarged Group's access to oil and gas markets or delay or cease production***

The Enlarged Group is reliant on the Uquo CPF and the Stubb Creek EPF to process crude oil and natural gas. Any sudden loss of, or significant 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 uses 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 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 the Enlarged Group will be able to find a replacement or arrange necessary repairs on a timely or cost-effective basis.

The Enlarged Group may also be required to shut in wells for regulatory reasons or due to a lack of demand or inadequacy or unavailability of a pipeline, gathering system or processing capacity. If a shut-in were to occur, the Enlarged Group would be unable to realise revenue from those wells until suitable arrangements were made to transport and market that production.

Any significant delay, interruption or stoppage to the Enlarged Group's oil and gas operations could damage the Enlarged Group's relationships with one or more of its key customers, harm its reputation and cause the Enlarged Group to be liable for breach of contract for a failure to meet its contractual obligations.

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

2.8 ***The Enlarged Group is, or could potentially in the future be, reliant on third party owned or operated infrastructure for the transport of its oil and natural gas liquids 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 and natural gas liquids (or condensate) sold through QIT for export. The Enlarged Group's oil and condensate volumes are stabilised through the FUN Manifold, which is jointly owned by the Uquo JV, the Stubb Creek JV and a third-party JV.

The inadequacy or unavailability of such oil and condensate pipeline capacity and infrastructure, and/or the necessary licences to operate and export, 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.

In the past, Accugas Limited has also used third party owned and operated gas transportation pipelines to access other customers and gas markets in the region on an interim basis and this may happen again in the future in order for Accugas Limited to access new markets.

2.9 ***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". Further, in 2014 the DPR issued guidelines for obtaining ministerial consent to the assignment of interests in Oil and Gas assets in Nigeria. The guidelines provide that the total interest assignable to a foreign entity in a marginal oil field in Nigeria shall not exceed 49 per cent. of the total overall interest in the asset.

Although the Directors believe that the current ownership structures of both the Stubb Creek Field and the Uquo Field satisfy the "substantially Nigerian" requirement, to the extent the 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.

2.10 ***The Enlarged Group has not maintained decommissioning arrangements and/or 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, and in line with a number of other operators of marginal fields, these provisions have not been strictly enforced and such decommissioning arrangements/security arrangements have not been put in place. If a notice of breach were 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 accounting provision has been made for these costs, no escrow account or reserve has been maintained.

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

Both the Enlarged Group and its partners are obliged to comply with the requirements of the applicable contracts, 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 participants were to fail to cooperate, it may delay or disrupt existing or future projects. 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 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. 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 counterparty 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. Furthermore, contract counterparties may seek to renegotiate contractual terms in the event of changes in their business or operating environment, economic hardship or financial distress. In such circumstances, the Enlarged Group may have to resort to legal process to enforce its contractual rights and such processes can be time consuming and costly and could result in an adverse outcome for the Enlarged Group.

Unicem is, for example, currently seeking to renegotiate its payment obligations to Accugas Limited under the Unicem GSA. Accugas Limited believes that Unicem has no legal or contractual basis for doing so and has clearly indicated to Unicem that it intends to fully enforce its contractual rights.

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.

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.

2.12 ***Deferred payments to Frontier***

As part of the FOL Transaction and pursuant to the terms of the agreement with Frontier, SUGL is required to pay Frontier deferred cash calls in three annual instalments which in aggregate shall equal the Naira equivalent of US$14.13 million. The three yearly instalments payable to Frontier are subject to a deduction of c. NGN 1.2 billion in respect of gas sales proceeds received by Frontier between 31 August 2018 and the date of completion of the FOL Transaction (net of royalties paid by Frontier in respect of the corresponding volumes of gas). Failure by SUGL to pay Frontier any instalment will give rise to the right for Frontier to require SUGL to transfer a portion of its economic interest in the Uquo Gas Project as a default remedy.

2.13 ***Perfection of legal title to CPF Land***

As part of the FOL Transaction, title to the land on which the CPF is located is being transferred from Frontier to Accugas Limited. Until perfection of the transfer of title to such land has been completed at the relevant land registry, Accugas Limited's title to the land is currently only an equitable interest and the deed of sublease of the CPF land to Accugas Limited dated 4 June 2015 between Frontier and Accugas Limited shall remain in effect. The Company's legal counsel is currently undertaking the process of perfecting title to such land, but the process has stalled due to the coronavirus pandemic as the relevant government offices have had to close.

2.14 ***The Enlarged Group's leverage and debt service obligations could adversely affect its business and prevent it from fulfilling its obligations under the debt facilities***

As of 30 June 2019, after giving pro forma effect to the Acquisition and the Capital Restructuring, the Enlarged Group would have had total borrowings of US$553 million of debt outstanding.

This amount of leveraged debt could have important consequences for the Enlarged Group's business including, but not limited to:

- making it more difficult for it to satisfy its obligations with respect to the various financing arrangements;
- increasing the Enlarged Group's vulnerability to, and reducing its flexibility to respond to, general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of the Enlarged Group's cash flow from operations to the payment of principal of, and interest on, indebtedness, thereby reducing the availability of such cash flow for other uses;
- limiting the Enlarged Group's ability to obtain additional financing to fund working capital, capital investments, acquisitions, other debt service requirements, business ventures or other general corporate purposes;

- limiting its flexibility in planning for, or reacting to, changes in its business and the competitive environment and the industry in which the Enlarged Group does business;
- placing the Enlarged Group at a competitive disadvantage compared to competitors that have lower leverage or greater financial resources;
- negatively impacting credit terms with its creditors; and
- limiting the Enlarged Group's ability to borrow additional funds and subjecting it to financial and other restrictive covenants.

These consequences could have a material adverse effect on the Enlarged Group's business, prospects, financial condition and results of operations and on its ability to satisfy its obligations under the various financing agreements.

Furthermore, the Enlarged Group requires a significant amount of cash to service its debt and to sustain its operations, and its ability to generate sufficient cash depends on many factors beyond its control. The Enlarged Group's ability to make payments on, or repay or refinance, its debt, and to fund working capital and capital investments, will depend on its future operating performance and ability to generate sufficient cashflow. This depends on the success of the Enlarged Group's business strategy and on general economic, financial, competitive, market, legislative, regulatory, technical and other factors discussed in these "Risk factors", many of which are beyond the control of the Company.

A breach of any covenant or restriction or a failure to make scheduled payments of principal or interest on any of the Enlarged Group's indebtedness could result in a default that would permit the lender or noteholder to declare all amounts borrowed to be due and payable, together with accrued and unpaid interest. In addition, since certain of the financing arrangements are secured by various security agreements, such as pledges over shares of certain subsidiaries (and, in particular, Accugas Limited, SUGL and Universal), any enforcement action taken by a lender could include the sale by such lenders of the property securing such debt if the Enlarged Group is unable to pay the outstanding debt on demand. Accordingly, payment default or covenant breaches and the subsequent exercise by the relevant lenders of their rights under the various financing agreements could have a material adverse effect on the Enlarged Group's business, results of operations, cash flows, financial condition and prospects.

2.15 ***Labour relations***

Certain employees of the Enlarged Group are members of trade union bodies. Any labour disputes, unrest or strike activity 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 its ongoing operations and the Enlarged Group's ability to explore for, produce and market oil and gas production or cause cost increases or additional work rules imposed by agreements with trade unions. All of these factors could adversely affect the Enlarged Group's business, results of operations, cash flows, financial condition and prospects.

2.16 ***Expiry of contracts***

The Enlarged Group is party to various contracts and arrangements that will expire at points in time in the future in accordance with their terms. There can no assurance that such contracts will, if required, be renewed either on the same terms or otherwise.

2.17 ***Revenue recognition under take-or-pay gas sales agreements***

The Enlarged Group may be in position to deliver contracted gas volumes when its customers are not ready or able to receive those volumes. The take-or-pay provisions in the gas sales agreements bind the purchaser to pay for certain quantities of gas even when undelivered, from the date on which the gas is available for delivery. However, title to gas sold only passes on the date of delivery and, as the risk of ownership only transfers upon delivery, revenue from the sale of the gas is recognised only on a delivered basis. In circumstances which the Enlarged Group receives payments pursuant to take-or-pay provisions and gas is not delivered to the contractual counterparties, the Enlarged Group is unable to recognise this income as revenue for accounting purposes and instead accrues it as deferred revenue.

2.18 ***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***

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. 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 GSA for ultimate downstream sale to Ibom Power, the Calabar NIPP and the Unicem cement plant, represent all of the discovered gas reserves and resources forecast to be 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.

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

The price of oil and condensate 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.

2.20 ***The Enlarged Group may 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, putting forward allegations which are unfounded due to the limited nature of the country's libel laws.

The Seven Group was 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 Savannah's 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 10 of this document have been commenced against certain members of the Enlarged Group. The Directors, having taken legal advice, believe such claims are spurious and/or lack merit and are vigorously defending them. 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 Savannah did not acquire as part of the Acquisition. The claims pursuant to such proceedings amount to an aggregate of over NGN 29 billion. Although these proceedings have not been brought in relation to companies within the Enlarged Group as part of the Transaction, there is a residual risk that claimants may attempt to extend their claims to the Enlarged Group.

2.21 ***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 Nigerian Assets. There have, in the past, been allegations and investigations into companies in the Seven Group which are not included in the Nigerian Assets and did not relate to the Nigerian 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 Target Companies 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 Nigerian 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 Nigerian Assets, whether or not such allegations or investigations were founded in fact.

3. Exploration, appraisal, development, production and business risks associated with the Nigerien assets

3.1 ***The Enlarged Group is dependent on Council of Ministers approval for the award of the R1/R2/R4 PSC***

As is referred to earlier in this document, the initial term of the Exclusive Exploration Authorisation on the R1/R2 PSC has expired, however, the Company has agreed with the Ministry of Energy and Petroleum that the R4 area will be combined with the R1/R2 PSC Area into a new PSC to be issued under the Petroleum Code 2017, thus retaining the full acreage position previously covered by the R1/R2 PSC and the R3/R4 PSC.

The new PSC covering the R1, R2 and R4 areas is subject to approval by the Council of Ministers and will be formally awarded to Savannah on payment of the signature bonus. Whilst the Directors expect that Council of Ministers approval will be forthcoming shortly after publication of this document, there is no guarantee this will be the case, or approval will be received at all.

Until such approval is received, and the signature bonus paid by Savannah within the stipulated timeframe, Savannah is limited in its ability to carry out activities on the R1/R2/R4 PSC area.

3.2 ***Title matters and payment obligations***

Although the Savannah PSCs and various international treaties to which Savannah Niger is a signatory offer a strong protection to the Enlarged Group, an unforeseen defect in title, changes in law (or interpretations thereof), regulatory consents or political events may arise or occur to defeat or impair the claim of the Enlarged Group to some or all of the rights in properties which it currently owns or is interested or may acquire which could result in a material adverse effect on the Enlarged Group, including a reduction in any revenues generated.

3.3 ***Early stage of operations***

The Enlarged Group's operations in Niger are at an early stage of development and future success will depend, *inter alia*, on the Directors' ability successfully to manage and exploit the current asset portfolio and to take advantage of further opportunities which may arise. 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, develop its Nigerien assets.

An investment in the Company is subject to certain risks related to the nature of the Enlarged Group's business in the acquisition, appraisal, exploitation, development and production of oil and natural gas assets and their early stage of development. The Enlarged Group has a limited operating history in

Niger and no history of positive earnings, and there can be no assurance that the Enlarged Group's business will be successful or profitable.

Further, the Enlarged Group has no assets in Niger producing positive cash flow and its ultimate success will depend on, *inter alia*, the Enlarged Group's future success in discovering oil and/or natural gas, the Directors' ability to implement their strategy, generate cash flow from economically viable projects and access appropriate sources of future funding, including, but not limited to, equity markets, bank debt and proceeds from potential asset sales. 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's business plan to exploit and commercialise its Nigerien assets will require significant capital expenditure for the identification, acquisition, appraisal, exploration, development and production of oil and gas resources and/or reserves in the future. The Enlarged Group's inability to access sufficient capital for its operations may have a material adverse effect on its business, financial condition, results of operations and prospects.

3.4 ***Farm down of the Enlarged Group's assets in Niger***

In due course the Enlarged Group may, subject to receipt of any necessary consents, farm down part of its licence interests to third parties, some of which may act as operator. Operating agreements with third party operators typically provide for a right of consultation or consent in relation to significant matters and generally impose standards and requirements in relation to the operator's activities. However, in the event that the Enlarged Group does not act as operator in respect of certain of its licence interests, the Enlarged Group will generally have limited control over the day-to-day management or operations of those assets and will therefore be dependent upon the third-party operator. A third-party operator's mismanagement of an asset may result in significant delays or materially increased costs to the Enlarged Group. The Enlarged Group's return on assets operated by others will therefore depend upon a number of factors that may be outside the Enlarged Group's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Generally, a failure by any licence partner (whether the operator or otherwise) to fulfil its financial obligations may increase the Enlarged Group's exposure related to the licence in question. Any significant increase in costs as a consequence of joint and several liabilities may materially adversely affect the financial condition of the Enlarged Group.

There can be no certainty that a farm out transaction will be successfully concluded due to, without limitation, an inability to secure suitable terms, failure of a potential farminee to achieve appropriate management or regulatory approvals, or a change in the Enlarged Group's strategy.

3.5 ***Foreign subsidiaries***

The Enlarged Group conducts most of its operations in Niger through its subsidiary, Savannah Niger, which is located outside of the United Kingdom. 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 the jurisdiction in which it or any other Group company operates, and the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated.

3.6 ***Exchange controls in Niger***

Savannah Niger is subject to the special foreign exchange regime provided for under the Savannah PSCs as well as the common law foreign exchange regime for issues with respect to which the Savannah PSCs do not provide for a preferential treatment.

In accordance with the combined provisions of the West African Economic and Monetary Union Foreign Exchange Regulation and of the Savannah PSCs, there are no restrictions on transfers of funds into Niger though Savannah Niger must send a quarterly report to the Nigerien Government with all information concerning the movement of capital and payments made by it that are required for declaration purposes.

Any resident company intending to transfer foreign currency out of the country must provide supporting documentation. Residents are required to transfer any income in foreign currency via an approved intermediary. In this case as well, Savannah Niger must, each quarter, send to the Nigerien Government all information concerning the movement of capital and payments out of Niger effected by it.

Notwithstanding the stabilisation of the foreign exchange regime granted to Savannah Niger in accordance with the terms of the Savannah PSCs, if restrictions on exchange controls are changed in a manner detrimental to the Enlarged Group, its business, prospects, results of operations or financial conditions could be materially adversely affected, as would its ability to pay dividends on the Ordinary Shares, should any be declared.

3.7 ***Production operations in Niger may produce unforeseen issues and drilling activities may not be successful***

Any production operations at the Savannah PSCs would involve risks common to the industry, including blowouts, oil spills, explosions, fires, equipment damage or failure, natural disasters, geological uncertainties, unusual or unexpected rock formations and abnormal geological pressures. In the event that any of these occur, environmental damage, injury to persons and loss of life, failure to produce oil or gas in commercial quantities or an inability to fully produce discovered reserves could result. Drilling activities may be unsuccessful and the actual costs incurred in drilling, operating wells and completing well workovers may exceed budget. There may be a requirement to curtail, delay or cancel any drilling operations because of a variety of factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. The occurrence of any of these events could have a material adverse effect on the Enlarged Group's business, prospects, financial condition and operations.

3.8 ***Oil exploration and production in Niger and the sale of such production depends on adequate infrastructure***

Reliable roads, bridges, power sources and water supplies are important determinants which affect capital and operating costs. Generally speaking, Niger suffers from underdeveloped infrastructure, communication problems (particularly internet access), energy shortages and high energy costs.

3.9 ***Interruptions in availability of exploration, production or supply infrastructure in Niger***

The Enlarged Group may suffer, indirectly, from delays or interruptions due to lack of availability of drilling rigs or construction of infrastructure, including pipelines, storage tanks and other facilities, which may adversely impact the operations and could lead to fines, penalties, criminal sanctions against the Enlarged Group and/or its officers or its current or future licences or interests being terminated. Despite assurances given by the Nigerien Government in the Savannah PSCs, there is the risk of delays in obtaining licences, permissions and approvals required by the Enlarged Group or its partners in the pursuance of its business objectives could likewise have a material adverse impact on the Enlarged Group's business and the results of its operations.

3.10 ***Failure to meet contractual work commitments may lead to penalties***

The Enlarged Group is subject to contractual work commitments, including those specified within the Savannah PSCs, which include minimum work programmes to be fulfilled within certain time restraints. Specifically, these commitments may cover certain depths of wells to be drilled, seismic surveys to be performed and other data acquisition. Failure to comply with such obligations, whether inadvertent or otherwise, may lead to fines, penalties, restrictions and withdrawal of licences with consequent material adverse effects.

4. General risks associated with the operations and business of the Enlarged Group

4.1 ***Risks relating to the Enlarged Group's activities in the oil and gas industry***

There are numerous factors which may affect the success of the Enlarged Group's business which are beyond its control including local, national and international economic, legal and political conditions. The Enlarged Group's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. The operations of the Enlarged Group in West Africa may expose it to potential civil unrest and political or currency risks.

4.2 ***Oil prices***

The marketability and price of oil and natural gas that may directly or indirectly be acquired or discovered by the Enlarged Group will be affected by numerous factors beyond the control of the Enlarged Group, but which include: global and regional supply and demand, expectations regarding future supply and demand, for oil and gas; global and regional economic conditions; political, economic and military developments in oil and gas producing regions; prices and availability of alternative sources of energy; geopolitical uncertainty; speculative activities and trends in the financial community; and the ability and desire of members of OPEC, and other oil producing nations, to set and maintain specified levels of production and prices. Low oil prices will reduce the projected economic value of the Enlarged Group's assets, make it harder for the Company to attract partners and/or capital and reduce the cashflows of the Enlarged Group's assets once developed.

4.3 ***Governmental relations may change and retention of key business relationships***

To protect the Enlarged Group's licences and permits to operate and its ability to secure new resources it is important that the Enlarged Group should maintain strong positive relationships with the governments of, and communities in, the countries where its business is conducted. Failure - real or perceived – to maintain these relationships, or any of the risk factors described in this announcement materialising, could harm the Enlarged Group's reputation, which could, in turn, impact the Enlarged Group's licences, financing and access to new opportunities. Furthermore, the Enlarged Group's principal gas sales agreement is with NDPHC and CGCL, both Federal Government controlled entities, and there is a risk that government departments or agencies may seek to persuade Accugas not to enforce its contractual rights.

Although the Company believes it has good relations with both the Nigerian and Nigerien Governments, there can be no assurance that the actions of present or future governments in Nigeria and Niger and governments of other countries in which the Enlarged Group may operate, directly or indirectly, in the future, will not materially adversely affect the business or financial condition of the Enlarged Group.

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

4.4 ***The Enlarged Group operates in a capital intensive industry and expanding its gas transportation and processing infrastructure and increasing reserves and production will require additional funding to meet both expected and unanticipated costs, which the Enlarged Group may not be able to raise***

The Enlarged Group's business requires significant capital expenditures for appraisal, development, maintenance, production, processing infrastructure and transportation and, in the future, the Enlarged Group may seek additional financing to fund its future exploration, development, acquisition and/or construction plans beyond its current committed and planned expenditures.

There can be no assurance that the Enlarged Group will be able to generate or raise sufficient funds to meet our 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; commodity prices for oil and gas; investor confidence in the oil and gas industry in Nigeria, Niger and in the Enlarged Group; business performance; regulatory developments, including tax and securities laws that are conducive to raising capital; and credit available from banks and other lenders.

Furthermore, the ability of many companies to arrange financing and the cost of financing are subject to events affecting the global financial markets. Also, the cost of and terms and conditions on which future funding or financing may be made available may not be acceptable or funding or financing may not be available at all and any additional debt financing may involve financing costs including prepayment fees or restrictive covenants and ratios that could limit or affect our operational flexibility.

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

If the Enlarged Group's revenue or reserves decline, it may be unable to raise additional funds (or any external debt or equity financing may not be available on acceptable terms) or have the capital necessary (either from internal sources or through external debt or equity financing) to undertake or complete future drilling and development programs or acquisitions.

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

4.5 ***Exploration, development and production risks***

There can be no guarantee that hydrocarbons will be discovered in commercial quantities, or that those potentially discovered will be developed into profitable production. Developing a hydrocarbon production field requires significant investment, generally over several years, to build the requisite operating facilities, drilling of production wells along with implementation of advanced technologies for the extraction and exploitation of hydrocarbons with complex properties. Making these investments and implementing these technologies, normally under difficult conditions, can result in uncertainties about the amount of investment necessary, operating costs and additional expenses incurred as compared with the initial budget, thereby negatively affecting the business, prospects, financial condition and results of operations of the Enlarged Group. In addition, hydrocarbon deposits assessed by the Enlarged Group may not ultimately contain economically recoverable volumes of resources and even if they do, delays in the construction and commissioning of production projects or other technical difficulties may result in any projected target dates for production being delayed or further capital expenditure being required. There is also the risk that the Enlarged Group may not be awarded exclusive exploitation rights in respect of reserves which are ultimately identified.

The operations and planned drilling activities of the Enlarged Group and its partners may be disrupted, curtailed, delayed or cancelled by a variety of risks and hazards which are beyond the control of the Enlarged Group, including unusual or unexpected geological formations, formation pressures, geotechnical and seismic factors, environmental hazards such as accidental spills or leakage of petroleum liquids, gas leaks, ruptures or discharge of toxic gases, industrial accidents, occupational and health hazards, technical failures, mechanical difficulties, equipment shortages, labour disputes, fires, power outages, compliance with governmental requirements and extended interruptions due to inclement or hazardous weather and ocean conditions, explosions, blow-outs, pipe failure and other acts of God.

Any one of these risks and hazards could result in work stoppages, damage to, or destruction of, the Enlarged Group's or its partners' facilities, personal injury or loss of life, severe damage to or destruction of property, environmental damage or pollution, clean-up responsibilities, regulatory investigation and penalties, business interruption, monetary losses and possible legal liability which could have a material adverse impact on the business, operations and financial performance of the Enlarged Group. Although precautions to minimise risk are taken, even a combination of careful evaluation, experience and knowledge may not eliminate all of the hazards and risks. In addition, not all of these risks are insurable.

4.6 ***Hydrocarbon resource and reserve estimates***

No assurance can be given that hydrocarbon resources and reserves reported by the Enlarged Group previously, now or in the future are or will be present as estimated, will be recovered at the rates estimated or that they can be brought into profitable production. Hydrocarbon resource and reserve estimates may require revisions (either up or down) based on historical production, technical data and in light of the prevailing market price of oil and gas. Hydrocarbon resource and reserve estimates are highly subjective, and there is a risk that there are discrepancies between those estimates and the resources and reserves which are ultimately identified, both in terms of volume of resources and reserves identified, and in terms of the potential for recovery of such resources to be economically recoverable. A decline in the market price for oil and gas could render reserves uneconomic to recover and may ultimately result in a reclassification of reserves as resources.

4.7 ***Capital and operating expenditure estimates may not be accurate***

Estimated capital and operating expenditure requirements are estimates based on anticipated costs and are made on certain assumptions. Given the inherent uncertainties as to Savannah's future work programmes and associated capital expenditures, the uncertain time frame during which the capital expenditures will be made and sources of finance will be made available to the Enlarged Group, and the general correlation between oil and gas capital expenditures and global commodity markets there is a risk that currently assessed capital and operating expenditure costs may prove to be inaccurate. In addition, given the pragmatic approach of Savannah's Board and executive management team, nearer term capital and operating expenditure may be subject to change if Savannah's Board and management believe such a change is in the best interests of the Enlarged Group.

Should the Enlarged Group's capital and operating expenditure requirements turn out to be higher than currently anticipated the Enlarged Group or its partners may need to seek additional funds which it may not be able to secure on reasonable commercial terms to satisfy the increased capital expenditure requirements. If this happens, the Enlarged Group's business, cash flow, financial condition and operations may be materially adversely affected.

4.8 ***Exploration activities are capital intensive and there is no guarantee of success***

Exploration activities are capital intensive and their successful outcome cannot be assured. The Enlarged Group intends to undertake exploration activities and incur significant costs with no guarantee that such expenditures will result in the discovery of commercially producible oil or gas. The Enlarged Group intends to explore in geographic areas, where environmental conditions are challenging and costs can be high. The costs of drilling, completing and operating wells are often uncertain. As a result, there may be cost overruns or requirements to curtail, delay or cancel drilling operations because of many factors, including unexpected drilling conditions, pressure or irregularities in geological formations, equipment failures or accidents, adverse weather conditions, compliance with environmental regulations, governmental requirements and shortages or delays in the availability of drilling rigs and the delivery of equipment. Capital expenditure commitments may vary (or be increased) as a result of actual exploration performance. The risk of incurring such costs and the failure of such exploration may adversely affect the Company's profitability.

4.9 ***Appraisal and development results may be unpredictable***

Appraisal results for discoveries are also uncertain. Appraisal and development activities involving the drilling of wells across a field may be unpredictable and not result in the outcome planned, targeted or predicted, as only by extensive testing and production can the properties of the entire field be better understood.

4.10 ***Increase in drilling costs and the availability of drilling equipment***

The oil and gas industry historically has experienced periods of rapid cost increases. Increases in the cost of exploration and development would affect the Enlarged Group's ability to invest directly or indirectly in prospects and to purchase or hire equipment, supplies and oil and gas specific services. In addition, the availability and cost of drilling rigs and other equipment and services, including access to seismic survey equipment and related professionals, is affected by the level and location of drilling activity around the world.

An increase in drilling operations outside or in the Enlarged Group's intended area of operations may reduce the availability, and increase the cost, of such equipment and services to the Enlarged Group and to the companies with which it operates. The reduced availability of such equipment and services may delay the Enlarged Group's ability, directly or indirectly, to exploit reserves and adversely affect the Enlarged Group's operations and profitability.

4.11 ***Delays in production, marketing and transportation***

Various production, marketing and transportation conditions may cause delays in oil and gas production and adversely affect the Enlarged Group's business. Drilling wells in areas remote from distribution and production facilities may delay production from those wells until sufficient reserves are established to justify expenditure on construction of the necessary transportation and production facilities. The Enlarged Group's inability directly or indirectly to complete wells in a timely manner would result in production delays.

The Enlarged Group is also subject to market fluctuations in the prices of oil and natural gas, deliverability uncertainties related to the proximity of reserves to adequate pipeline and processing facilities, and extensive government regulations relating to price, taxes, royalties, licences, land tenure, allowable production, the export of oil and natural gas, and many other aspects of the oil and natural gas business. Moreover, weather conditions may impede the transportation and delivery of oil by sea. Any or all of these factors may result in an adverse impact on the financial returns anticipated by the Enlarged Group.

4.12 ***Decommissioning costs may be greater than initially estimated***

The Enlarged Group, through its licence interests, expects to assume certain obligations in respect of the decommissioning of its wells, fields and related infrastructure. These liabilities are derived from legislative and regulatory requirements concerning the decommissioning of wells and production facilities and require the Enlarged Group to make provisions for and/or underwrite the liabilities relating to such decommissioning. It is difficult to forecast accurately the costs that the Enlarged Group will incur in satisfying its decommissioning obligations. When its decommissioning liabilities crystallise, the Enlarged Group will be liable either on its own or jointly and severally liable for them with any other former or current partners in the field. In the event that it is jointly and severally liable with other partners and such partners default on their obligations, the Enlarged Group will remain liable and its decommissioning liabilities could be magnified significantly through such default. Any significant increase in the actual or estimated decommissioning costs that the Enlarged Group incurs may adversely affect its financial condition.

4.13 ***Natural disasters***

Any interest held by the Enlarged Group is subject to the impacts of any natural disaster such as earthquakes, epidemics, fires and floods etc. No assurance can be given that the Enlarged Group will not be affected by future natural disasters.

4.14 ***Environmental factors***

The Enlarged Group's operations are, and will be, subject to environmental regulation in Nigeria and Niger and any other regions in which the Enlarged Group may operate. Environmental regulations may evolve in a manner that will require stricter standards and enforcement measures being implemented, increases in fines and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their directors and employees. Compliance with environmental regulations could increase the Enlarged Group's costs. Should the Enlarged Group's operations not be able to comply with this mandate, financial penalties may be levied. Environmental legislation can provide for restrictions and prohibitions on spills, releases of emissions of various substances produced in association with oil, condensate and natural gas operations. In addition, certain types of operations may require the submission and approval of environmental impact assessments, such as in respect of the Stubb Creek Field where the Enlarged Group is currently taking appropriate steps to apply for such approval, which the Directors believe will be forthcoming. The Enlarged Group's operations will be subject to such environmental policies and legislation.

Environmental legislation and policy may be periodically amended. Such amendments may result in stricter standards of enforcement and in more stringent fines and penalties for noncompliance. Environmental assessments of existing and proposed projects may carry a heightened degree of responsibility for companies and their directors, officers and employees. The costs of compliance associated with changes in environmental regulations could require significant expenditure, and breaches of such regulations may result in the imposition of material fines and penalties. In an extreme case, such regulations may result in temporary or permanent suspension of production operations. There can be no assurance that these environmental costs or effects, or the failure to obtain the environmental impact assessment for the Stubb Creek Field, will not have a materially adverse effect on the Enlarged Group's future financial condition or results of operations.

4.15 ***Any expansion via acquisition may not be successful and anticipated benefits of acquisitions may not be realised***

The Enlarged Group may enter into future acquisitions, particularly to increase 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. Any such future acquisitions may be achieved through license awards following bidding rounds, transfers of participating or other economic interests by an existing license holder, or direct or corporate acquisitions. No assurance can be given that the Enlarged Group will be able to identify attractive acquisition opportunities or, even if the Enlarged Group does identify attractive opportunities, that it will be able to complete acquisitions, or do so on commercially acceptable terms.

Furthermore, the Enlarged Group could encounter difficulties integrating acquired assets, including operations, systems, management and other personnel and technology associated with such acquired assets with its own. Such difficulties could disrupt the Enlarged Group's ongoing business, distract its management and employees and/or increase its expenses.

4.16 ***Dependence on key executives and personnel***

The future performance of the Enlarged Group will to a significant extent be dependent on its ability to retain the services and personal connections or contacts of key executives, to attract, recruit, motivate and retain other suitably skilled, qualified and industry experienced personnel to form a high caliber management team and to develop a succession plan for key executives. Such key executives are expected to play an important role in the development and growth of the Enlarged Group, in particular, by maintaining good business relationships with regulatory and governmental departments and essential partners, contractors and suppliers.

Further, the Enlarged Group may struggle to recruit key personnel required to run an exploration and appraisal programme and other important members of the workforce required to run a full exploration or appraisal programme. Shortages of labour, or of skilled workers, may cause delays or other stoppages during exploration and appraisal activities. Many of the Enlarged Group's competitors are larger, have greater financial and technical resources, as well as staff and facilities, and have been operating in a market-based competitive economic environment for much longer than the Enlarged Group.

There can be no assurance that the Enlarged Group will retain the services of any key executives, advisers or personnel who have entered into service agreements or letters of appointment with the Enlarged Group. The loss of the services of any of the key executives, advisers or personnel may have a material adverse effect on the business, operations, relationships and/or prospects of the Enlarged Group. In particular, given the importance of the direction and leadership of its existing Chief Executive Officer as founder of the Company, his local knowledge and relationships in the oil and gas industry in Nigeria and Niger and his industry expertise, the future success of the Enlarged Group is, to an extent, dependent upon the continued service of the Chief Executive Officer. The Enlarged Group currently has no succession plan in place and, therefore, there is a risk that the unexpected departure or loss of this individual could have a material adverse effect on the business, financial condition (including on the ability to drawdown on the facility described in paragraph 9.2.10(b) of Part 10 of this document) 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.

4.17 ***Labour and health & safety***

Developing oil and gas resources and reserves into commercial production involves a high degree of risk. The Enlarged Group's exploration operations are subject to all the risks common in its industry. These hazards and risks include encountering unusual or unexpected rock formations or geological pressures, geological uncertainties, seismic shifts, blowouts, oil spills, uncontrollable flows of oil, natural gas or well fluids, explosions, fires, improper installation or operation of equipment and equipment damage or failure, including failure to comply with regulatory requirements expected of a Western country (such as comprehensive health and safety processes). Personal injuries suffered as a result of the foregoing are likely to be exacerbated as a result of a lack of access to medical care facilities and healthcare professionals.

If any of these types of events were to occur, they could result in loss of production, environmental damage, injury to persons and loss of life.

They could also result in significant delays to drilling programmes, a partial or total shutdown of operations, significant damage to equipment owned or used by the Enlarged Group and personal injury, wrongful death or other claims related to loss being brought against the Enlarged Group. These events could result in the Enlarged Group being required to take corrective measures, incurring significant civil liability claims, significant fines or penalties as well as criminal sanctions potentially being enforced against the Enlarged Group and/or its officers. The Enlarged Group may also be required to curtail or cease operations on the occurrence of such events. Any of the above could have a material adverse effect on the Enlarged Group's business, prospects, financial condition or results of operations.

While the Enlarged Group has implemented certain policies and procedures to identify and mitigate such hazards, develop appropriate work plans and approvals for high-risk activities and prevent accidents from occurring, these procedures may not be sufficiently robust or appropriately followed by the Enlarged Group's staff or third-party contractors to prevent accidents.

4.18 ***Project development risks***

There can be no assurance that the Enlarged Group will be able to manage effectively the expansion of its operations or that the Enlarged Group's current personnel, systems, procedures and controls will be adequate to support the Enlarged Group's operations. Any failure of the Board to manage effectively the Enlarged Group's growth and development could have a material adverse effect on the Enlarged Group's business, financial condition and results of operations. There is no certainty that all or, indeed, any of the elements of the Enlarged Group's current strategy will develop as anticipated and that the Enlarged Group will be profitable.

4.19 ***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. 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. Emerging markets such as Nigeria are subject to rapid change and that the information set forth herein may become outdated relatively quickly.

Financial turmoil in an emerging market country tends to adversely affect companies operating within those markets, as investors move their money to more stable, developed markets. As has happened in the past, financial problems or an increase in the perceived risks associated with investing in emerging economies could dampen foreign investment in Nigeria and adversely affect the Nigerian economy. In addition, during such times of loss of market confidence, companies that operate in emerging markets can face severe liquidity constraints as foreign funding sources are withdrawn.

As a result of the Enlarged Group's operations in Nigeria and Niger, it 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 it 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 thus 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 to it.

In addition, financial turmoil in any emerging market country or the capital markets generally could adversely affect the Enlarged Group's business.

4.20 ***Tax risks***

The Enlarged Group has subsidiaries located in multiple jurisdictions and has relied on external professional advice in relation to the applicable taxation regime in each jurisdiction. The Enlarged Group cannot be certain that this advice will ultimately prove to be correct. 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. Any such changes, or the application of taxes where not anticipated by the Enlarged Group, may have a material adverse effect on the Enlarged Group's financial condition and results of operations.

4.21 ***Exchange rate fluctuations***

Currency fluctuations may affect the Enlarged Group's operating cashflow since certain of its costs and revenues are denominated in currencies other than Pounds Sterling such as US Dollars, Euros, Naira and XOF. Fluctuations in exchange rates between currencies in which the Enlarged Group operates may cause fluctuations in its cashflows and financial results (which are reported in US Dollars). In particular, under the terms of the Enlarged Group's gas sales agreements, which are US Dollar denominated, the customer has the option to settle in Naira at the relevant prevailing exchange rate immediately prior to settlement and the Enlarged Group is exposed to any adverse exchange rate differential or movement in exchange rate in converting Naira back into US Dollars, for example, for servicing US Dollar denominated debt. The Enlarged Group does not currently have a foreign currency hedging policy in place. If and when appropriate, the adoption of such a policy will be considered by the Board.

The Company's share price is quoted on the London Stock Exchange in Pounds Sterling. As a consequence, shareholders may experience fluctuation in the market price of the Ordinary Shares as a result of, amongst other factors, movements in the exchange rate between Pounds Sterling, US Dollars, Euros, Naira and XOF.

4.22 ***Insurance coverage and uninsured risks***

While the Board will determine appropriate insurance coverage from time to time, it may elect not to have insurance for certain risks due to the high premium costs associated with insuring those risks or for other reasons, including an assessment in some cases that the risks are remote.

No assurance can be given that the Enlarged Group will be able to obtain insurance coverage at reasonable rates (or at all), or that any coverage it or the relevant operator obtains and proceeds of insurance will be adequate and available to cover any claims arising. The Enlarged Group may become subject to liability for pollution, blow-outs or other hazards against which it has not insured or cannot insure, including those in respect of past activities for which it was not responsible. The Enlarged Group will exercise due care in the conduct of its business and obtain insurance prior to commencing operations in accordance with industry standards to cover certain of these risks and hazards. However, insurance is subject to limitations on liability and, as a result, may not be sufficient to cover all of the Enlarged Group's losses. The occurrence of a significant event against which the Enlarged Group is not fully insured, or the insolvency of the insurer of such event, could have a material adverse effect on the Enlarged Group's business, financial condition, results of operations and prospects. Any indemnities the Enlarged Group may receive from such parties may be difficult to enforce if such sub-contractors, operators or joint venture partners lack adequate resources. In the event that insurance coverage is not available or the Enlarged Group's insurance is insufficient to fully cover any losses, claims and/or liabilities incurred, or indemnities are difficult to enforce, the Enlarged Group's business and operations, financial results or financial position may be disrupted and adversely affected. Further, even where the Enlarged Group is insured, its contractors may themselves be insufficiently insured, or uninsured, in respect of damage they may cause to the Enlarged Group's property or operations. In such cases, the Enlarged Group may be required to incur additional costs to extend its cover to its contractors, from whom it may be unsuccessful in recovering such costs in full or at all.

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

Operational insurance policies are usually placed in one-year contracts and the insurance market can withdraw cover for certain risks which can greatly increase the costs of risk transfer. Such increases are often driven by factors unrelated to the Enlarged Group such as well control elsewhere in the world and weather damage.

4.23 ***Professional advisers***

The Directors and the Enlarged Group have relied upon advice from various professional advisers engaged by the Enlarged Group in relation to the preparation of this Admission Document. Such professional advisers' liability is subject to limitations. Accordingly, in the event any such advice proves to be have been incorrect, any amounts recoverable from the relevant adviser(s) may not be sufficient to cover all of the Enlarged Group's resulting losses. This could have a material adverse effect on the Enlarged Group's business and operations, financial condition and prospects.

4.24 ***Future litigation***

From time to time, the Enlarged Group may be subject, directly or indirectly, to litigation arising out of its proposed operations. Damages claimed under such litigation may be material or may be indeterminate, and the outcome of such litigation may materially impact the Enlarged Group's business, results of operations or financial condition. While the Enlarged Group assesses the merits of each lawsuit and defends itself accordingly, it may be required to incur significant expenses or devote significant resources to defending itself against such litigation. In addition, the adverse publicity surrounding such claims may have a material adverse effect on the Enlarged Group's business.

5. Risks relating to operating in Nigeria

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

The Enlarged Group must 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.

The unstable pricing, and possible scarcity, of fuel for power generation in Nigeria also increases the operational challenges businesses face and adding to the potential volatility in operating costs.

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 5.8 and 5.9 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 Nigerian government has significant influence over, and dependency upon, Nigeria's oil and gas industry, exposing the Enlarged Group to adverse sovereign action by the Nigerian government***

As per the latest report on Nigeria from the U.S. Energy Information Administration (EIA), according to the International Monetary Fund (IMF), oil and natural gas export revenue, which was almost US$87 billion in 2014, accounted for 58 per cent. of Nigeria's total government revenue in that year. Oil and natural gas revenue is the country's main source of foreign exchange, making up more than 95 per cent. of Nigeria's total exports to the world in 2014. The Nigerian government's ownership of Nigeria's mineral wealth is reinforced by an array of laws and regulations, including the Petroleum Act, which gives the MPR the authority to issue petroleum exploration and mining licenses and approve to a great extent the ownership, operatorship and holding of interests in such licences. In addition, NNPC is a government-controlled corporation that directly participates in joint ventures for the exploration and production of hydrocarbon reserves and facilitates participation in the oil and gas industry. As a consequence, the Nigerian government plays a key role in determining the extent to which anyone participates in the Nigerian oil and gas industry. There can be no assurance that the Enlarged Group will continue to benefit from the support of the Nigerian government, which could have a material adverse effect on the Enlarged Group's business, results of operations, cash flows, financial condition and prospects.

Accordingly, petroleum companies in Nigeria face the risks of expropriation or re-nationalization, breach or abrogation of project agreements, application to such companies of laws and regulations from which they were intended to be exempt, denials of required permits and approvals, increases in royalty rates and taxes that were intended to be stable, application of exchange or capital controls, and other risks. Possible future changes in the Nigerian government, major policy shifts or increased security arrangements in Nigeria could have, to varying degrees, a material adverse effect on the Enlarged Group's business, results of operations, cash flows, financial condition and prospects.

5.5 ***Production of oil in Nigeria may be impacted by OPEC and other production quotas***

Nigeria is a member of OPEC, which, from time to time constrains its members' ability to produce oil through the imposition of production quotas. NNPC allocates production quotas among oil producers based on the aggregate technical production limits of all producing wells, which are negotiated between the producer and the Nigerian government. In the event that technical production exceeds Nigeria's OPEC quota, the quota is allocated to the producers on a *pro rata* basis based on their respective technical production levels. If production allocations are exceeded, it is possible to apply for additional quotas from the Nigerian government, but there can be no assurance that the additional quotas will be granted. Nigeria also has the power to implement export quotas. As a result, the Enlarged Group may be constrained in exporting oil through such quotas in the future, which could have a material adverse effect on the Enlarged Group's business, prospects, results of operations, cash flows, financial condition and prospects.

5.6 ***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.

5.7 ***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.

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

Following 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. 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. 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 future elections, the next one of which is currently due in 2023, 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.

Religious differences, particularly between the mainly Muslim north and broadly Christian south, pose additional risks to the stability of Nigeria and the political landscape. Certain northern states have adopted Sharia law since the return to civilian rule in 1999, which has resulted in further alienation of the Christian minorities in these states. Hundreds of lives have been lost in a series of terrorist attacks, primarily by way of bombings carried out by religious militia groups against both civilians and state institutions. In addition, religious militia groups have carried out armed attacks and kidnappings against foreigners working in Nigeria.

Furthermore, Boko Haram, a militant Islamist group operating in northern Nigeria, has escalated insurgency attacks since the beginning of 2011 and has become increasingly active engaging in mass kidnappings, raids on villages with high fatalities and cross border attacks in Cameroon. Suspected members of Boko Haram have reportedly conducted kidnappings and attacks in the northeastern part of the country and the Federal Capital Territory.

While terrorist attacks linked to religious and/or ethnic differences have in the past primarily been carried out in the north of the country, no assurances can be given that such violence will not spread to southern Nigeria where the Enlarged Group's operations are based. These conflicts may adversely affect Nigeria's political stability which may, in turn, affect the Enlarged Group's business, results of operations, cash flows, financial condition and prospects.

5.9 ***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.

There is a risk that, in the future, and in spite of the Nigerian government's efforts (which have included offering an amnesty to militants who surrender their weapons), militant acts in the Niger Delta may continue to be directed at oil and gas industry participants and there is no assurance that militant acts will not occur in the future.

If the Enlarged Group, its employees or employees of its operating partners are the subject of any attacks, kidnappings or other security threats, the Enlarged Group's operations and production of oil and gas in the Niger Delta could be materially adversely affected. Unrest in the Niger Delta region may lead to lower Nigerian oil and gas production, deter foreign direct investment, lead International Oil Companies to curtail their operations in Nigeria or lead to increased political instability and unrest, and such unrest could have a material adverse effect on Nigeria's economy. The fear of militant attacks could have an adverse effect on the Enlarged Group's ability to adequately staff and/or manage our operations and could substantively increase the costs of doing so. In addition, any militant action against the Enlarged Group's assets or operations could result in significant damage to the environment, negatively impact the Enlarged Group's relationships with local communities and result in a temporary or permanent closure of all or part of those facilities.

The occurrence of any of the above could have a material adverse effect on our business, results of operations, cash flows, financial condition and prospects.

5.10 ***Any gas flaring in violation of the gas flaring regulations 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 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 feet of gas flared.

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

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.

5.12 ***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.

5.13 ***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 including, in particular, any licence fees that become due. Whilst the Enlarged Group seeks to ensure that it has good title to the participating interests that it owns, it 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.

As at the date of this document, the DPR has requested a licence renewal fee of US$1 million for a 10 year renewal of the Uquo FOA until 2026. The requested renewal fee has not yet been paid by Frontier, and as such the DPR is unable to confirm that the Uquo Field licence is in good standing. The Company intends to pay any renewal fees that are ultimately found to be due.

5.14 ***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 Federal Inland Revenue Service'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.

5.15 ***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 Petroleum Profits Tax

Act. The Nigerian withholding tax rate on dividends is generally 10 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.

5.16 ***Foreign subsidiaries***

The Enlarged Group conducts all of its operations in Nigeria through its Nigerian incorporated and tax resident subsidiaries. The ability of these Nigerian subsidiaries 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 the jurisdiction in which any other Group company operates, and the introduction of exchange controls or repatriation restrictions or the availability of hard currency to be repatriated.

5.17 ***Failure to adequately address actual and perceived risks of corruption may adversely affect Nigeria's economy and ability to attract foreign direct investment and we may be exposed to liability under anti-corruption and anti-bribery legislation, including the UK Bribery Act***

Although Nigeria has implemented and is pursuing major initiatives to prevent and fight corruption and unlawful enrichment, corruption remains a significant issue in Nigeria. Nigeria is ranked 146 out of 180 countries in Transparency International's 2019 Corruption Perceptions Index and placed 131 out of 190 in the World Bank's Doing Business 2020 report.

There have been a number of high profile convictions for corruption, including that of a former Inspector General of the Police, some ex-state governors and two former executives of Afren plc, a UK LSE listed oil and gas company doing business in Nigeria. In addition, a number of ministers and judges have been dismissed and a number of ex-state governors are facing corruption charges. In addition, customary practices in Nigeria, such as the giving of significant gifts at important life events such as marriages or funerals, may be potentially used as a way to influence the Enlarged Group's employees, agents, intermediaries or consultants, or may raise a perception of illegal activity even when none exists. Failure to address these issues, continued corruption in the public sector and any future allegations, or perceived risk, of corruption in Nigeria could have an adverse effect on the Nigerian economy and may have a negative effect on Nigeria's ability to attract foreign investment.

The Enlarged Group is subject to anti-corruption and anti-bribery legislation and regulations, including the UK Bribery Act, the FCPA and other laws and regulations 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 other benefits. By doing business in Nigeria, the Enlarged Group could face, directly or indirectly, corrupt demands by officials, militant groups or private entities. Consequently, the Enlarged Group faces the risk that one or more of the Enlarged Group's employees, agents, intermediaries or consultants may make or receive unauthorised payments given that such persons may not always be subject to the Enlarged Group's control. In addition, it is possible that the Enlarged Group could be held liable for successor liability for FCPA violations committed by companies in which the Enlarged Group has invested in or acquired or may invest or acquire. Although the Enlarged Group has policies and procedures designed to ensure that the Enlarged Group, its employees, agents, intermediaries and consultants comply with the UK Bribery Act, the FCPA and all applicable Nigerian anti-corruption legislation, there is no assurance that such policies or procedures will work effectively all of the time or protect the Enlarged Group against liability under any such legislation for actions taken by our agents, employees, intermediaries and consultants with respect to the Enlarged Group's business. If the Enlarged Group is not in compliance with the UK Bribery Act, the FCPA or other laws governing the conduct of business with Nigerian government entities (including local laws), the Enlarged Group 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 the UK Bribery Act, the FCPA or other anti-corruption or anti-bribery 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. Any such findings, or any alleged or actual involvement in corrupt practices or other illegal activities by the Enlarged Group or its commercial partners or anyone with whom the Enlarged Group conducts business could damage its reputation and its ability to do business, including by affecting the Enlarged Group's rights and title to assets or by the loss of key personnel, and together with any increased compliance costs, could adversely affect the Enlarged Group's business, results of operations, cash flows, financial condition and prospects.

5.18 ***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.

There can be no assurance that contracts, joint ventures, licenses, license applications or other legal arrangements will not be adversely affected by the actions of Nigerian government authorities and the effectiveness and enforcement of such arrangements in Nigeria. A number of the asset and joint venture documents to which we are a party are not standard form documents, which makes interpretation of disputed provisions less certain. These and other issues arising out of Nigeria's legal system subject the Enlarged Group's business to greater risks and uncertainties than if the Enlarged Group's operations were conducted in jurisdictions with a more mature legal system.

5.19 ***Nigeria is a federal state, and the Enlarged Group's operations are located across two states, exposing the Enlarged Group to varying, potentially adverse, state and local government policies***

The Enlarged Group's operations are located across two states of Nigeria, both of which have their own governments. Within those states, there are also multiple local government authorities within the Enlarged Group's areas of operation. In addition, the Enlarged Group presently contracts with certain state-owned entities, such as Ibom Power, which is owned by Akwa Ibom State. Each of these states has a varying political dynamic. In addition, political changes at the state and local level can affect the Enlarged Group's contracts with these local governments or entities they own or control, including the potential risk of expropriation. Further, while the powers of the various tiers of government to levy and collect taxes are set forth in the Nigerian constitution, it is not unusual for state and local government agencies to seek to levy and collect taxes that they are not constitutionally authorised to levy and collect. These factors, combined with potential conflicts between federal, state and local governments, could have a material adverse effect on the Enlarged Group's business, results of operations, financial position, cash flows and prospects.

6. Risks relating to operating in Niger

6.1 ***Doing business in Niger***

Doing business in Niger brings with it a wide variety of risks, including political, legal, regulatory, social and economic risks as further described below.

6.2 ***Risk of crime and corruption***

Countries in West Africa experience high levels of criminal activity and governmental and business corruption. Oil and gas companies operating in West Africa may be particular targets of criminal or terrorist actions. Criminal, corrupt or terrorist action against the Enlarged Group and its directly or indirectly held properties or facilities could have a material adverse effect on the Enlarged Group's business, results of operations or financial condition. In addition, the fear of criminal or terrorist actions against the Enlarged Group could have an adverse effect on the ability of the Enlarged Group adequately to staff and/or manage its operations or could substantially increase the costs of doing so. Niger faces a threat of terrorism as a result of its proximity and accessibility to various regional Islamist insurgencies. Whilst these insurgencies have not impacted Savannah's operations historically, there can be no guarantee this continues to be the case in the future.

Furthermore, alleged or actual involvement in corrupt practices or other illegal activities by the Enlarged Group or by Savannah's potential future joint venture partners, or others with whom the Enlarged Group directly or indirectly conducts business, could also damage the Enlarged Group's reputation and business and adversely affect the Enlarged Group's financial condition and results of operations. The UK Bribery Act 2010 ("**Bribery Act**") came into force in July 2011. Under the terms of the Bribery Act, an unlimited fine may be imposed on companies (which could potentially include the Company and other members of its Group) where they have failed to take appropriate steps ("**Adequate Procedures**") to ensure that the company and its associated persons, as defined in the Bribery Act (including, but not limited to, employees, subsidiaries, joint ventures, and agents) are not involved in any corrupt practices. There is concern in the oil and gas industry that, following the letter of the law, the Bribery Act prohibits certain practices which are not covered by (a) the US Foreign Corrupt Practices Act 1977 (the "**FCPA**"), or (b) Nigerien anti-corruption legislation and regulations (to which the Enlarged Group is bound), but which are regarded as standard industry practice (for example, facilitation payments). It may not be possible for the Enlarged Group to detect or prevent every instance of fraud, bribery or corruption. Failure to detect or prevent any such instances may expose the Enlarged Group to potential civil or criminal penalties under relevant applicable law and to reputational damage, which may have a material adverse effect on the Enlarged Group's business, prospects, financial condition or results of operations.

6.3 *Political, economic, fiscal, legal, regulatory and social environment risk*

The Enlarged Group's interests in Niger are likely to be exposed to political, economic, fiscal, legal, regulatory and social environment risk. The Enlarged Group's business will involve a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. These risks include, but are not limited to, corruption, civil strife or labour unrest, armed conflict, terrorism, limitations or price controls on oil exports, and limitations or the imposition of tariffs or duties on imports of certain goods. If the existing body of laws and regulations in Niger are interpreted or applied, or relevant discretions exercised, in an inconsistent manner by the courts or applicable regulatory bodies, this could result in ambiguities, inconsistencies and anomalies in the enforcement of such laws and regulations, which, in turn, could hinder the long-term planning efforts of the Enlarged Group and may create uncertainties in its operating environment.

Exploration and development activities in developing countries may require protracted negotiations with host governments, national oil companies and third parties and may be subject to economic and political risks referred to above and expropriation, nationalisation or renegotiation of existing contracts. The two main protections granted to Savannah under the Savannah PSCs are (i) the stability of the legislation and the terms agreed under the Savannah PSCs and the commitment that the Nigerien Government 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 and the Savannah PSCs and (ii) the arbitration procedure according to which any dispute relating to the Savannah PSCs which cannot be settled amicably shall ultimately be resolved by means of arbitration conducted in accordance with the Arbitration Rules of the International Centre for Settlement of Investment Disputes (ICSID Rules) in accordance with the Convention on the settlement of investment disputes between States and nationals of other States, the "Washington Convention". The Savannah PSCs each provide 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. The Savannah PSCs specifically provide for any such arbitration to be heard in Paris, France.

The Nigerien Government owns the country's mineral resources and grants hydrocarbon exploration and production rights under fixed term production sharing contracts, which can be renewed in accordance with their terms. It thus retains control over the exploration and exploitation of hydrocarbon reserves. Any adverse changes in the Nigerien Government's policy with respect to the oil and gas industry, including any which may occur following the proposed review of the current Petroleum Code, may adversely impact the interests of the Enlarged Group. Further, the strategy and business of the Enlarged Group in Niger depend on it maintaining good relationships and cooperating with the relevant Nigerien authorities. While the Company believes that it has an effective working relationship with the Niger authorities, there is no guarantee that this positive relationship will continue or that actions by current or future governments will not seriously affect the business or financial position of the Enlarged Group. This relationship could be adversely impacted by future changes in the personnel or management of the Enlarged Group or the Nigerien authorities.

6.4 ***Uncertainties in the interpretation and application of laws and regulations***

A number of the Enlarged Group's principal agreements, including the Savannah PSCs, are governed by Nigerien 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 (ICSID Rules) in accordance with the Convention on the settlement of investment disputes between States and nationals of other States, the "Washington Convention" (the Savannah PSCs specifically providing for any such arbitration to be heard in Paris, France). 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; and (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.

In Niger, the state asserts ownership of minerals and consequently, subject to the terms agreed in the Savannah PSCs, retains control of (and, in many cases, participates in) the production of hydrocarbon reserves. Transfers of interests typically require government approval, which may delay or otherwise impede such transfers.

6.5 ***Licensing and other regulatory requirements in Niger***

The Enlarged Group's direct and/or indirect intended future operations will be subject to, licences, production sharing contracts, regulations and approvals of governmental authorities for exploration, development, construction, operation, production, marketing, pricing, transportation and storage of oil, taxation, and environmental and health and safety matters. The Enlarged Group cannot guarantee that such documents applied for will be granted or, if granted, will not be subsequently withdrawn or made subject to possibly onerous conditions, or their availability to the Enlarged Group or its associated companies may adversely affect the Enlarged Group's assets, plans, targets and projections. A block authorisation may be revoked by the relevant regulatory authority if, *inter alia*, an interest holder defaults on its block obligations.

The Enlarged Group will be subject to extensive government laws and regulations (which may be subject to change) governing prices, taxes, royalties, allowable production, waste disposal, pollution control and similar environmental laws, the export of oil and many other aspects of the oil business. There can be no assurance that the actions of present or future governments in Niger, or of governments of other countries in which the Enlarged Group may operate in the future, will not materially adversely affect the Enlarged Group's ability to comply with such laws and regulations or that there will not be a challenge to the Enlarged Group's title to any interest it may have in Niger. However, in the Savannah PSCs, the Nigerien Government grants to Savannah Niger a guarantee of the stability of the legal, economic, tax, customs duty, financing and foreign exchange regimes applicable to the Savannah PSCs and to the petroleum operations carried out by virtue of the Savannah PSCs.

In order to ensure continuity of its activities in Niger, the Enlarged Group needs to obtain the renewal of the Savannah PSCs after the initial phase. Despite the guarantees given by the Government of Niger in the Savannah PSCs, possible changes in political and institutional will may result in the Government rejecting any request for the renewal or extension of the Savannah PSCs and licenses, thereby leaving Savannah without valid title. Notwithstanding the right to dispute settlement by arbitration, such a refusal by the Nigerien Government to extend the Savannah PSCs would severely impact the operations of the Enlarged Group.

6.6 ***Adverse sovereign action involving expropriation or renationalisation***

The oil and gas industry is central to the economy and future prospects for development in Niger. Therefore, the industry can be expected to be the focus of continuing attention and debate. In certain developing countries, petroleum companies have faced the risks of expropriation or re-nationalisation, breach or abrogation of project agreements, application to such companies of laws and regulations from which they were intended to be exempt, denials of required permits and approvals, increases in royalty rates and taxes that were intended to be stable, application of exchange or capital controls, and other risks.

As with many countries, possible future changes in the government, major policy shifts or increased security arrangements could have, to varying degrees, an adverse effect on the value of investments.

These factors could materially adversely affect the Enlarged Group's business, prospects or financial results.

In the event of a dispute arising in connection with its interests, the Enlarged Group is likely to be subject to the jurisdiction of the courts of Niger. The effectiveness of and enforcement of such contracts and relationships with parties in these jurisdictions cannot be assured. Consequently, the Enlarged Group's exploration, development and production activities could be substantially affected by factors beyond the Enlarged Group's control, any of which could have a material adverse effect on the Enlarged Group.

7. Risks relating to the Ordinary Shares

7.1 ***Share price volatility and liquidity***

The Company's entire issued share capital is admitted to trading on AIM but 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. An investment in shares traded on AIM carries a higher risk than those listed on the Official List.

The Company is principally aiming to achieve capital growth and, therefore, Ordinary Shares may not be suitable as a short-term investment. Consequently, the share price may be subject to greater fluctuation on small volumes of shares traded, and thus the Ordinary Shares may be difficult to sell at a particular price. Prospective investors should be aware that the value of an investment in the Company may go down as well as up and that the market price of the Ordinary Shares may not reflect the underlying value of the Company. There can be no guarantee that the value of an investment in the Company will increase. Investors may therefore realise less than, or lose all of, their original investment.

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; (i) the performance of the Company and the overall stock market; (ii) large purchases or sales of Ordinary Shares by other investors; (iii) results of exploration, development and appraisal programmes and production operations; (iv) changes in analysts' recommendations and any failure by the Enlarged Group to meet the expectations of the research analysts; (v) changes in legislation or regulations and changes in general economic, political or regulatory conditions (particularly in Nigeria and/or Niger); and (vi) other factors which are outside of the control of the Company.

7.2 ***Dilution***

Shareholders not participating in future offerings may be diluted and pre-emptive rights may not be available to Shareholders, including, but not limited to Shareholders resident in jurisdictions with restrictions having the effect that they will not be granted subscription rights in connection with, or be able to subscribe for new shares in, such offerings. Statutory pre-emptive rights have been waived up to certain stated amounts as detailed in the Company's 2019 AGM circular. The Company may in the future issue warrants and/or options (in addition to the existing awards made by the Company under its share incentive scheme, which are set out in Part 10 of this document) to subscribe for new Ordinary Shares, including (without limitation) to certain advisers, employees, directors, senior management and consultants. The exercise of such warrants and/or options would result in dilution of the shareholdings of other investors.

7.3 ***Dividends***

The Enlarged Group has previously announced its intention to commence payment of an annual dividend. The Enlarged Group intends to provide further information on its intended forward dividend policy in due course, however there can be no assurance as to the level of future 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.

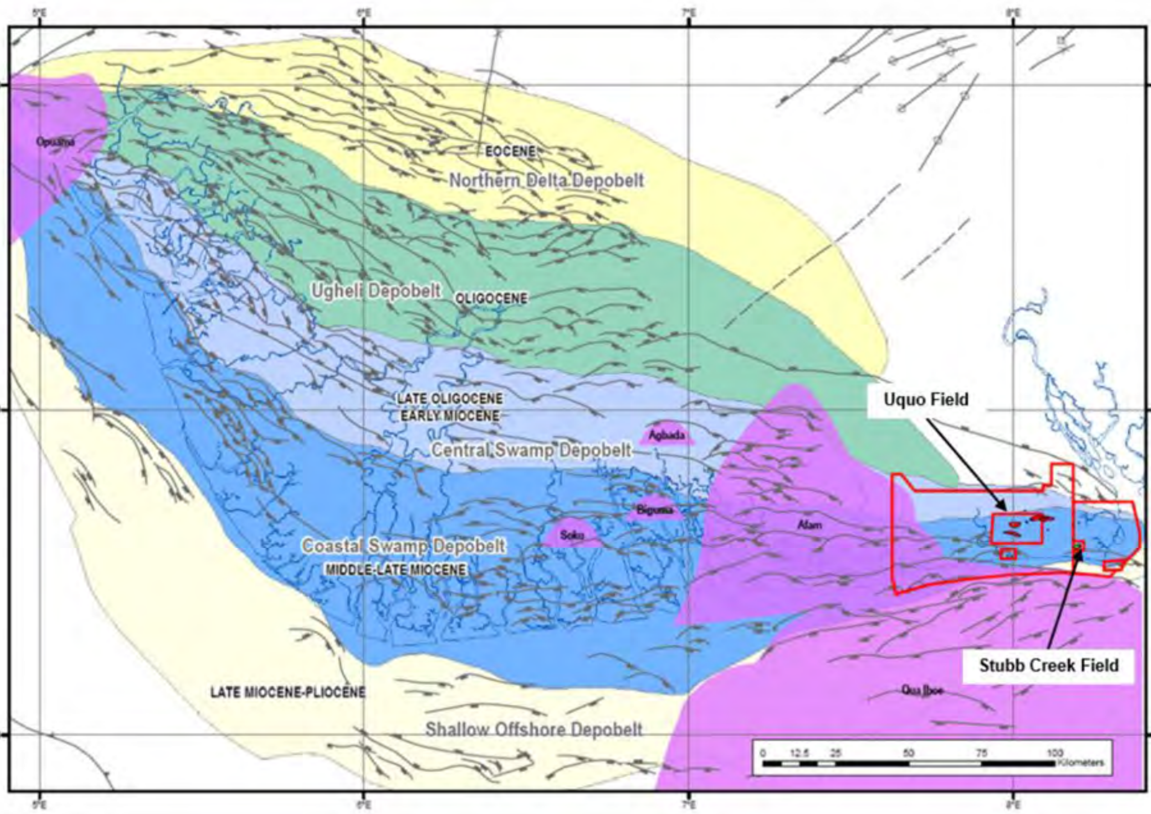
Although the Directors will seek to minimise the impact of the risk factors listed above, investment in the Enlarged Group should only be made by investors able to sustain a total loss of their investment.

PART 4

NIGERIAN ASSET OVERVIEW

The Nigerian Assets, comprising the Uquo and Stubb Creek marginal fields and associated processing and transportation infrastructure owned by Accugas Limited, are located onshore in the southern part of the country, in the south east of the prolific petroleum province of the Niger Delta, as shown in Figure 15 below. In addition to its high-ranking world petroleum status, with some 37.5 billion barrels of Proved oil reserves as of the end of 2018, Nigeria holds the largest gas resources in the African continent with some 188.8 Tscf of Proved reserves[7], and these have remained largely un-exploited. 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 15, Niger Delta – Regional Setting



Source: Nigeria CPR

The Niger Delta Basin is a highly prolific, mature petroleum province, extending from the onshore delta onto the marine shelf and slope (Figure 15). Late Jurassic to Early Cretaceous rifting controlled initial development of the delta and its main depocenter, while the Tertiary aged sedimentary pile has been prograding south-westwards since Eocene times (c. 55 Mybp). The Tertiary age Niger Delta now covers an area of about 75,000 km^2, and has a sedimentary thickness of up to 12 km.

The Nigerian Assets 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 depocenter (Figure 15). Traps are present in a variety of combinations of rollover structures with different faulting styles.

The principal petroleum bearing section 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

[7] BP Statistical Review of World Energy, 2019

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.

1. Licence Interests

- Savannah holds an indirect 80 per cent. interest in gas development and production in the Uquo Field through its 80 per cent. ownership in Uquo HoldCo. The remaining 20 per cent. interest is held indirectly by AIIM. Savannah does not have an equity interest in any current or future oil production at the Uquo Field, other than liquids associated with the production and processing of the gas.

- Savannah also holds an indirect 51 per cent. operated interest in the Stubb Creek Field, through its 100 per cent. economic ownership of Universal, an indigenous Nigerian E&P company.

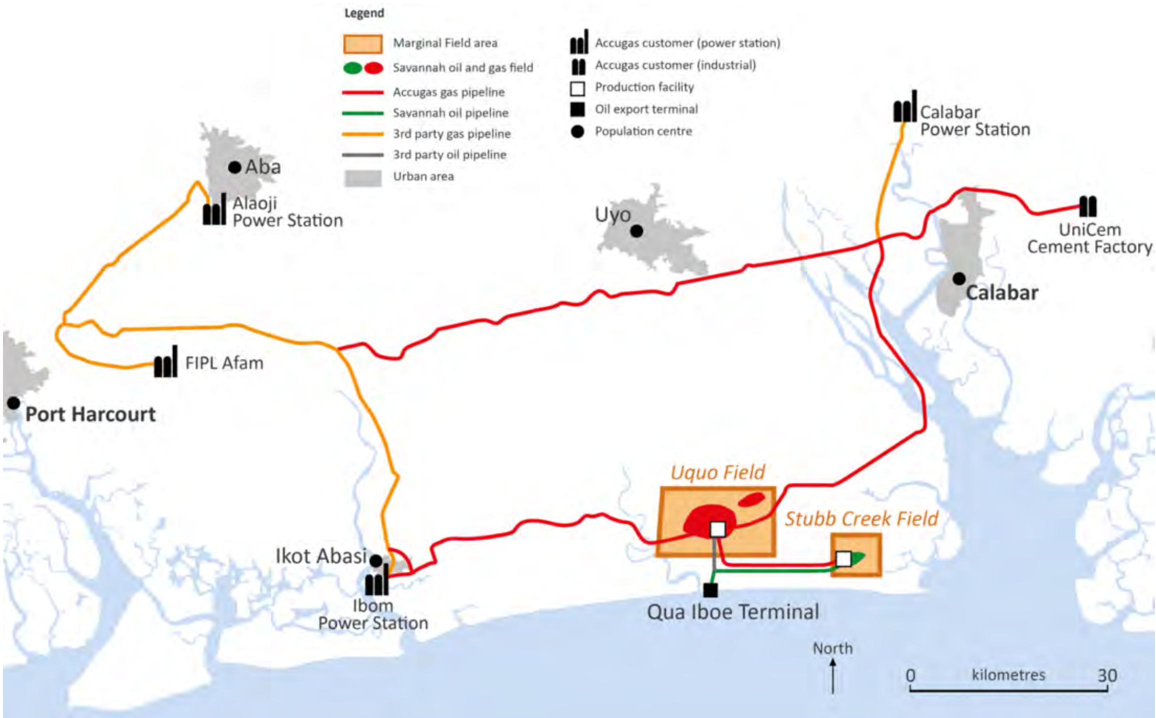
- In addition, Savannah holds an indirect 80 per cent. interest in the Accugas Midstream Business, which owns and operates the Uquo CPF (the 200 MMscfpd gas processing facility) and c. 260 km pipeline network. The Accugas Midstream Business has in place various Gas Sales Agreements with downstream gas buyers. AIIM (via African Midstream Holdings Mauritius) holds the remaining 20 per cent. interest.

Figure 16, Savannah's current licence interests

	Operator	*Participating Interest*	*Status*	*Licence Expiry Date*	*Licence Area*
Uquo Gas	Frontier	40% (100% economic interest in the gas project)	Production	2035 (see Risk Factor 5.13)	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

Both of the Uquo Field and Stubb Creek Field are currently in production. Oil and condensate from both the Uquo Field and Stubb Creek Field is exported through QIT which lies a short distance to the south of the Uquo Field, as shown in Figure 17. A number of large industrial gas consumers are located in this part of the Delta, including power stations at Ibom and Calabar and a cement plant at Calabar; these are connected to the Uquo Field via Accugas Limited's gas pipeline network.

Figure 17, Map of Nigerian Assets, South East Niger Delta



Source: Savannah, 2020

2. Reserves and Resources

Gross field and net attributable oil and gas reserves in the two upstream assets, as determined by CGG in the Nigeria CPR, are shown in Figure 18 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 4.2 MMbbl oil and condensate and 400.7 Bscf gas in net attributable 2P (Proved plus Probable) reserves, as of 1 November 2019. The small volume of liquids at Uquo (0.5 MMbbl net 2P reserves) are condensates produced in conjunction with gas. Savannah has no rights to any separate oil development or production in that field.

Figure 18, Reserves (as at 1 November 2019)

	Gross on Licence			*Net Attributable*			*Operator*
	1P	*2P*	*3P*	*1P*	*2P*	*3P*	
Oil and Condensate Reserves							
Uquo	0.4	0.7	1.0	0.3	0.5	0.8	SUGL
Stubb Creek	7.9	15.4	25.0	1.7	3.7	6.4	Universal
Total (MMstb)	8.3	16.1	26.0	2.0	4.2	7.2	
Gas Reserves							
Uquo	301.0	500.9	721.7	240.8	400.7	577.4	SUGL
Total (Bscf)	301.0	500.9	721.7	240.8	400.7	577.4	

Source: Adapted from the Nigeria CPR

Contingent Resources, as determined by CGG in the Nigeria CPR, are summarised in Figure 19 below. Additional gas at the Uquo Field, and the large undeveloped gas resource at the Stubb Creek Field, are considered by CGG to have a high probability of future commercial development (>75 per cent.) and 351.7 Bscf of gas is attributable to Savannah in the 2C, “Best Estimate”, case.

Figure 19, Contingent Resources

	Gross on Licence			Net Attributable			Chance of	
	1C	*2C*	*3C*	*1C*	*2C*	*3C*	*Development*	*Operator*
Oil (MMstb)								
Stubb Creek	–	–	–	–	–	–		Universal
Gas (Bscf)								
Uquo	45.0	72.5	115.6	36.0	58.0	92.5	>75%	SUGL
Stubb Creek	364.9	515.3	680.3	208.0	293.7	387.8	>75%	Universal
Total (Bscf)	409.9	587.8	795.9	244.0	351.7	480.3		

Source: Adapted from the Nigeria CPR

3. Economic Evaluation

The NPV (at 10 per cent. discount rate) of discounted cash flows derived from the exploitation of Reserves as at 1 November 2019 is shown in Figure 20 below. The values stated are net to Savannah's interest after deduction of capex, opex, taxes and royalties (but before debt service). Gas from the Uquo Field is sold to the Accugas Midstream Business under the Upstream GSA, and, for the purposes of the economic evaluation performed by CGG in the Nigeria CPR, it is assumed that Accugas Limited sells the processed gas to three buyers, at an average nominal price of US$3.88/Mscf in 2020. For the purposes of the economic evaluation, an oil price of US$59.3/bbl is assumed in 2020. All other relevant assumptions, including price forecasts, are provided in the attached 2019 Nigeria CPR.

Figure 20, NPV10 for Reserves net to Savannah (as at 1 November 2019)

	NPV10 (US$MM) of Reserves net to Savannah		
	1P	2P	3P
Uquo	139.2	227.7	322.1
Stubb Creek	38.1	56.7	72.0
Total	177.2	284.4	394.1

Source: Adapted from the Nigeria CPR

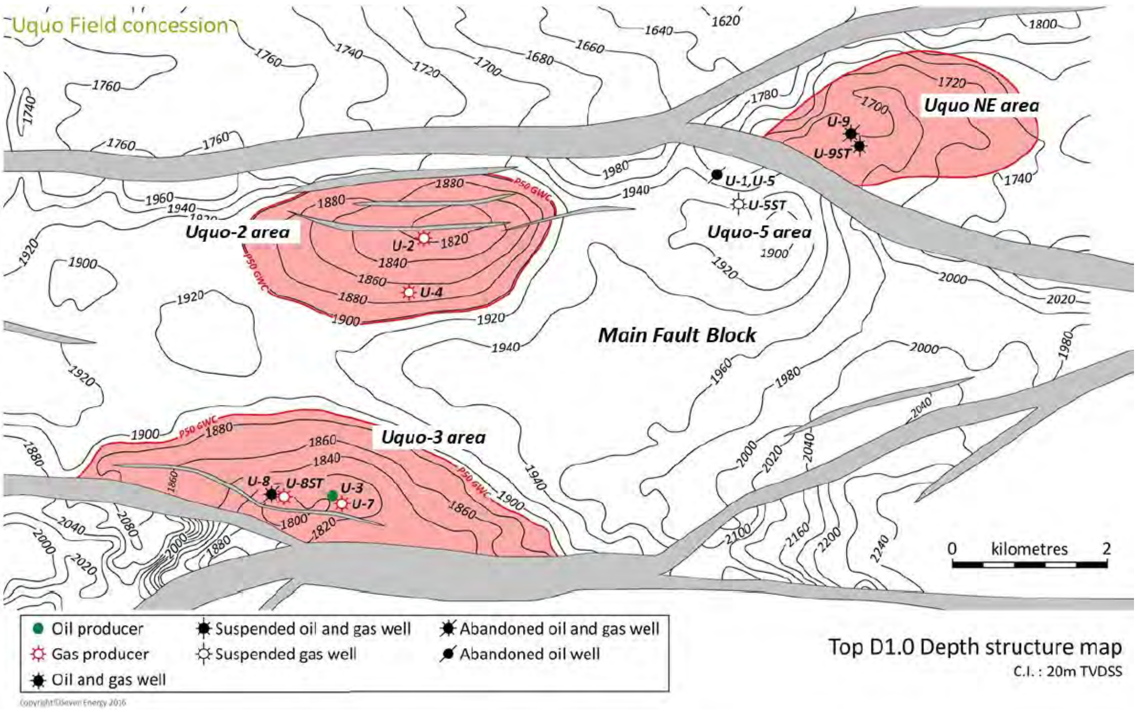
4. Uquo Marginal Field

The Uquo Field was designated as "Marginal" at a time when the primary E&P objective in the Niger Delta was oil, but it has actually proved to be quite a significant gas field, with some associated oil production. It is located onshore in OML 13 within Akwa Ibom State, South East Niger Delta, c. 10 km from QIT. The Uquo Field is contained within a licence area which now encompasses both the field itself and a number of undeveloped Discoveries and Prospects, which provide significant upside potential.

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, at depths between 6,800 ft (2,100 m) and 8,000 ft (2,400 m). Appraisal drilling in the 1970s encountered mainly gas, although one well was subsequently completed as an oil producer. The Uquo Field was originally 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 license area is covered by a high quality 3D seismic survey, acquired in 2006-2007.

Uquo 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.

Figure 21, Uquo Field Depth Structure



Source: Nigeria CPR

The gas and oil accumulations proven at the 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 22).

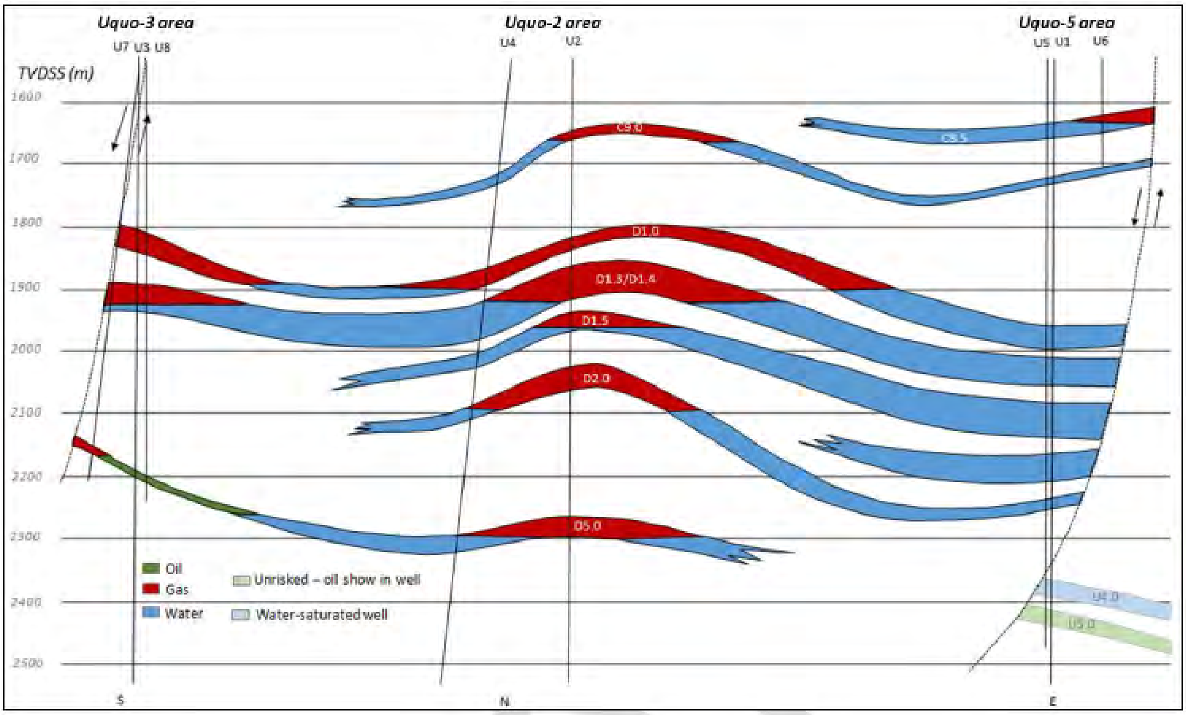
- *Uquo-2 area.* This dip closed rollover has gas proven in five of the Agbada D sands, with GIIP of c. 475 Bscf (Best Estimate), at depths between 5,900 ft (1,800 m) and 7,550 ft (2,300 m). There are two wells on production (Uquo-2 and Uquo-4) from the D2.0 and D1.0 sands respectively. Upside exists 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 D1.0 and D1.3/D1.4 sands between c. 5,900 ft (1,800 m) and 6,100 ft (1,900 m) and oil/gas in the deeper D5 below c. 6,900 ft (2,100 m). The Best Estimate GIIP is 239 Bscf (mainly in D1.0). Two gas wells are currently producing from the D1.0 sand (Uquo-7 and -8ST). Upside potential exists in associated extensions to the west.

- *Uquo-5 area.* This is a small dip-closed rollover in the hanging wall of an east-west 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. 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 were discovered in the Uquo-9/9ST well. The Best Estimate GIIP on the license is around 140 Bscf (in the Agbada C6.0 at around 4,200 ft (1,300 m), and D1 sands).

Figure 22, Uquo Field Depth Structure



Source: Nigeria CPR

The gas sands at Uquo Field are estimated to have a total GIIP in excess of 800 Bscf (Best Case), and full development is thought to require seven wells; four existing wells (with one work-over) and four new wells. Based on these assumptions, an independent assessment estimates around 500 Bscf could be recovered in the Proven plus Probable case, of which about 400 Bscf are attributable to Savannah's interest.

2019 gas production from the four producing wells averaged 90 MMscfpd with peak production of 140 MMscfpd and cumulative production of 138 Bscf of gas (to 31 October 2019) since first gas in Q4 2013.

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 23, Uquo Field – Gas Reserves and Contingent Resources (as at 1 November 2019)

	Gross on Licence			*Net Attributable*		
Gas (Bscf)	1P/1C	2P/2C	3P/3C	1P/1C	2P/2C	3P/3C
Reserves	301.0	500.9	721.7	240.8	400.7	577.4
Contingent Resources	45.0	72.5	115.6	36.0	58.0	92.5

Source: Adapted from the Nigeria CPR

Gas produced from the Uquo Field is processed through the Uquo CPF, which is owned by Accugas Limited A detailed description of the assets held by Accugas Limited are contained in paragraph 6 of this Part 4.

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. Current liquids facility capacity at the field is approximately 2,000 bopd.

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 24). 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 de-risk these prospects. Together they provide a significant potential upside for the field, with over 800 Bscf of un-risked potential GIIP.

Figure 24, Uquo Field – Exploration prospects

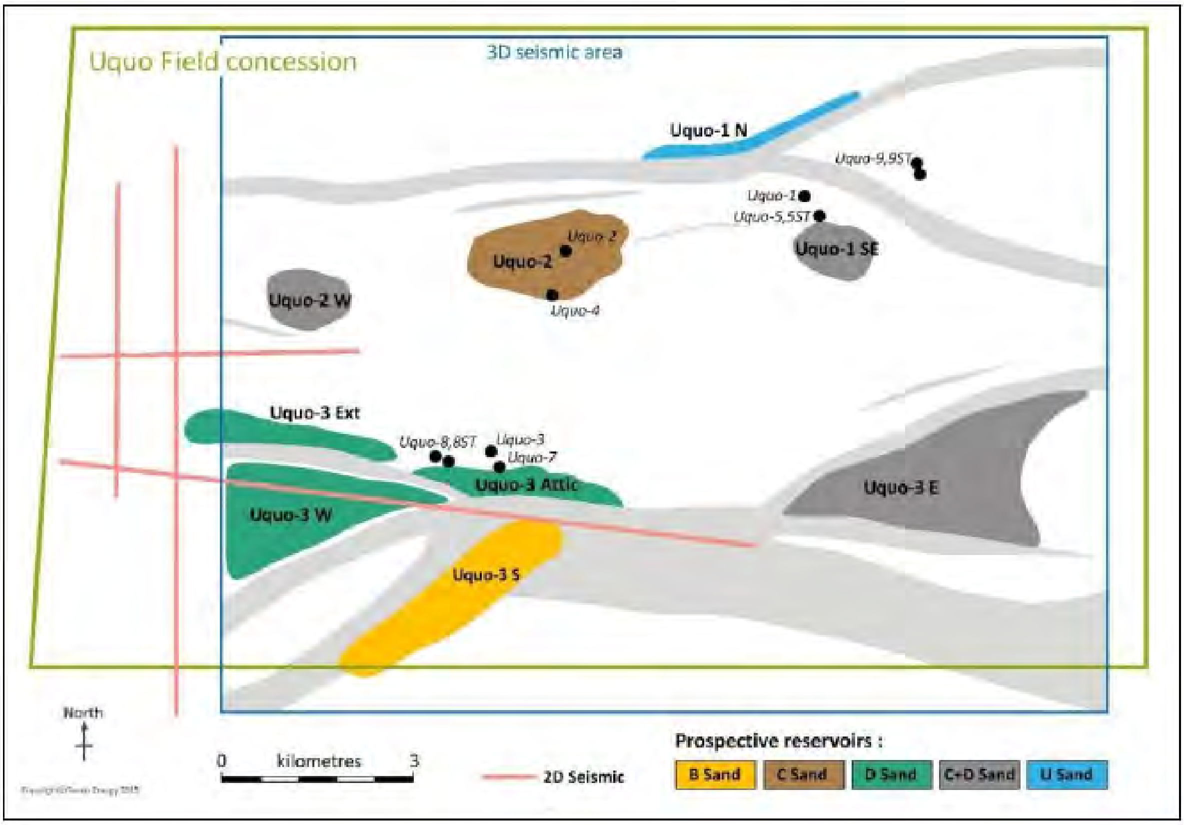
Gross GIIP (Bscf)	*Low*	*Best*	*High*	*Chance of Success* [1]
Uquo 1SE	55.7	84.8	139.9	0.50
Uquo 2	13.6	25.4	51.0	0.73
Uquo 2W	71.3	88.4	103.7	0.57
Uquo 3E Licence	151.5	221.7	335.7	0.35
Uquo 3S Licence	114.8	154.3	200.1	0.66
Uquo 3W Licence	72.5	115.2	204.1	0.18
Uquo 3 Extension	10.2	15.1	22.6	0.14
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 [2]	558.0	826.8	1,228.8	

1 "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

2 Arithmetic sum

Source: Adapted from the Nigeria CPR

Figure 25, Uquo Marginal Field Area – Exploration Prospects



Source: Nigeria CPR

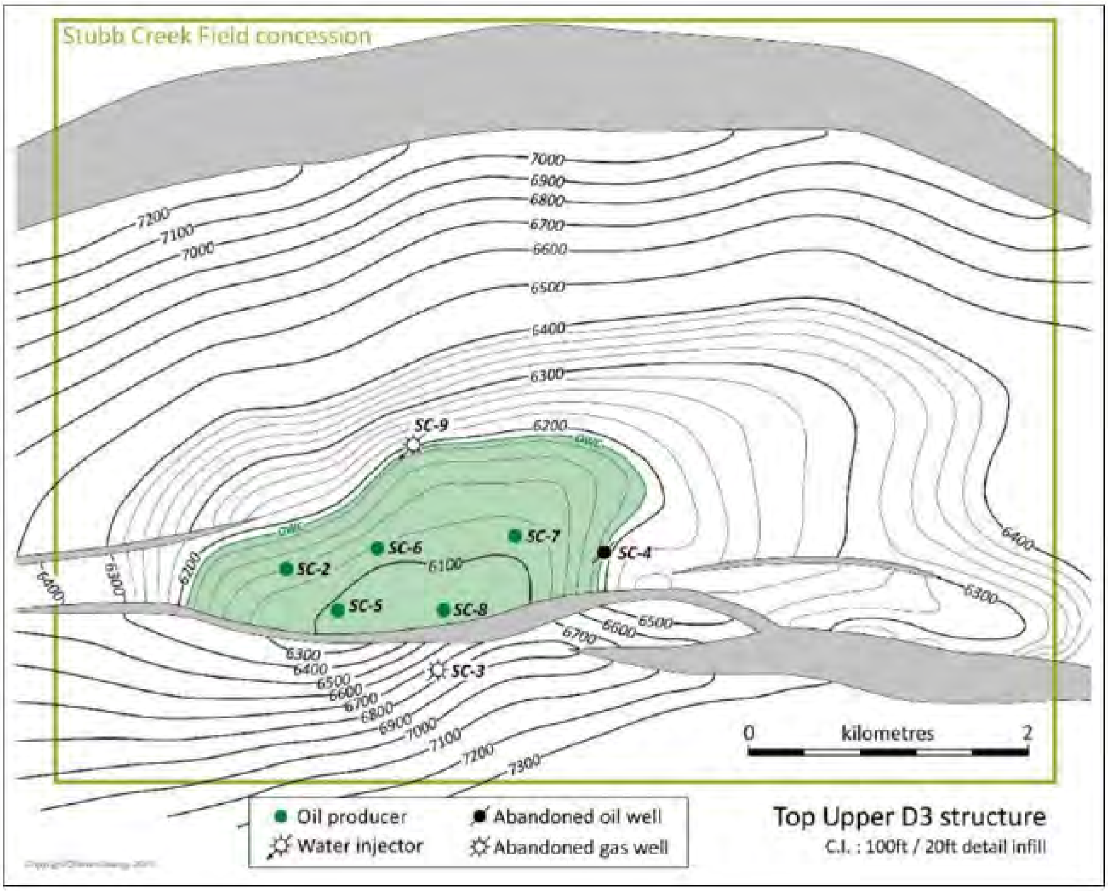
5. Stubb Creek Marginal Field

The Stubb Creek Field lies within the area OPL 276, formerly OML 14, near the mouth of the Cross River and approximately 20 km east of the Uquo Field. Savannah holds an indirect 51 per cent. operated interest in the Stubb Creek Field through its 100 per cent. economic ownership of the field operator, Universal, which holds a 51 per cent. interest. The remaining 49 per cent. interest is held by Sinopec.

Discovered by Shell in 1971, Stubb Creek was awarded to Universal as a Marginal field in 2003. Seven Energy acquired its interest in 2009 and 2010 through a two-stage acquisition of a 62.5 per cent. shareholding in Universal. The Field was brought into commercial production in 2015 using the Stubb Creek EPF, which is capable of processing oil at a gross rate of around 3,000 bopd. Oil is exported via the FUN Manifold to the QIT.

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 east-west oriented rollover anticline structure in the downthrown hanging wall of a prominent east-west fault. A total of nine wells have been drilled in the 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. 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.

Figure 26, Stubb Creek Field outline – D3 depth structure



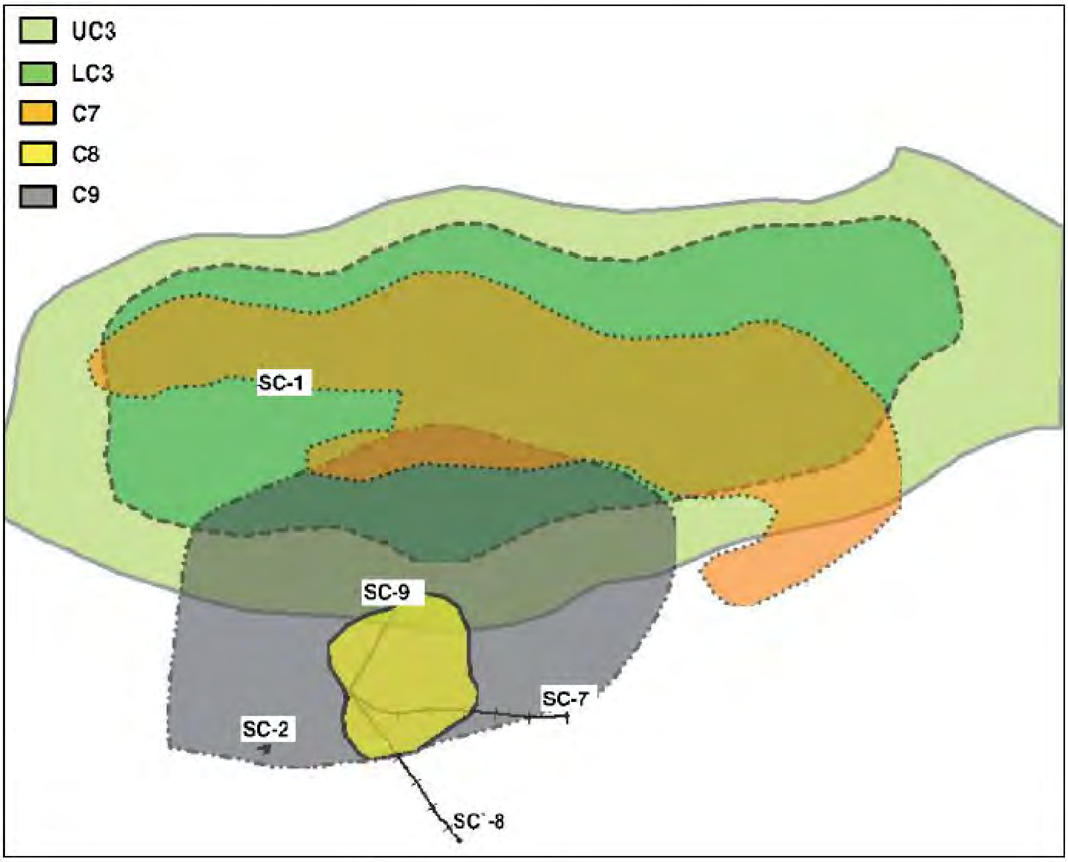
Source: Nigeria CPR

The focus of appraisal and development to date at Stubb Creek Field has been the oil, located in the deeper sands on the south side of the field. Production started in February 2015, and 3.7 MMstb have been produced to date (to end October 2019). However, since the involvement of the Seven Group in the asset, attention has also turned to the large but un-appraised gas resources in the shallower section.

- *D Sands*. The deeper D sand section of the Agbada formation forms a three-way dip and fault bounded closure adjacent to a complex series of east-west normal faults on the south side of the field area (as is illustrated in Figure 26). Oil is found in the Upper D3 sands, at depths below 6,050 ft (1,800 m). A thin oil rim (12 ft) also occurs at the base of the deepest overlying C9 gas sand at around 4,700 ftss (1,400 m), 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 3,600 ft (1,100 m) to 5,000 ft (1,500 m), shallower than the oil accumulations in the D sands. Gas occurs in the Upper and Lower C3, C7, C8 and C9 sands (see Figure 27). 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.

Figure 27, Stubb Creek Field – C sand gas resource outline



Source: Nigeria CPR

Oil Reserves have been assigned only to the Upper D3 sand (Figure 26). These have been developed with five wells (SC-2, -5, -6, -7 and -8), of which three are currently on production at a combined rate of around 2,500 bopd (2019), with cumulative production to date of 3.7 MMstb. The SC-2 and -5 wells are currently shut-in, but are ready to go on stream once planned de-bottlenecking of facilities allows production to increase to c. 5,000 bopd. 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, should be sufficient to fully develop the Upper D3 oil pool with about a 50 per cent. recovery factor. Gross remaining 2P reserves are 15.4 MMstb, of which 3.7 MMstb are attributable to Savannah’s interest. There are no oil Contingent Resources recognised.

Figure 28, Stubb Creek Field – Oil & Condensate Reserves and Contingent Resources (as at 1 November 2019)

	Gross on Licence			*Net Attributable*		
Oil (MMstb)	1P/1C	2P/2C	3P/3C	1P/1C	2P/2C	3P/3C
Reserves	7.9	15.4	25.0	1.7	3.7	6.4
Contingent Resources	–	–	–	–	–	–

Source: Adapted from the Nigeria CPR

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 293.7 Bscf are attributable to the Savannah interest.

Figure 29, Stubb Creek Field – Gas Reserves and Contingent Resources (as at 1 November 2019)

	Gross on Licence			*Net Attributable*		
Gas (Bscf)	1P/1C	2P/2C	3P/3C	1P/1C	2P/2C	3P/3C
Reserves	–	–	–	–	–	–
Contingent Resources	364.9	515.3	680.3	208.0	293.7	387.8

Source: Adapted from the Nigeria CPR

It is anticipated that the existing Stubb Creek EPF will be debottlenecked in 2021, to increase oil production capacity to around 5,000 bopd. The total capital investment anticipated for this project, involving bringing 2 existing wells into production and drilling a downdip water disposal well, is US$28 million.

Development of the contingent gas resources at Stubb Creek Field is anticipated to begin in 2030, with up to four new gas wells drilled over a 5-year period at an estimated gross cost of US$108 million. Production would be tied back to the Uquo CPF via a new 31 km pipeline, allowing gas to be sold to the Accugas Midstream Business, supplementing the gas produced from the Uquo Field.

6. Accugas Midstream Business

Savannah holds an indirect 80 per cent. interest in Accugas Limited, the midstream business which 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 Savannah expects additional high value incremental demand from regional industrial customers and is in a number of discussions in this regard.

The Accugas Midstream Business comprises:

- 200 MMscfpd Uquo CPF;
- c. 260 km network of gas pipelines; and
- c. 600 MMscfpd gas distribution capacity.

Accugas Limited buys gas from its sole current supplier, SUGL, under an upstream GSA at a price of US$1.31/Mscf for 2020 on an unindexed basis, and sells this gas to three separate customers at a weighted average nominal price of US$3.88/Mscf for 2020.

First commercial gas delivery from the Uquo CPF began in January 2014 to the 190 MW Ibom power station. At present, Accugas Limited has three long-term downstream 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 in Figure 30 below.

The Uquo CPF consists of two identical gas processing trains, each with a nameplate capacity to process up to 100 MMscfpd.

Gas Sales Agreement

There are currently three long-term downstream GSAs in place and are currently taking deliveries.

Figure 30, Accugas Summary of Key Gas Sales Agreements

	Calabar NIPP	*Unicem*	*Ibom Power*
Description	Nigerian State Power Plant	Lafarge Cement Plant	Nigerian State Power Plant
Contract End	Sept 2037	Dec 2031	Dec 2023
Daily Contract Quantity ("DCQ")	131.0 MMscfpd	38.7 MMscfpd	19.7MMscfpd
Take-or-Pay	80%	80%	80%

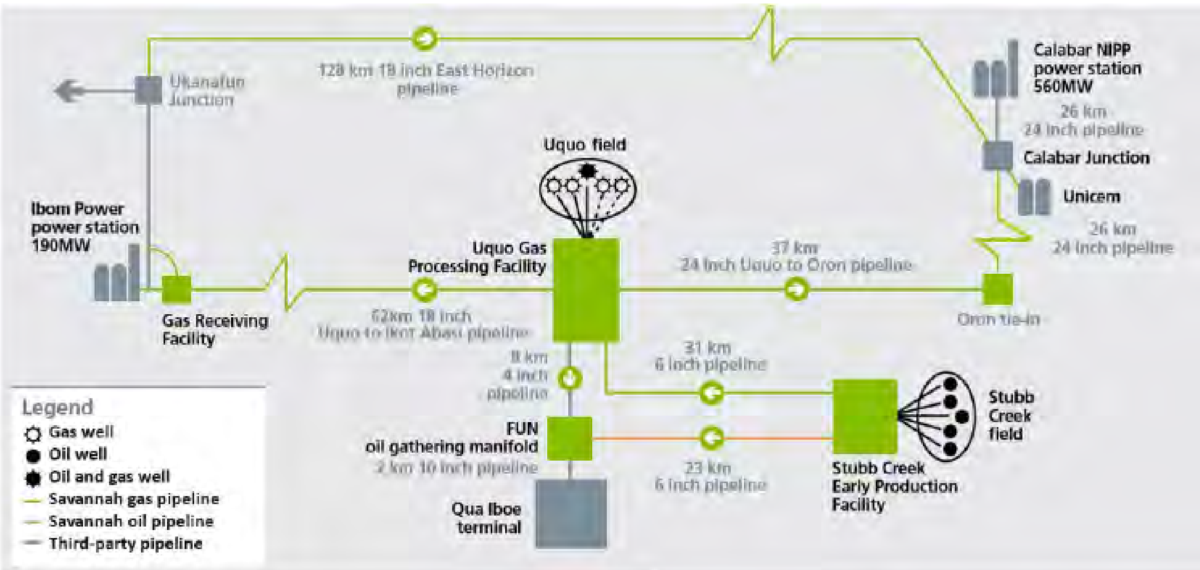
Accugas Limited's historic focus has primarily been on high volume, but lower price power station customers, which sell their electricity into the regulated Nigerian distribution network. These customers underpinned the contracted forward gas sales which were required to justify the initial capital investment into the Accugas' business infrastructure. Going forward, Accugas Limited's business development opportunities are expected to be focused on lower volume 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).

Infrastructure

The key gas pipelines in the Accugas Limited network include (but are not limited to):

- 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 Creek Town (the delivery point for the Calabar GSA), construction completed in 2016
- East Horizon gas pipeline (128 km, 18-inch) – acquired in Q1 2014 and delivering gas to Unicem since 2012

Figure 31, Accugas Midstream Business Infrastructure



Source: Nigeria CPR

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 Company 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.

Associated gas from the Stubb Creek field is currently being routed to the Uquo CPF.

Valuation

The Base Case NPV, at 10 per cent. discounting, for the Accugas Midstream Business (and pre any debt charges or repayments) has been determined to be $840.9 million, of which $672.8 million is net to the Savannah 80 per cent. interest. The valuation reflects the Take or Pay provisions of existing GSAs, supplied from Uquo gas field and later by gas development at the Stubb Creek Field.

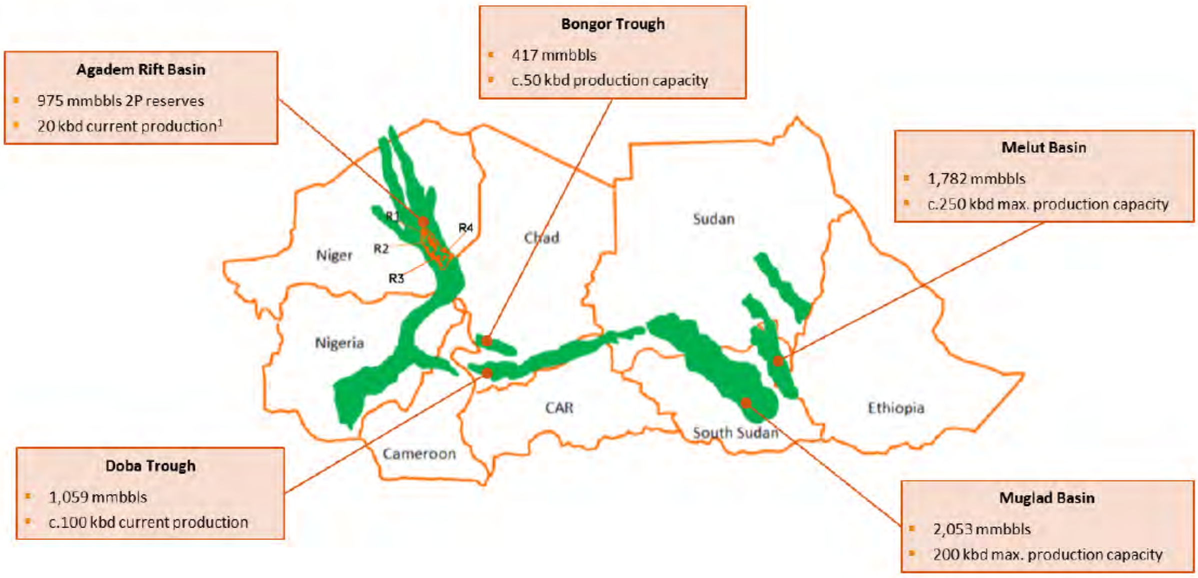
PART 5

NIGERIEN ASSET OVERVIEW

The Company's Nigerien assets, which comprise the R1/R2 PSC (which is to be replaced by the new R1/R2/R4 PSC subject to, inter alia, Council of Ministers approval for the new PSC area, as discussed earlier in this document) and the R3/R4 PSC, are two large, onshore PSCs on which the Company has been conducting a highly successful exploration programme resulting in the drilling of five oil discoveries within the R3/R4 PSC in 2018.

The Savannah PSCs 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 6 billion bbls of oil discovered to date. Topography in the ARB is relatively flat, with no significant mobile sand dunes. The Savannah PSCs are located c. 200km away from the nearest major population centers.

Figure 32, Central African Rift System – Regional Discoveries



Source: Niger CPR

The Savannah PSCs represent c. 50 per cent. of the ARB, and of the original Agadem PSC Area which was compulsorily relinquished by CNPC in July 2013 and subsequently acquired by Savannah over the course of 2014 and 2015.

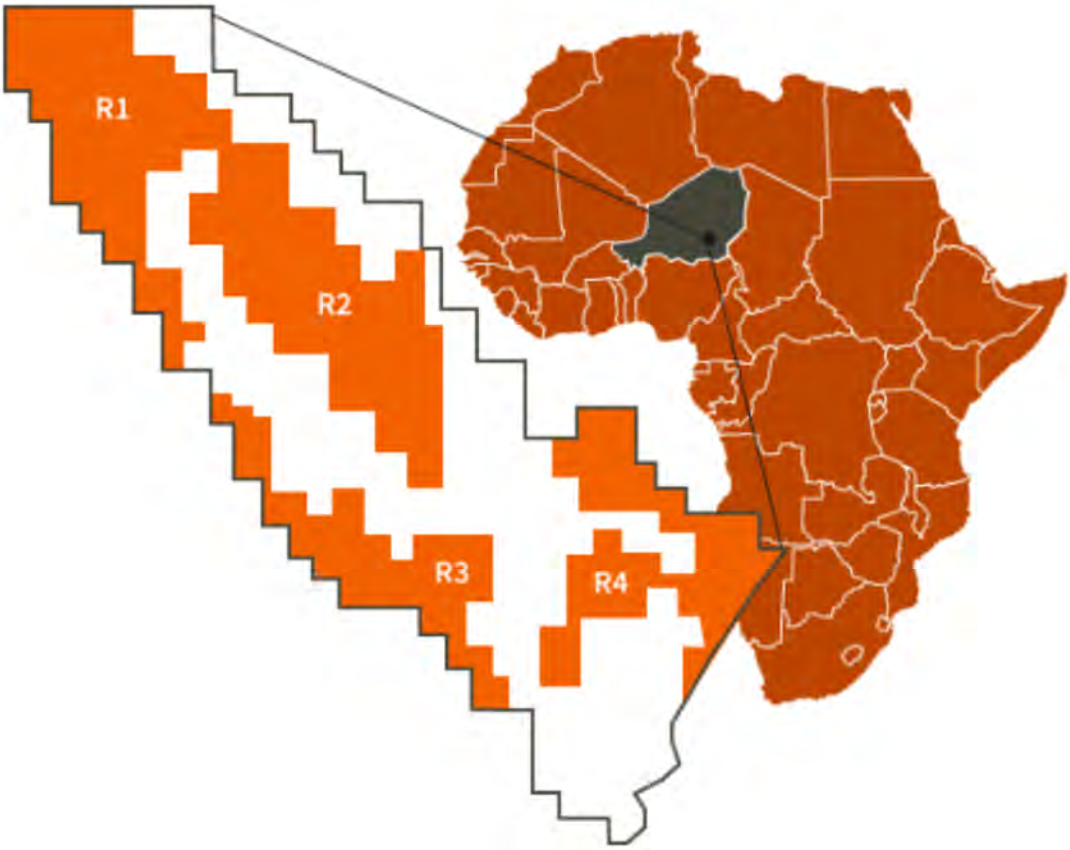
CNPC's involvement in Agadem has been transformational for the upstream industry in Niger, markedly increasing the success rate in the area, with 110 discoveries from 137 exploration wells, establishing 2P reserves of c. 1 billion bbls through the application of 3D seismic technology coupled with an efficient and effective operating model. Following the construction of a 20,000 bopd refinery at Zinder and a 463 km pipeline linking the refinery to Agadem, first oil from Agadem was established in 2011, only three years after licence acquisition.

1. Licence Interests

- *R1/R2/R4 PSC:* The new R1/R2/R4 PSC Area covers an area of approximately 11,394km^2.

- *R3/R4 PSC:* The smaller of the two PSC's covers an area of 2,261 km^2 and has been the initial focus of the Company's exploration efforts with an 806 km^2 3D seismic survey acquired and processed in 2016/2017 and five successful exploration wells drilled in 2018.

Figure 33, Location of the Savannah PSCs



Source: Niger CPR

2. Petroleum Geology of the Agadem Rift Basin

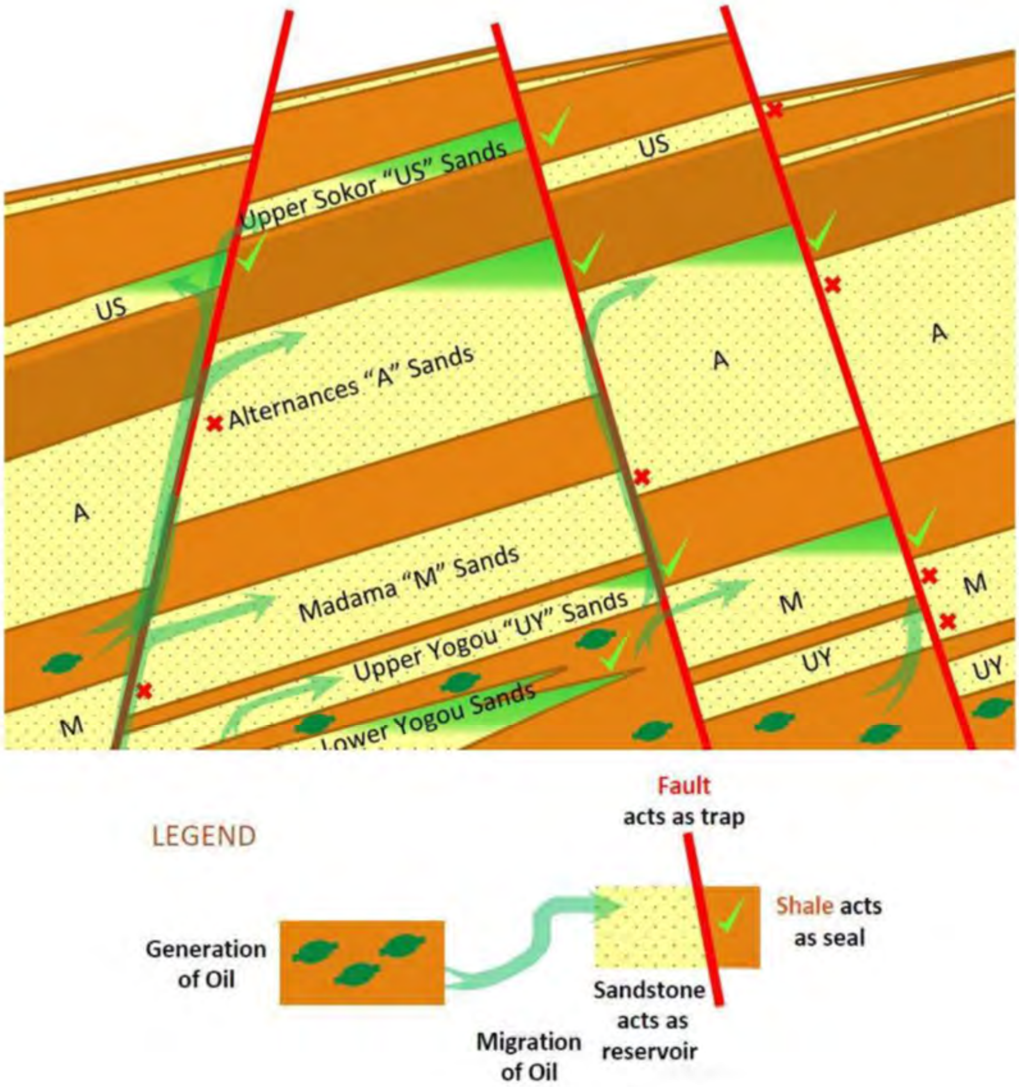
The ARB sedimentary fill comprises up to 5 km of sands and shales, of Late Cretaceous to Tertiary age. These were deposited into the deepening rift from surrounding uplifted highlands, via a series of large rivers draining a predominantly arid hinterland, and with occasional marine incursions from the south. The deepest, Cretaceous section is currently "mature" for oil and gas, and is thought to be the source of hydrocarbons trapped in the over-lying Eocene and younger section – mainly in traps formed by the rift faulting which brings sealing shale lithologies against sandstone reservoir rocks, as shown in Figure 34 below.

Savannah recognises oil potential in a number of sequences within the ARB:

- *Upper Sokor Formation:* Oil has been recovered from at least 6 wells in the ARB from this shallow section, at depths less than 1,600 meters, and other shows are reported. Although this is shallow for a conventional oil exploration target, there are no signs of biodegradation reported, and sands here may be a viable secondary target.
- *Sokor Alternances Formation:* This has been the principal focus of exploration in the ARB to date; all of the Savannah discoveries are from within this sequence, as are a high proportion of the discoveries made by CNPC.
- *Madama Formation:* This unit, underlying the Sokor Alternances, has a distinctive seismic character seen across the ARB. It is not currently viewed as an exploration target, and many of the exploration wells are terminated within the Madama.
- *Upper Yogou Formation:* This Upper Cretaceous unit is thought to be the principal oil source in the ARB. It is mature for oil in the central part of the rift. Good porosity sandstones occur, and the unit is a viable exploration target on the Savannah acreage, with prospective resources recognised by CGG underlying the Eocene discoveries and prospects. Some larger, deep structures occur which are not reflected in the Eocene, and may form interesting exploration targets, and some encouraging test results are reported from CNPC wells.

- *Lower Yogou & Donga Formations:* Various exploration ideas are being investigated for this deep, and also, potentially, also gas-mature part of the section, although no prospects have been identified to date.

Figure 34, Cartoon section across the ARB, showing main hydrocarbon plays



Source: 2017 Niger CPR

3. Resources

Contingent Resources

Each of the five wells drilled by Savannah in 2018 can be classified as 'Discoveries' under the Petroleum Resource Management System (PRMS) 2018 definitions, and for which Contingent Resource volumes can be estimated, as determined by CGG in the Niger CPR. These amount to over 33 MMstb net attributable to Savannah in the 2C, mid case.

Figure 35, Contingent Resource estimates

Discovery	Gross on Licence 1C	2C	3C	Net Attributable 1C	2C	3C	Chance of Development	Operator
Amdigh	7.2	18.4	83.9	6.8	17.5	79.7	High	Savannah
Eridal	4.3	6.2	8.5	4.0	5.9	8.1	High	Savannah
Bushiya	3.3	6.2	12.9	3.2	5.9	12.3	High	Savannah
Kunama	1.8	4.2	9.3	1.8	4.0	8.8	High	Savannah
Total MMstb	16.7	35.0	114.6	15.8	33.3	109.1		
Zomo	0.0	0.2	0.0		0.2		Medium	Savannah

Note: Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

Source: Adapted from the Niger CPR

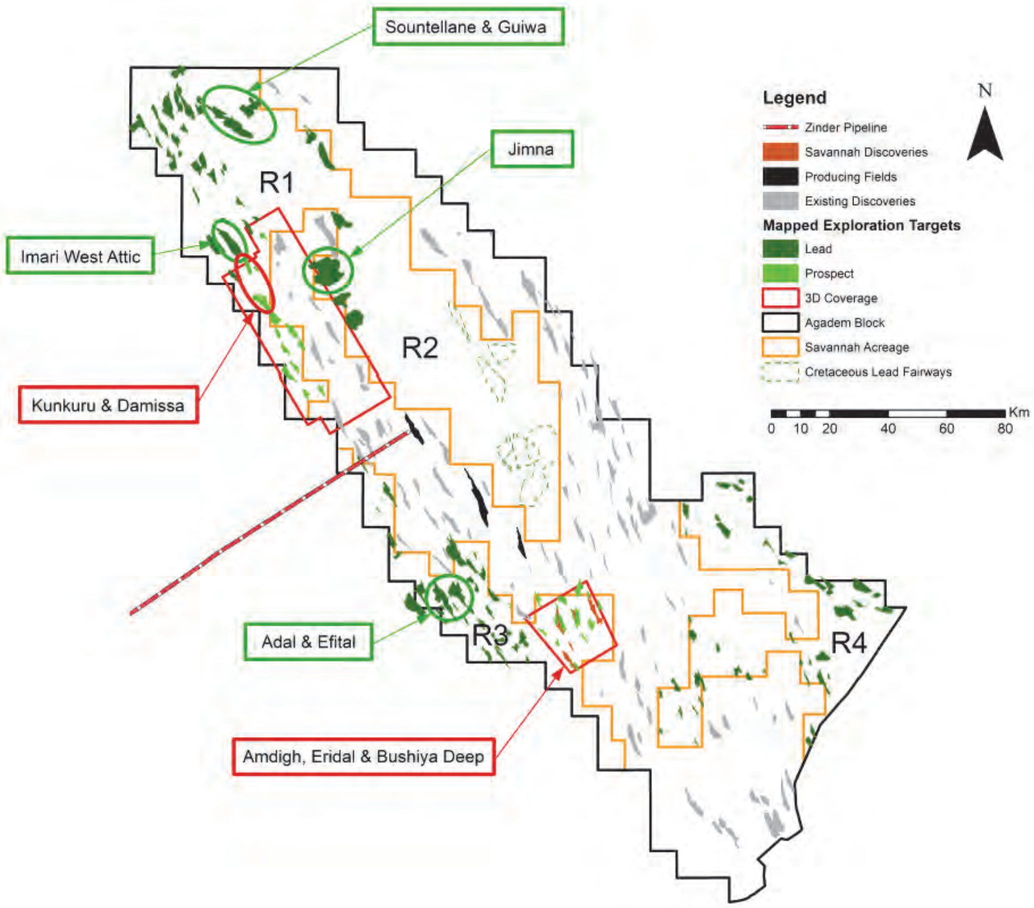
Four of these discoveries are assessed by CGG as having a high probability of commercial development, allowing relatively near-term future conversion of these volumes to Reserves under PRMS guidelines. Evaluation of the Zomo discovery is preliminary, pending further seismic evaluation, and the indicative resources shown are excluded from the total.

Prospective Resources

CGG recognise a total of eleven exploration Prospects and Leads, for which Prospective Resource estimations have been made (Figures 37 and 38). Five of these are located on the R3/R4 PSC, with an aggregate gross Best Estimate resource potential of c. 90 MMstb (Figure 37) and assessed Chance of Success of 25 per cent. to 75 per cent. Three of these are deep exploration targets in the Cretaceous Yogou formation below the shallower discoveries at Bushiya, Amdigh and Eridal. Two further undrilled Leads are identified on the western edge of the R3/R4 PSC, with prospectivity in the Sokor as well as the deeper Yogou formation.

A further six undrilled exploration prospects and leads have been assessed by CGG in the R1/2/4 PSC, within the R1/R2 area to the north west of the R3/R4 PSC. These all have exploration potential throughout the section and have a larger aggregate gross resource potential of 270 MMstb (Best Estimate – Figure 38). Two of these features, Kunkuru and Damissa, are covered by 3D seismic and are thought to have a high chance of exploration success (>75 per cent.). The other four features are also large (30 – 80 MMstb) but are currently regarded as medium or high risk (most <25 per cent. chance of exploration success).

Figure 36, Map showing Prospects and Leads assessed by CGG



Source: Niger CPR

Figure 37, Prospective Resources estimates, R3 portion of the R3/R4 PSC

	Gross on Licence			*Net Attributable*			*Chance of Success*	*Operator*
Prospect/ Lead	*Low*	*Best Est.*	*High*	*Low*	*Best Est.*	*High*		
Bushaya Deep	1.8	7.6	22.5	1.7	7.3	21.3	Medium	Savannah
Amdigh Deep	2.6	10.9	32.7	2.4	10.4	31.0	Medium	Savannah
Eridal Deep	1.7	6.9	20.0	1.6	6.6	19.0	Medium	Savannah
Adal Lead	3.2	20.6	72.6	3.0	19.6	69.0	Medium	Savannah
Efital Lead	8.7	44.0	130.0	8.3	41.8	123.5	Medium	Savannah
Total MMstb	18.0	90.0	277.8	17.0	85.7	263.8		

Note: Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

Source: Adapted from the Niger CPR

Figure 38, Prospective Resources estimates, R1/R2/R4 PSC

Prospect/ Lead	Gross on Licence Low	Best Est.	High	Net Attributable Low	Best Est.	High	Chance of Success	Operator
Damissa	13.2	66.9	188.1	12.5	63.6	178.7	High	Savannah
Kunkuru	1.9	10.4	31.3	1.8	9.9	29.8	High	Savannah
Sountellane	9.4	35.8	108.2	8.9	34.0	102.8	Medium	Savannah
Imari W Attic	8.8	45.4	149.5	8.3	43.1	142.0	Low	Savannah
Guiwa	6.5	30.0	89.8	6.2	28.5	85.3	Low	Savannah
Jimna	17.2	81.5	254.8	16.3	77.4	242.0	Low	Savannah
Total MMstb	57.0	270.0	821.7	54.0	256.5	780.6		

Note: Net Attributable volumes are given pre-Royalties, pre-Taxes and pre-Government share of profit.

Source: Adapted from the Niger CPR

Yet-to-Find

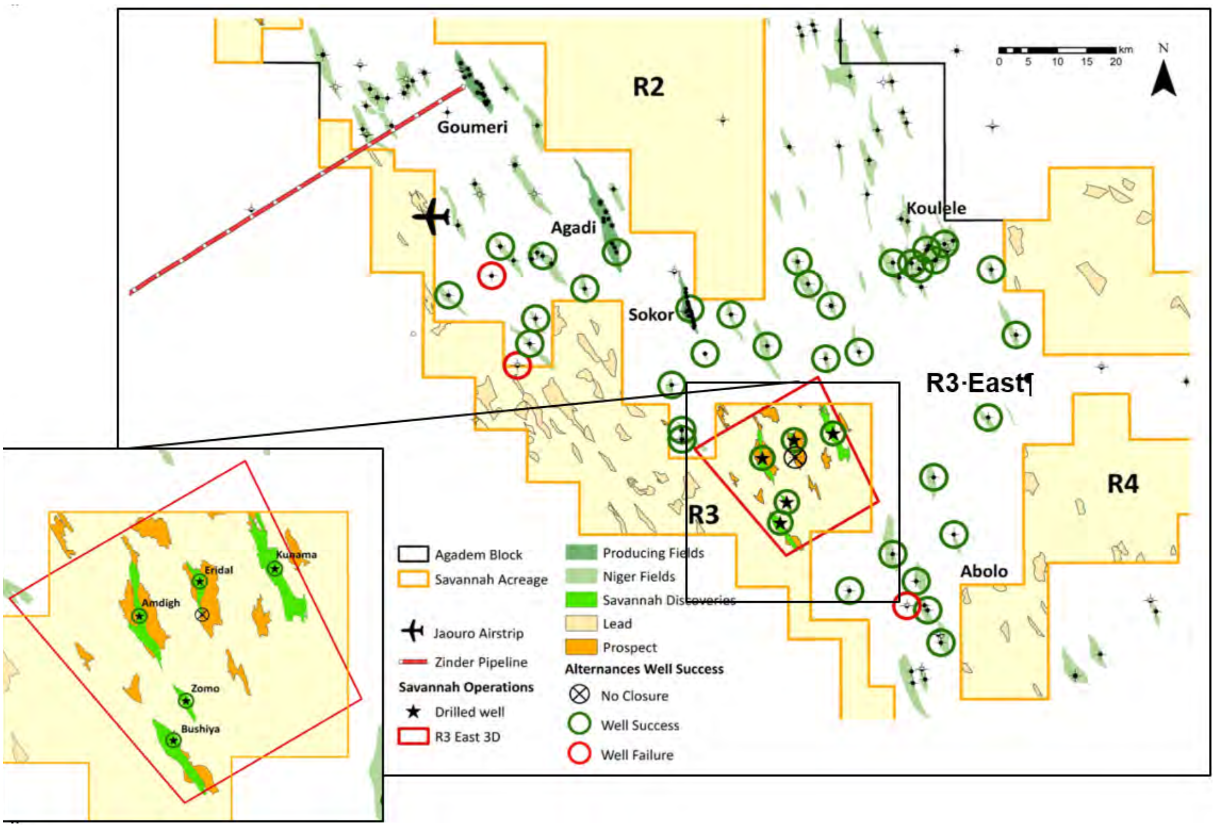
CGG have also undertaken a geological Yet-to-Find analysis, covering all exploration plays across the Savannah acreage, which suggests that on a Best Estimate, risked basis around 2.7 Bnbbls of oil resources could be anticipated.

4. Oil Discoveries

Savannah drilled a total of five exploration wells during the 2018 drilling campaign, resulting in five oil discoveries – an exploration success rate of 100 per cent. – although one of these (Zomo) is very small and has no attributable Resources. The wells were all drilled within the R3 East area of the R3/R4 PSC and are all covered by the R3 East 3D seismic survey acquired by Savannah in 2016/2017. All the discoveries have been made in sandstone reservoirs of the Sokor Alternances formation and have tested oil from the uppermost E1 sequence. In some cases, additional oil zones have been recognised in deeper sequences (E2, E3 and E5).

CGG note that the petrophysical analysis of many of the reservoir sands identified in these discoveries is problematic due to the lack of reliable formation water salinity data. Many of the discovery sands show electrical resistivities which would suggest a high-water saturation – although a combination of mud gas shows while drilling, RFT pressure profiles and direct RFT samples show these to be oil bearing. This analysis will certainly be refined in future as more data is obtained.

Figure 39, Oil Discoveries – R3 East Area

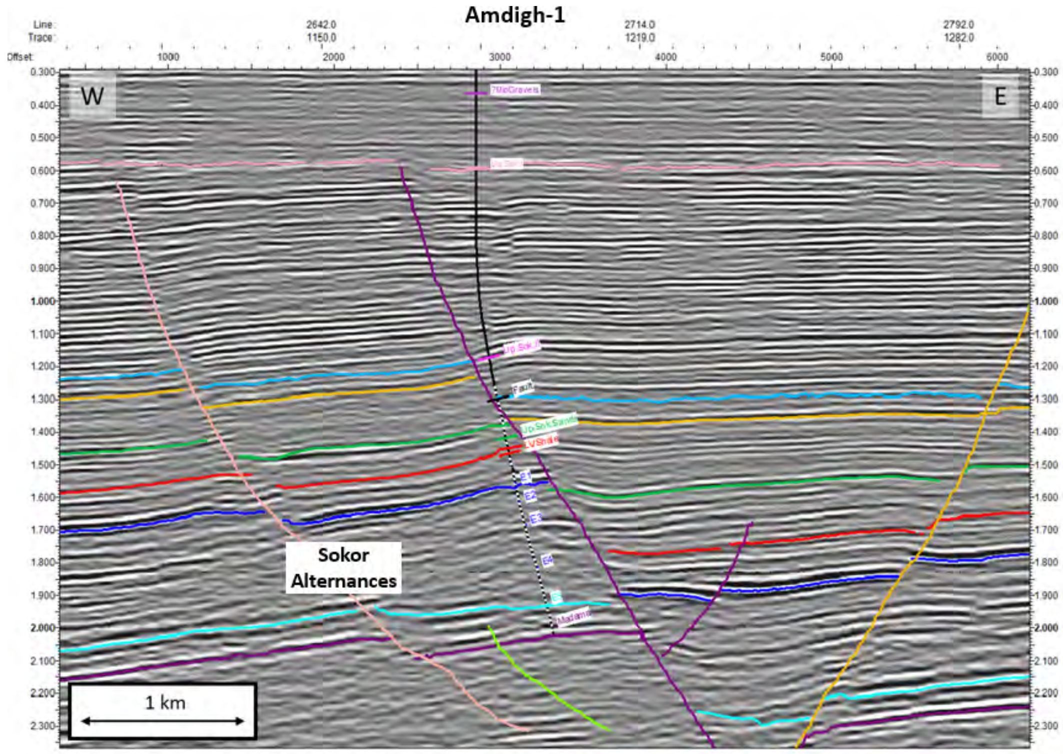


Source: Niger CPR

Amdigh Discovery

The Amdigh-1 well was drilled to 2,469 m on a narrow closure mapped along the crest of a tilted fault block (Figure 40). It is the largest of the Savannah discoveries to date, and with by far the largest upside potential. The well encountered hydrocarbons in three separate sequences (E1, E2 and E3) of the Sokor Alternances formation. The presence of oil (27.5° API) in the E1 and E2 was confirmed by recovery of oil samples and by the interpretation of RFT pressure data.

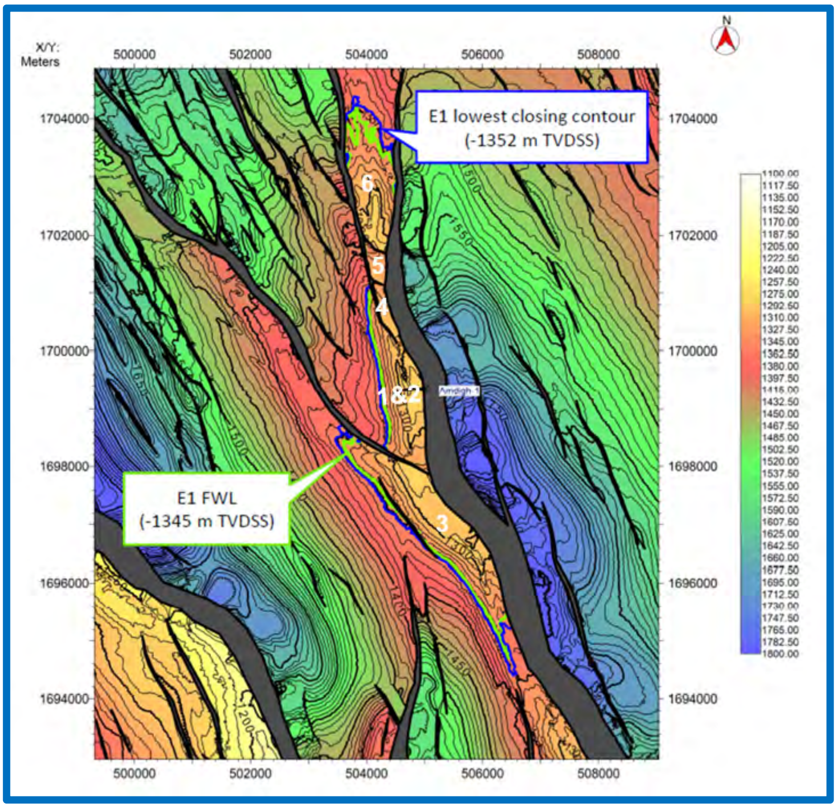
Figure 40, Amdigh-1 Discovery – PSTM seismic section



Source: Niger CPR

The discovery appears to be segmented by a series of cross-cutting faults (as shown in Figure 41), although the drilled central and southern segments are thought to be in pressure communication. The northern extension, however, may be isolated, and CGG have chosen to include this area in only the Upside volumetrics. The range of estimated STOIIP is therefore very wide, from 31 MMstb (P90) to over 250 MMstb (P10), with a P50 mid case of 66 MMstb. Recovery factors in these reservoirs is estimated to be in the range 23 per cent. to 33 per cent., giving a gross 2C Resources of around 18.4 MMstb, of which 17.5 MMstb is attributable to Savannah under the terms of the PSC.

Figure 41, Amdigh Discovery – Top Sokor Alternances, E1 depth structure



Source: Niger CPR

Zomo Discovery

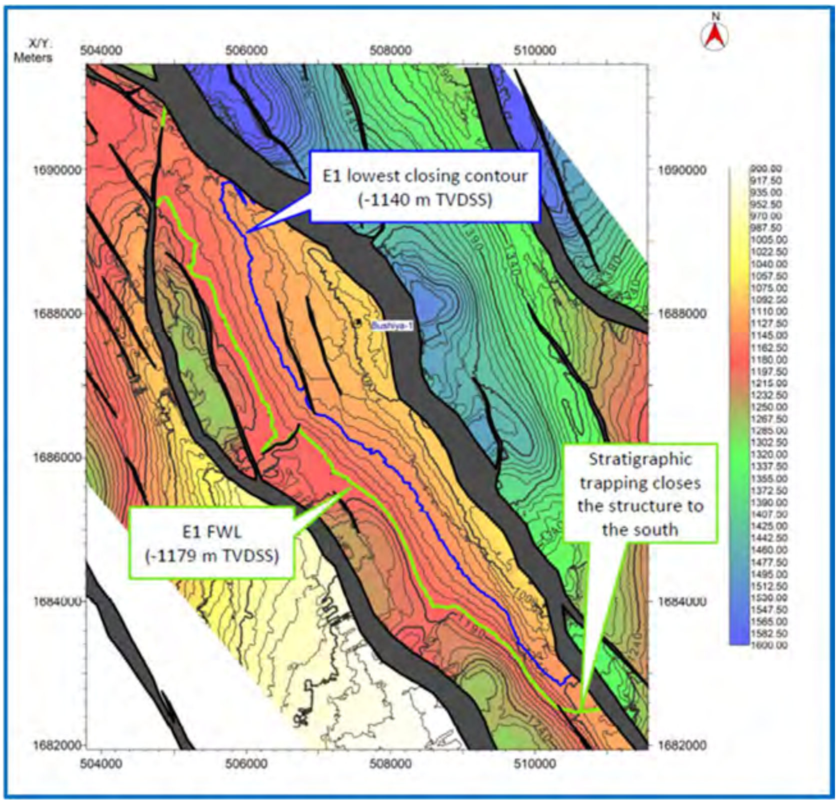
The Zomo-1 well was drilled to 2,499 m depth about 8 km SE of the Amdigh-1 discovery, along the same structural trend, as a potential appraisal of the Amdigh discovery. Oil was again found in the E1 sequence, but at 23.7° API it is somewhat heavier than at Amdigh-1. RFT pressure analysis demonstrates that the Zomo and Amdigh oil columns are actually separate, with Zomo restricted to a very small accumulation at the crest of a small separate closure. Estimated STOIIP is less than 1 MMstb, and no recoverable Resources are currently assigned.

Bushiya Discovery

The Bushiya-1 well was drilled to 2,200 m on a closure mapped along the relatively un-faulted crest of a tilted fault block (Figure 42). The well encountered hydrocarbons at the top of the Sokor Alternances formation, in sequences E1 and E3 (total net pay of 10 m). The E1 column was proven by recovery via RFT of a 24.2°API oil sample, inline with the Amdigh-1 oil analysis from the same interval. The E3 oil column was interpreted from the RFT pressure data.

The estimated STOIIP for Bushiya is smaller than Amdigh, with around 22 MMstb in the P50 case, of which around 6.2 MMstb are recoverable (28 per cent.), with 5.9 MMstb net to Savannah.

Figure 42, Bushiya Discovery– Top Sokor Alternances, E1 depth structure



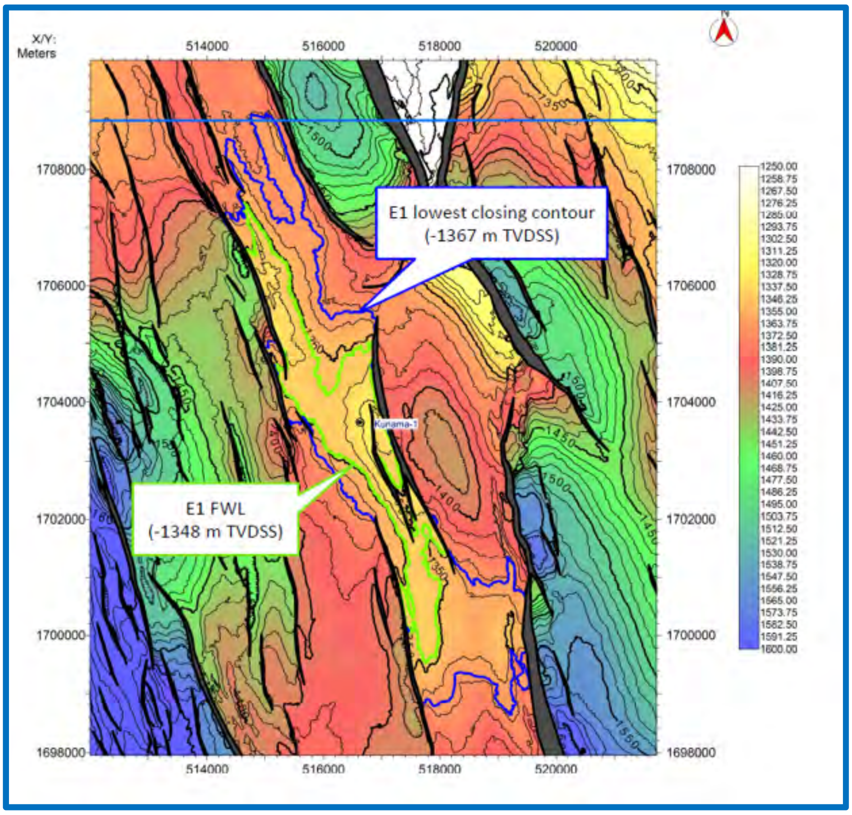
Source: Niger CPR

Kunama Discovery

The Kunama-1 well was drilled to 2,460 meters on the relatively flat crest of a slightly tilted fault block (Figure 42). It is the most "basinal" of the discoveries, lying about 13 km north east of Amdigh. Oil was encountered in the E1 sequence at the top of the Sokor Alternances, proven by RFT recovery of a 28° API oil sample. An additional sample (24.6° API) was recovered from the E5 sequence.

The estimated mid case STOIIP is 15 MMstb of which around 4.2 MMstb are recoverable (28 per cent.), with 4.0 MMstb net to Savannah.

Figure 43, Kunama Discovery– Top Sokor Alternances, E1 depth structure



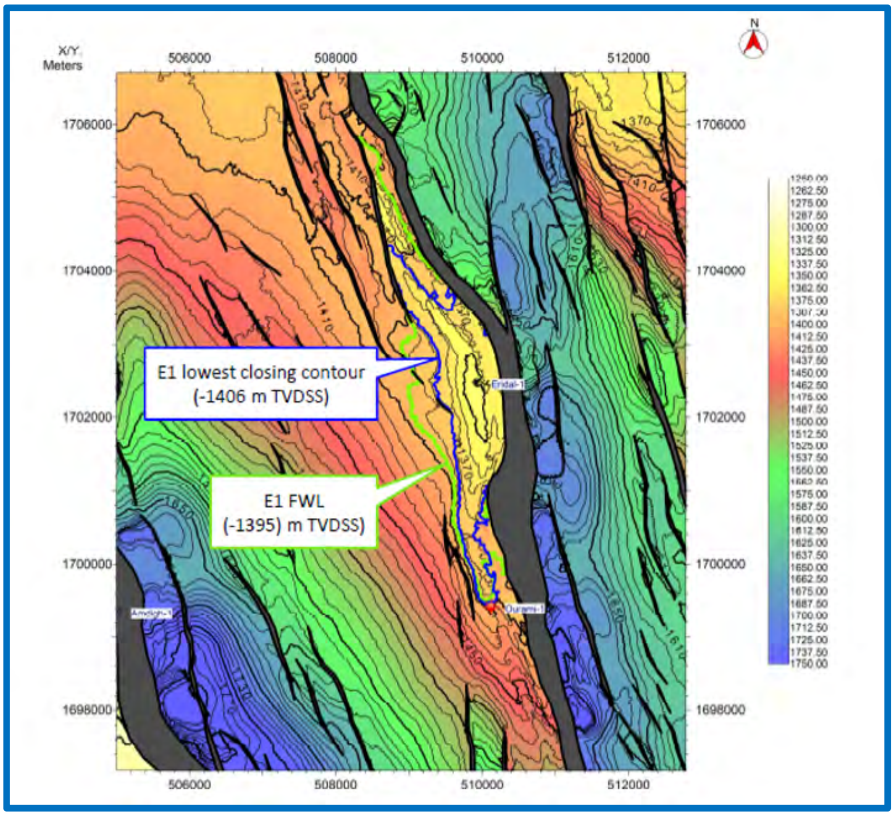
Source: Niger CPR

Eridal Discovery

The Eridal-1 discovery was drilled to 2,542 m on the crest of a tilted fault block (Figure 44), lying between Amdigh and Kunama. A dry hole, Ourami-1 was drilled by CNPC, on the structure about 3 km to the south, but lies outside currently mapped closure. The Eridal-1 well, about 50 m up-dip, encountered oil in the E1 sequence proven by RFT recovery of a 33° API oil sample.

The estimated mid case STOIIP is around 22 MMstb of which 6.2 MMstb are recoverable (28 per cent.), with 5.9 MMstb net to Savannah.

Figure 44, Eridal Discovery– Top Sokor Alternances, E1 depth structure



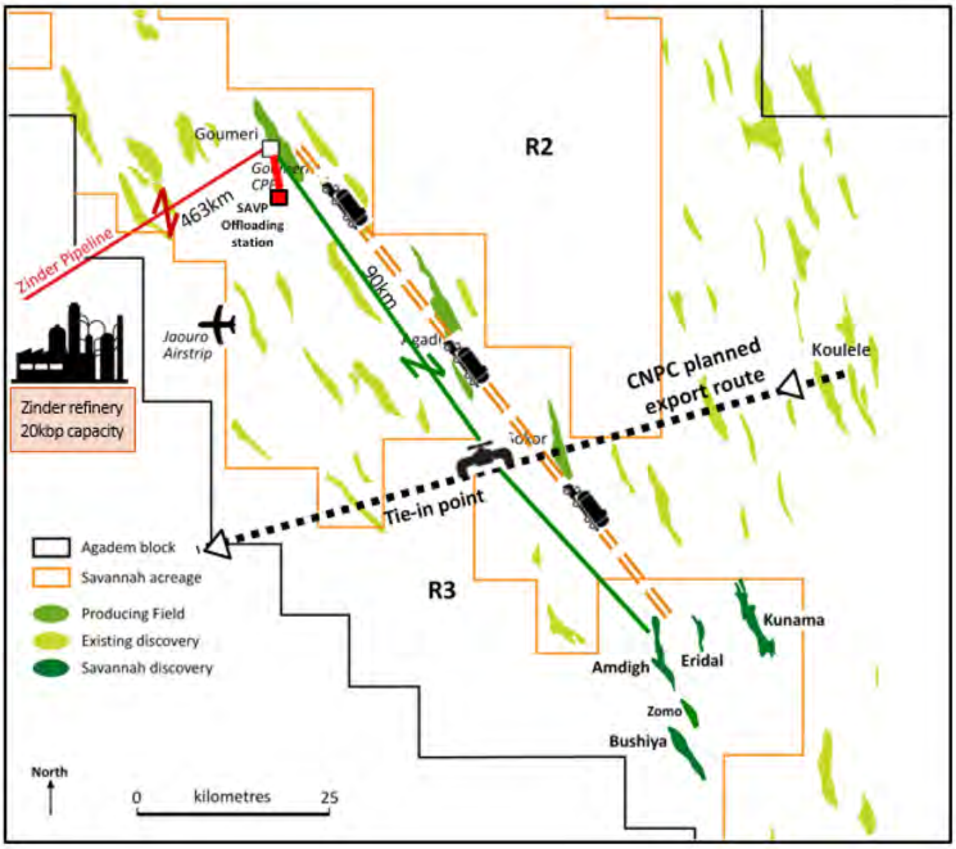
Source: Niger CPR

5. Development Scenarios and Valuation

Savannah has prepared a development scenario for the discoveries drilled in the R3 East area, where the four significant discoveries have around 35 MMstb Gross Contingent Resources (2C). The facilities will be based around the largest discovery, Amdigh:

- *Phase 1:* An Early Production Facility ("**EPF**"), based on production testing the Amdigh-1 and Eridal-1 wells, with oil export by truck to the Goumeri export station 120 km to the north, which is connected by pipeline to the domestic Zinder refinery. EPF facilities would be leased, not owned; capital costs over 2 years would be around US$14 million. Production of 1,500 bopd is anticipated, and subject to market conditions, Savannah expects to launch this project in 2020.
- *Phase 2:* Following successful results from Phase 1 well production, a Central Processing Facility ("**CPF**") is proposed at Amdigh, with the three other discoveries tied back via flowlines and a 90 km export pipeline to Goumeri. Total external funding of around US$57 million is required prior to the project becoming self-funding. Plateau production of 5,000 bopd is envisaged, and the project could recover close to 30 MMstb based on initial reservoir modelling.
- An alternative oil export option may exist in the medium term, as CNPC look to develop the c. 1 Bnbbls of Reserves they have identified across the basin. An ambitious proposal to build a 2,000 km oil export pipeline across Benin to the Atlantic coast is being planned and could be completed as early as 2021. Savannah would have rights of access to this line, and it could provide an attractive alternative in the future.

Figure 45, R3 East Development Plan – Phase 1 and 2



Source: Niger CPR

PART 6A

ACCOUNTANT'S REPORT ON THE HISTORICAL FINANCIAL INFORMATION OF THE TARGET COMPANIES

BDO LLP
55 Baker Street
London
W1U 7EU

30 April 2020

The Directors
Savannah Energy PLC
40 Bank Street
London
E14 5NR

Strand Hanson Limited
26 Mount Row
Mayfair
London
W1K 3SQ

Dear Sirs and Madam

Savannah Energy PLC (the "Company") and its subsidiary undertakings (together, the "Group")

Exoro Holding B.V., Accugas Limited, Seven Uquo Gas Limited and Universal Energy Resources Limited (together, the "Target Companies")

Introduction

We report on the financial information on the Target Companies set out in Part 6B of the admission document. This financial information has been prepared for inclusion in the admission document dated 30 April 2020 of the Company (the "Admission Document") on the basis of the accounting policies set out in note 4 to the financial information.

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.

Responsibilities

The directors of the Company are responsible for preparing the financial information in accordance with the basis of preparation set out in note 2 to the financial information. 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 the 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 Schedule Two of the AIM Rules for Companies, consenting to its inclusion in the 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 significant estimates and judgements 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.

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

Opinion

In our opinion, the financial information gives, for the purposes of the Admission Document, a true and fair view of the state of affairs of the Target Companies as at 31 December 2016, 31 December 2017 and 31 December 2018 and of their results, cash flows, changes in equity for the years then ended in accordance with the basis of preparation set out in note 2 to the financial information.

Declaration

For the purposes of Paragraph (a) of Schedule Two of the AIM Rules for Companies, we are responsible for this report as part of the 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 Admission Document in compliance with Schedule Two of the AIM Rules for Companies.

Yours faithfully

BDO LLP
Chartered Accountants

BDO LLP is a limited liability partnership registered in England and Wales (with registered number OC305127)

PART 6B

HISTORICAL FINANCIAL INFORMATION OF THE TARGET COMPANIES

COMBINED STATEMENTS OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

For the years ended 31 December 2016, 2017 and 2018

	Notes	*2018* *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Revenue	7	93,572	117,884	101,842
Cost of sales	8	(56,951)	(65,759)	(71,908)
Gross profit		36,621	52,125	29,934
Impairment reversal / (expense)	15	138,110	–	(253,494)
Other operating (expenses) / income	9	(1,888)	(2,240)	7,093
Expected credit loss on financial assets	10	(15,543)	–	(1,698)
Administrative expenses	11	(12,284)	(10,868)	(15,052)
Operating profit / (loss)		145,016	39,017	(233,217)
Finance income	12	2,878	4,012	3,781
Finance costs	13	(95,840)	(96,465)	(90,536)
Foreign exchange difference		(6,799)	(5,796)	22,400
Profit / (loss) before taxation		45,255	(59,232)	(297,572)
Tax (expense) / credit	14	(3,111)	63,404	108,664
Profit / (loss) for the year		42,144	4,172	(188,908)
Other Comprehensive Income items that will not be reclassified subsequently to profit or loss				
Defined benefit plan actuarial gain	27	107	–	–
Tax effect of actuarial gains	14	(91)	–	–
Total comprehensive income / (loss) for the year		42,160	4,172	(188,908)
Total comprehensive income / (loss) attributable to:				
Owners of the Target Companies		40,619	743	(187,223)
Non-controlling interests	28	1,541	3,429	(1,685)
		42,160	4,172	(188,908)

COMBINED STATEMENTS OF FINANCIAL POSITION
As at 31 December 2016, 2017 and 2018

	Notes	*2018 US$'000*	*2017 US$'000*	*2016 US$'000*
Non-current assets				
Property, plant and equipment	15	780,547	672,743	698,614
Intangible Assets	16	282	302	351
Deferred tax asset	14	265,236	268,438	205,034
Other non-current assets	18	7,422	3,500	4,417
		1,053,487	944,983	908,416
Current assets				
Inventories	19	2,869	3,175	3,855
Trade and other receivables	20	69,813	87,235	64,227
Inter group loan receivables	29.1	13,003	13,385	15,700
Prepayments	21	3,428	1,616	2,192
Cash and cash equivalents	22	11,652	18,916	10,737
		100,765	124,327	96,711
Total assets		1,154,252	1,069,310	1,005,127
Current liabilities				
Borrowings	24	799,899	765,523	655,095
Trade and other payables	23	546,227	567,983	566,772
Contract liability	26	3,213	3,561	–
Total current liabilities		1,349,339	1,337,067	1,221,867
Non-current liabilities				
Borrowings	24	16,553	24,439	102,356
Contract liability	26	121,846	68,668	62,224
Employee benefits	27	324	–	–
Decommissioning provision	25	67,292	58,816	42,532
Total non-current liabilities		206,015	151,923	207,112
Total liabilities		1,555,354	1,488,990	1,428,979
Net liabilities		(401,102)	(419,680)	(423,852)
Equity				
Share capital		2,665	2,665	2,665
Share premium		24,671	24,671	24,671
Capital contribution		5,431	5,431	5,431
Other reserves		7,200	11,634	18,714
Retained earnings		(455,872)	(477,345)	(485,168)
Equity attributable to owners of the Target Companies		(415,905)	(432,944)	(433,687)
Non-controlling interest		14,803	13,264	9,835
Total equity		(401,102)	(419,680)	(423,852)

COMBINED STATEMENTS OF CHANGES IN INVESTED EQUITY

For the years ended 31 December 2016, 2017 and 2018

	Note	*Attributable to Owners of the Target Companies*							
		Share capital US$'000	*Share premium US$'000*	*Capital Contribution US$'000*	*Other reserves US$'000*	*Retained earnings US$'000*	*Total US$'000*	*Non-Controlling Interest US$'000*	*Total equity US$'000*
At 1 January 2016		2,665	24,671	5,431	37,465	(316,612)	(246,380)	11,520	(234,860)
Unwinding of current year portion of loan discount		–	–	–	(18,751)	18,751	–	–	–
Loss for the year		–	–	–	–	(187,223)	(187,223)	(1,685)	(188,908)
Movement in inter group balance		–	–	–	–	(84)	(84)	–	(84)
At 1 January 2017		2,665	24,671	5,431	18,714	(485,168)	(433,687)	9,835	(423,852)
Unwinding of current year portion of loan discount		–	–	–	(7,080)	7,080	–	–	–
Profit for the year		–	–	–	–	743	743	3,429	4,172
At 31 December 2017 as originally presented		2,665	24,671	5,431	11,634	(477,345)	(432,944)	13,264	(419,680)
Impact of change in accounting policy: Adjustment on initial application of IFRS 9	6.1	–	–	–	–	(23,580)	(23,580)	(2)	(23,582)
At 1 January 2018 – Restated		2,665	24,671	5,431	11,634	(500,925)	(456,524)	13,262	(433,262)
Unwinding of current year portion of loan discount		–	–	–	(4,434)	4,434	–		–
Profit for the year		–	–	–	–	40,609	40,609	1,535	42,144
Other comprehensive income for the year		–	–	–	–	10	10	6	16
At 31 December 2018		2,665	24,671	5,431	7,200	(455,872)	(415,905)	14,803	(401,102)

Capital contribution relates to the difference between the book value and the fair value of the AKIICORP loan obtained by the Target Companies. This amount will be derecognised and reclassified to retained earnings when the loan obligation to AKIICORP is fully extinguished.

Other reserves include merger reserves arising from business combination of Accugas with EHGC in 2017.

COMBINED STATEMENTS OF CASH FLOWS
For the years ended 31 December 2016, 2017 and 2018

	Notes	*2018 US$'000*	*2017 US$'000*	*2016 US$'000*
Profit / (loss) after tax		42,144	4,172	(188,908)
Adjustments for:				
Foreign exchange difference		6,799	5,272	(18,326)
Other income		–	–	(4,079)
Finance income		(2,878)	(4,012)	(6,976)
Finance costs		95,840	96,465	90,506
Depreciation, depletion and amortisation of property, plant and equipment	15 & 16	38,089	41,848	43,404
Impairment charge / (reversal) on property, plant and equipment	15	(138,110)	–	253,494
Adjustments, (Profit) / loss on disposal of property, plant and equipment	15 & 17	4	(5)	2,004
Expected credit loss on trade and other receivables	10	15,543	–	1,698
Provision for asset retirement obligation for the year	25	8,476	16,284	(210)
Income tax expense / (credit)	14	3,111	(63,404)	(108,664)
Defined benefit obligation	27	324	–	–
Adjustment on initial application of IFRS 9		(23,582)		
		45,760	96,620	63,943
Decrease / (increase) in inventory		306	680	391
Decrease / (increase) in trade and other receivables		1,879	(23,008)	80,180
Increase / (decrease) in trade and other payables		(21,756)	1,213	(51,175)
Increase / (decrease) in intergroup loan receivable		382	2,315	–
Increase / (decrease) prepayments		(1,812)	574	–
Increase / (decrease) contract liabilities		52,830	10,005	–
Increase / (decrease) in deferred tax assets		91	–	–
Increase / (decrease) in other non-current assets		(3,922)	917	–
Net cash generated from operating activities		73,758	89,316	93,339
Investing activities				
Purchase of property, plant and equipment		(7,767)	(15,411)	(37,783)
Proceeds from sale of property, plant and equipment		–	12	–
Capex refunds		–	–	452
Loan to ultimate parent		–	–	(15,700)
Loan repayment by ultimate parent		–	–	31,146
Finance income received		2,894	4,012	3,784
Net cash used in investing activities		(4,873)	(11,387)	(18,101)
Financing activities				
Proceeds from borrowings		39,672	45,896	27,000
Repayment of borrowings		(13,182)	(17,228)	(50,195)
Finance costs paid		(102,639)	(98,418)	(50,373)
Net cash used in financing activities		(76,149)	(69,750)	(73,568)
Net (decrease) / increase in cash and cash equivalents		(7,264)	8,179	1,670
Cash and cash equivalents at 1 January		18,916	10,737	9,067
Cash and cash equivalents at 31 December		11,652	18,916	10,737

Notes to the Combined Financial Information

1. General information

This financial information comprises that of four of Seven Energy International Limited's ("SEIL") subsidiaries (collectively the "**Target Companies**"):

- Accugas Limited ("**Accugas**"), which is principally engaged in gas processing, marketing and distribution;
- Seven Uquo Gas Limited ("**SUGL**"), which is principally engaged in exploration, development and production of crude oil and natural gas in Nigeria;
- Universal Energy Resources Limited ("**Universal**" or "**UERL**"), is principally engaged in oil and gas exploration, production and sale; and
- Exoro Holding B.V. ("**Exoro**"), is principally engaged as the holding company of Accugas Limited.

In order to achieve operational efficiencies, the Seven Group undertook an intra-group merger transaction between Accugas Limited and East Horizon Gas Company Limited ("**EHGC**"), which became effective on 31 August 2017. The merger was undertaken by way of a court-sanctioned scheme of merger in which Accugas subsequently remains the surviving entity. EHGC transferred all of its assets, contracts, liabilities and undertakings to Accugas and was dissolved without being wound up, while the enlarged Accugas continues to carry on the combined business activities.

The substance of the merger was that of a re-organisation of entities that were under common control. As such, that combination falls out of the scope of IFRS 3 Business Combinations (Revised 2008). Therefore, the combination has been reflected using the 'predecessor value method' which involves:

- Accounting for assets and liabilities of the acquired business using existing carrying values
- No goodwill is recorded
- The comparative periods have been restated as if the combination had taken place at the beginning of the earliest comparative period presented.

Financial results for 2016 were restated to include both EHGC and Accugas as if the entities had been combined throughout the previous periods and the previous balance sheet dates. The aggregated financial information for that period is based on the restated results.

The Target Companies do not constitute a separate legal group. However, each of the entities comprising the Target Companies were under the common management and control of Seven Energy International Limited throughout the period covered by the financial information.

2. Basis of preparation and measurement

(a) *Statement of Compliance*

The Target Companies do not constitute a separate legal group. Nonetheless, the combined historical financial information of the Target Companies for the three years ended 31 December 2016, 31 December 2017 and 31 December 2018 has been prepared on a basis that combines the results, assets and liabilities of the four entities comprising the Target Companies.

The historical financial information has been prepared in accordance with the requirements of the AIM Rules for Companies and in accordance with this basis of preparation. The basis of preparation describes how the financial information has been prepared in accordance with International Financial Reporting Standards as adopted by the European Union (IFRS as adopted by the EU) except as described below. The financial information has also been prepared in accordance with the relevant requirements of the Companies and Allied Matters Act, CAP C20, LFN 2004 and Financial Reporting Council of Nigeria (FRC) Act No 6, 2011.

IFRS as adopted by the EU does not provide for the preparation of combined financial information, and accordingly in preparing the historical financial information certain accounting conventions commonly used for the preparation of historical financial information for inclusion in investment circulars as described in the Annexure to SIR 2000 (Investment Reporting Standard applicable to public reporting engagements of historical financial information) issued by the UK Auditing Practices Board have been applied. The application of these conventions results in the following material departures from IFRS as adopted by the EU.

- The historical financial information is prepared on a basis which combines the results, assets and liabilities of all entities making up the Target Companies, even though such entities did not historically form a legal group, and therefore does not comply with the requirements of IFRS 10.
- The historical financial information does not therefore constitute a set of general-purpose financial statements under paragraph 3 of IAS 1 and consequently there is no explicit and unreserved statement of compliance with IFRS as contemplated by paragraph 16 of IAS 1.
- As the financial information has been prepared on a combined basis, it is not possible to measure earnings per share. Accordingly, the requirement of IAS 33 Earnings per Share" to disclose earnings per share has not been complied with.

In all other respects IFRS as adopted by the EU has been applied. The other principal accounting policies adopted in the preparation of the historical financial information are set out in note 4. The policies have been consistently applied to all periods presented, unless otherwise stated.

(b) ***Basis of measurement***

The financial information has been prepared under the historical cost convention. Historical cost is generally based on the fair value of the consideration given in exchange for the assets at the time of initial recognition.

(c) ***Functional and presentation currency***

The financial information is presented in United States Dollars (USD) and amounts have been rounded to the nearest thousand, except where otherwise indicated.

3. Adoption of new standards, amendments and interpretations

3.1 *New and revised IFRSs issued but not yet effective*

The following summarises the revisions to accounting standards and pronouncements that are applicable to the Target Companies which are issued but are not yet effective to 31 December 2018. Where IFRSs and IFRIC Interpretations listed below permit early adoption, the Target Companies have elected not to apply them in the preparation of this financial information. The full impact of all IFRS and IFRIC Interpretations is currently being assessed by the Target Companies, but other than noted below none of these pronouncements are expected to result in any material adjustments to the financial information. Revisions to accounting standards and pronouncements where there is considered to be no impact on the Target Companies have been omitted from this disclosure.

Pronouncement	*Nature of Change*	*Effective Date*
IFRS 16 "Leases"	This standard replaces the current guidance in IAS 17 and is a far-reaching change in accounting by lessees in particular. Under IAS 17, lessees were required to make a distinction between a finance lease (on balance sheet) and an operating lease (off balance sheet). IFRS 16 now requires lessees to recognise a lease liability reflecting future lease payments and a 'right-of-use asset' for virtually all lease contracts. The IASB has included an optional exemption for certain short-term leases and leases of low value assets; however, this exemption can only be applied by lessees.	Applicable to annual periods beginning on or after 1 January 2019.

Pronouncement	*Nature of Change*	*Effective Date*
	For lessors, the accounting stays almost the same. However, as the IASB has updated the guidance on the definition of a lease (as well as the guidance on the combination and separation of contracts), lessors will also be affected by the new standard. At the very least, the new accounting model for lessees is expected to impact negotiations between lessors and lessees. Under IFRS 16, a contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. IFRS 16 supersedes IAS 1-7, 'Leases', IFRIC 4, 'Determining whether an Arrangement contains a lease, SIC 15, 'Operating Leases – Incentives' and SIC 27, 'Evaluating the Substance of Transactions Involving the Legal Form of a Lease'. The Target Companies have assessed the impact of IFRS 16 by reviewing the nature of their contracts and agreements and have not identified any leases. The impact of IFRS 16 on the Target Companies is expected to be nil in the year of adoption.	
IFRIC Interpretation 23 Uncertainty over Income Tax Treatment	The interpretation addresses the determination of taxable profit (tax loss), tax bases, unused tax losses, unused tax credits and tax rates, when there is uncertainty over income tax treatments under IAS 12. It specifically considers: ● whether tax treatments should be considered collectively; ● assumptions for taxation authorities' examinations; ● the determination of taxable profit (tax loss), tax bases, unused tax losses, unused tax credits and tax rates; ● the effect of changes in facts and circumstances. The interpretation has no impact on the Target Companies' financial information.	Applicable to annual periods beginning on or after 1 January 2019.
Amendments to IAS 23 Borrowing costs	These amendments were issued in December 2017. The amendments clarify that if any specific borrowing remains outstanding after the related asset is ready for its intended use or sale, that borrowing becomes part of the funds that an entity borrows generally when calculating the capitalisation rate on general borrowings. The Target Companies do not intend to adopt the amendments before their effective date and do not expect them to have a material impact on their current or future reporting periods.	These amendments are mandatory for annual periods beginning on or after 1 January 2019.
Amendments to IAS 12 Income taxes	These amendments were issued in December 2017. These amendments clarify that all income tax consequences of dividends (including payments on financial instruments classified as equity) are recognised consistently with the transactions that generated the distributable profits. In effect, the income tax consequences of dividends are linked more directly to past transactions or events that generated distributable profits than to distributions to owners. Therefore, an entity shall recognise the income tax consequences of dividends in profit or loss, other comprehensive income or equity according to where the entity originally recognised those past transactions or events. The Target Companies do not intend to adopt the amendments before their effective date and do not expect them to have a material impact on their current or future reporting periods.	These amendments are mandatory for annual periods beginning on or after 1 January 2019.

3.2 ***Amendments to IFRSs and the new Interpretations that are mandatorily effective for the current year.***

In 2018, the Target Companies applied a number of amendments to IFRSs and a new Interpretation issued by the International Accounting Standards Board (IASB) that are mandatorily effective for an accounting period that begins on or after 1 January 2018.

Pronouncement	*Nature of Change*	*Effective Date*
IFRS 15 – Revenue from Contracts with Customers	IFRS 15 specifies that an entity should recognise revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard had an impact on SUGL's standalone financial statements, based on its gas sales to Accugas which had a significant financing component due to the time difference between receiving consideration and transfer of control being over one year. However, the Target Companies are not affected as revenue transactions between the companies were eliminated upon combination.	Applicable to annual periods beginning on or after 1 January 2018
IFRS 9 – Financial Instruments	IFRS 9 replaces IAS 39, Financial Instruments – Recognition and Measurement. The IASB developed IFRS 9 in three phases, dealing separately with the classification and measurement of financial assets, impairment and hedging. It includes requirements on the classification and measurement of financial assets and liabilities, it also includes an expected credit losses model that replaces the current incurred loss impairment model. The standard will ensure that more assets will have to be measured at fair value with changes in fair value recognised in profit and loss as they arise, possible provision for future credit losses in the very first reporting period a loan goes on the books – even if it is highly likely that the asset will be fully collectible and a greater disclosure requirement amongst others. Note 6.1 sets out details of the impact of adoption of IFRS 9 on the combined financial information.	Effective for annual periods beginning on or after 1 January 2018.

4. Summary of significant accounting policies

A summary of the principal accounting policies are set out below. These policies have been consistently applied to all the years presented, unless otherwise stated.

4.1 *Joint arrangements*

A joint arrangement is an arrangement over which two or more parties have joint control. Joint control exists when the Target Companies do not have the power, directly or indirectly, to solely govern the financial and operating policies of an entity. In assessing control, potential voting rights which are currently exercisable are taken into account. The Target Companies are engaged in oil and gas exploration, development, production and distribution through unincorporated joint ventures or jointly controlled entities. The Target Companies account for their share of assets, liabilities, revenues and expenses of unincorporated joint arrangements as joint operations.

Interest in jointly controlled entities are accounted for 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 Target Companies' share of net assets of the venture since the acquisition date. The aggregated statement of comprehensive income reflects the Target Companies' share of results of operations in the ventures.

4.2 *Basis of combination*

Inter-company transactions, balances and unrealised gains and losses on transactions between Target Companies entities are eliminated.

Business Combination Under Common Control

Business combination involving entities under common control are outside the scope of IFRS 3. Where IFRS has no specific requirements, in accordance with IAS 8, judgement is required by management in developing and applying an accounting policy that results in information that is relevant, reliable, neutral, prudent and represent faithfully the financial position of the entity. Management exercises its judgement to apply the predecessor method of accounting for business combination involving entities under common control.

Under predecessor accounting, no purchase price allocation is performed. The assets and liabilities are recorded at existing carrying values. The difference between the consideration transferred and the net assets is recognised in other reserves. All costs of combination are taken into the profit or loss and other comprehensive income in the period in which they are incurred. Where applicable, adjustments are made to achieve uniform accounting policies of the combined entities (for the entities combined in current year, no adjustments were recorded as the combining entities already maintained uniform accounting policies). The comparative amounts in the financial information are restated as if the entities had been combined throughout the previous periods and at the previous balance sheet dates. This requires a restatement of the comparative figures to include the results for all the combining entities for the previous periods and their balance sheets for the previous balance sheet dates, or since the date when the combining entities were under common control, where this is a shorter period.

4.3 *Commercial reserves*

The Target Companies define 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. There should be 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.

4.4 *Oil and natural gas exploration, evaluation and development*

4.4.1 **Oil and gas exploration and appraisal assets**

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 aggregated 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 is capitalised within upstream assets. If prospects are deemed to be impaired (unsuccessful) on completion of an evaluation, the associated capitalised costs are expensed to the aggregated statement of comprehensive income.

4.4.2 **Oil and gas assets**

Development cost

Expenditure on the construction, installation or completion of infrastructure facilities such as process plant, pipelines and the drilling of development wells is capitalised within oil and gas properties.

When a development project moves into the production stage, the capitalisation of certain construction/development costs ceases and costs are either regarded as part of the cost of inventory or expensed in the period in which they are incurred, except for costs which qualify for capitalisation relating to producing asset additions, improvements or new developments. Development and producing assets are carried at cost less accumulated depreciation, depletion and accumulated impairment losses.

4.4.3 Other property, plant and equipment

Other property, plant and equipment are stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of the decommissioning obligation, and for qualifying assets (where applicable), 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.

Property, plant and equipment under construction are disclosed as assets under construction. These amounts are not depreciated or depleted until the asset is available for use. Purchased software that is integral to the functionality of related equipment is capitalised as part of the equipment. When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

4.4.4 Depreciation/depletion

With the exception of upstream oil and gas assets, depreciation is charged to the aggregated statement of comprehensive income on a straight-line basis:

Asset Class	*Basis*
Geological and geophysical costs, exploration drilling costs and development drilling costs	Unit of production using proved and probable reserves
Leasehold land	30 years
Moveable and support assets	
● Portacabins	● 10 years
● Office equipment	● 5 years
● Vehicles	● 5 years
● Computer hardware	● 3 – 5 years
● Plant and machinery	● 5 years
● Office equipment	● 5 years
Pipeline and facilities costs	5 to 30 years
Signature bonus	Unit of production using proved and probable reserves
Exploration and development costs	Unit of production using proved and probable reserves
Capital work-in-progress	Nil

The Target Companies' 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 5 – 30 years. Depreciation is shown within depletion in the aggregated statement of comprehensive income. Infrastructure assets within oil and gas assets are depreciated on a straight-line basis.

Oil and gas assets are depreciated / depleted on a unit-of-production basis over the total proved and probable developed reserves of the field concerned, except in the case of assets whose useful life is shorter than the lifetime of the field, in which case the straight-line method is applied. Rights and concessions are depleted on the unit-of-production basis over the total proved and probable developed reserves of the relevant area. 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. Capital work-in-progress is not depreciated. The attributable cost of each asset is transferred to the relevant asset category immediately the asset is available for use and depreciated accordingly.

The asset's residual values, useful lives and methods of depreciation are reviewed at each reporting period and adjusted prospectively if appropriate.

4.4.5 **Derecognition:**

The carrying amount of an item or PPE shall be derecognised on disposal or when no future economic benefits is expected from its use or disposal. Gains and losses on disposals are determined by comparing the proceeds with the carrying amount and are recognised in profit or loss in the statement of comprehensive income.

An item of property, plant and equipment and any significant part initially recognised is derecognised upon disposal or when no future economic benefits are expected from its use or disposal. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the statement of profit or loss and other comprehensive income when the asset is derecognised.

4.4.6 **Major maintenance, inspection and repairs**

Expenditure on major maintenance refits, inspections or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset, that was separately depreciated and is written off, is replaced and it is probable that future economic benefits associated with the item will flow to the Target Companies, the expenditure is capitalised. Where part of the asset replaced was not separately considered as a component and therefore not depreciated separately, the replacement value is used to estimate the carrying amount of the replaced asset(s) which is immediately written off. Inspection costs associated with major maintenance programmes are capitalised and amortised over the period to the next inspection. All other day-to-day repairs and maintenance costs are expensed as incurred.

4.4.7 **Intangible assets**

Intangible assets include computer software and licence cost, measured on initial recognition at cost. Following initial recognition, intangible assets are carried at cost less any accumulated amortisation (calculated on a straight-line basis over their useful lives) and accumulated impairment losses, if any. Internally generated intangible assets, excluding capitalised development costs, are not capitalised. Instead, the related expenditure is recognised in statement of profit or loss in the year in which the expenditure is incurred. The useful lives of intangible assets are assessed as either finite or indefinite.

Intangible assets with finite lives are amortised over the useful economic life and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortisation period and the amortisation method for an intangible asset with a finite useful life is reviewed at least at the end of each reporting period. Changes in the expected useful life or the expected pattern of consumption of future economic benefits embodied in the asset are accounted for by changing the amortisation period or method, as appropriate, and are treated as changes in accounting estimates. The amortisation expense on intangible assets with finite lives is recognised in statement of profit or loss in the expense category consistent with the function of the intangible assets.

Intangible assets with indefinite useful lives and intangible assets not yet available for use are tested for impairment at least annually, and whenever there is an indication that the asset may be impaired.

Gains or losses arising from derecognition of an intangible asset are measured as the difference between the net disposal proceeds and the carrying amount of the asset and are recognised in statement of profit or loss when the asset is derecognised. The long-term assets held by the Target Companies are stated at cost.

4.5 *Impairment of non-financial assets*

At the end of each reporting period, the Target Companies review the carrying amounts of their tangible assets to determine whether there is any indication that those assets have suffered an impairment loss, in accordance with IAS 36 Impairment of Assets. 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). When it is not possible to estimate the recoverable amount of an individual asset, the entity estimates the recoverable amount of the cash-generating unit (CGU) to which the asset belongs. The CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Exploration and Evaluation (E&E) assets are assessed for impairment when they are reclassified to PP&E, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. E&E assets not reclassified to PP&E are assessed for impairment on a CGU basis in accordance with IFRS 6 Exploration for and Evaluation of Mineral Resources.

When a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

If an impairment indicator trigger is identified for a tangible asset the relevant asset or cash generating unit is tested for recoverability. The recoverable amount is the higher of fair value less costs to sell (FVLTCS) and value in use. 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. FVLCTS is based on available market information, where applicable. The Target Companies generally estimate fair value less costs to sell using a discounted cash flow model which has a significant number of assumptions. The model uses expected cash flows from proved plus probable reserves. Reserve estimates and expected future cash flows from production of reserves are subject to measurement uncertainty and subject to variability to changes in forecasted commodity prices. The discount rate applied to the cash flows is also subject to management's judgment and will affect the recoverable amount calculated. Commodity price changes impact the expected future cash flows which may require a material adjustment to the carrying value of tangible assets. The Target Companies monitor internal and external indicators of impairment relating to their tangible assets. These indicators include changes in commodity prices, reserve volumes and discount rates.

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 (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognised immediately in the statement of profit or loss and other comprehensive income, unless the relevant asset is carried at a revalued amount, in which case the impairment loss is treated as a revaluation decrease. When an impairment loss subsequently reverses, the carrying amount of the asset (or a 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 (or cash generating unit) in prior years.

A reversal of an impairment loss is recognised in the aggregate statement of profit or loss and other comprehensive income unless the relevant asset is carried at a revalued amount, in which case the reversal of the impairment loss is treated as revaluation increase.

4.6 *Production costs*

The cost of producing oil or gas from a developed well are charged to the statement of comprehensive income in the year in which they are incurred and includes movements in oil and gas inventory.

4.7 *Taxation*

4.7.1 **Current income tax**

The income tax expense for the period comprises current and deferred tax expense. Tax is recognised in the statement of comprehensive income except to the extent that it relates to items recognised in other comprehensive income or directly in equity. In this case, the tax is also recognised in other comprehensive income or directly in equity, respectively. The current income tax is calculated on the basis of the tax laws enacted or substantially enacted at the reporting date where the Target Companies operate and generate taxable income.

The tax currently payable is based on taxable profit for the year. 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 years, but it further excludes items that are never taxable or deductible.

The Target Companies are subject to the following types of current income tax:

- Company Income Tax – This relates to the amount of income tax payable on the taxable profit of the year determined in accordance with the Company Income Tax ACT, CAP C21 LFN 2004 (as amended).
- Petroleum Profits Tax – This is governed by the Petroleum Profits Tax Act CAP P13 LFN 2004.
- Tertiary Education Tax – Tertiary education tax is assessed at 2 per cent. of the assessable profit in line with Tertiary Education Trust Fund Act CAP E8, LFN 2011.

4.7.2 **Deferred taxation**

Deferred tax is recognised in respect of temporary timing differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. 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.

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 determined on a non-discounted basis using tax rates and laws enacted or substantively enacted by the statement of financial position date and expected to apply when the deferred tax asset or liability is settled. 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 Target Companies intend to settle their current tax assets and liabilities on a net basis.

4.8 *Foreign currency translation*

The individual Financial information of each entity within the Target Companies are presented in the currency of the primary economic environment in which it operates (its functional currency). The functional currency of the Target Companies' entities is the US Dollar, which represents the currency of the primary economic environment in which the entities operate and is also the presentation currency for the aggregated Financial information.

In preparing the aggregated Financial information of the individual companies comprising the Target Companies, transactions in currencies other than the entity's functional currency (foreign currencies) are recorded at the rates of exchange prevailing on the dates of the transactions. 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.

4.9 *IFRS 15 – Revenue from contracts with customers (policy applied from 1 January 2018)*

The Target Companies applied the principles of IFRS 15 in determining and recognizing revenue on their transactions for the year 2018. IFRS 15 establishes a comprehensive framework for determining whether, how much and when revenue is recognised. It replaced IAS 18 Revenue, IAS 11 Construction Contracts and related interpretations. The standard contains a single model that applies to contracts with customers and two approaches to recognising revenue: at a point in time or over time. The standard defined a new five-step model to recognise revenue from customer contracts. The core principle of IFRS 15 is that an entity recognises revenue to depict the transfer of promised goods or services to customers at an amount that reflects the consideration which the entity expects to be entitled to in exchange for those goods and services. The standard had an impact on SUGL's standalone financial statements, based on its gas sales to Accugas which had a significant financing component. However, the Target Companies are not affected as the revenue between SUGL and Accugas is eliminated upon combination.

The Target Companies are principally engaged in the exploration, development and production of crude oil and natural gas, as well as the processing, marketing and distribution of gas. The Target Companies have generally concluded that it is the principal in their revenue arrangements, because they typically control the goods or services before transferring them to the customer.

The disclosures of significant accounting judgements, estimates and assumptions relating to revenue from contracts with customers are provided in Note 5 (See below on significant accounting judgements).

Sale of gas

Revenue from sale of gas delivered is recognised over time when control of the asset is transferred to the customer, generally on delivery of the gas at the delivery point. The normal credit term is 30 days upon delivery.

The Target Companies consider whether there are other promises in the contract that are separate performance obligations to which a portion of the transaction price needs to be allocated. The promised quantity of gas committed to be transferred to the customer in the contract is the minimum quantity of gas to be purchased by the customer in Standard Cubic Feet (SCF). Purchases above and beyond the estimated minimum has been considered optional purchases and accounted for as separate contracts at a price that would reflect the stand-alone selling price of the gas delivered. In determining the transaction price for the sale of gas, the Target Companies consider the existence of significant financing components and consideration payable to the customer (if any).

Sales of crude oil and condensates

Revenue from sales of crude oil and condensates is recognised at the point in time when control of the asset is transferred to the customer, generally on delivery of the processed crude at the delivery point. The normal credit term is 30 days upon delivery.

Significant financing component

For gas sales transactions, the receipt of the consideration by the Target Companies does not match the timing of the transfer of gas to the customer (e.g., the consideration is paid after the gas has been delivered). Where the Target Companies expect, at contract inception, that the period between the transfer of the promised good to the customer and when the customer pays for that good or service will be more than a year, the Target Companies will adjust the promised amount of consideration for the effects of a significant financing component. Where the period is expected to be one year or less, the Target Companies apply the practical expedient in IFRS 15, and do not adjust the promised amount of consideration for the effects of a significant financing component.

For contracts where adjustments are made, the transaction price for such contracts is discounted, using the rate that would be reflected in a separate financing transaction between the Target Companies and their customers at contract inception, to take into consideration the significant financing component.

For crude oil sales transactions, the receipt of the consideration by the Target Companies does not match the timing of the transfer of the crude oil to the customer (i.e., the consideration is paid after the crude oil has been delivered). Using the practical expedient in IFRS 15, the Target Companies do not adjust the promised amount of consideration for the effects of a significant financing component since they expect, at contract inception, that the period between the transfer of the promised good or service to the customer and when the customer pays for that good or service will be one year or less.

Consideration payable to a customer

The payment of the costs, claims, demands, liabilities and/or expenses suffered or incurred by the Buyer under the gas contract (if any) has been recognised as a reduction of the transaction prices and therefore, of revenue since the payment to the customer is not in exchange for distinct goods that the customers transfer to the Target Companies.

Contract balances

Contract assets

A contract asset is the right to consideration in exchange for goods or services transferred to the customer. If the Target Companies perform by transferring goods or services to a customer before the customer pays consideration or before payment is due, a contract asset is recognised for the earned consideration that is conditional.

Trade receivables

A receivable represents the Target Companies' right to an amount of consideration that is unconditional (i.e., only the passage of time is required before payment of the consideration is due). Refer to accounting policies of financial assets under financial instruments – initial recognition and subsequent measurement.

Contract liabilities

A contract liability is the obligation to transfer goods or services to a customer for which the Target Companies have received consideration (or an amount of consideration is due) from the customer. If a customer pays consideration before the Target Companies transfer goods or services to the customer, a contract liability is recognised when the payment is made, or the payment is due (whichever is earlier). Contract liabilities are recognised as revenue when the Target Companies perform under the contract.

4.10 *IAS 18 – Revenue recognition (policy applied before 1 January 2018)*

For the years 2016 and 2017, the Target Companies applied the accounting policy presented below in accounting for revenue earned, in accordance with IAS 18.

Revenue is recognised to the extent it is probable that the economic benefits will flow to the Target Companies and the revenue can be reliably measured. Revenue is measured at the fair value of the consideration received, excluding discounts, sales taxes, excise duties and similar levies. The Target

Companies assess their revenue arrangements against specific criteria in order to determine if they are acting as principal or agent.

Revenue from the sale of oil, gas and petroleum products is recognised when the significant risks and rewards of ownership have been transferred, which is considered to occur when title passes to the customer. This generally occurs when the product is physically transferred into a vessel, pipe or other delivery mechanism. Revenue is also derived from the invoiced value of tariffs charged by the Target Companies for the sale and delivery of gas through their pipelines.

Take or pay contract (Off take Contract)

Under these contracts, the Target Companies make a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. These commitments contain protective (force majeure) and adjustment provisions. If a buyer has a right to get a "make-up" delivery at a later date, revenue recognition is deferred (now accounted for as a contract liability) and only recognised when the product is delivered, or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognised when the take-or-pay penalty is triggered.

Interest income

For all financial instruments measured at amortised cost and interest-bearing financial assets classified as available for sale, interest income or expense is recorded using the effective interest rate (EIR), which is the rate that exactly discounts the estimated future cash payments or receipts through the expected life of the financial instrument or a shorter period, where appropriate, to the net carrying amount of the financial asset or liability. Interest income is included in finance income in the statement of profit or loss and other comprehensive income.

4.11 *Borrowing costs*

Borrowing costs directly attributable to the acquisition, construction or production of an asset that necessarily takes a substantial period of time to get ready for its intended use or sale (a qualifying asset) are capitalised as part of the cost of the respective assets. Borrowing costs consist of interest and other costs that an entity incurs in connection with the borrowing of funds.

Where funds are borrowed specifically to finance a project, the amount capitalised represents the actual borrowing costs incurred. Where surplus funds are available for a short term out of money borrowed specifically to finance a project, the income generated from the temporary investment of amounts is also capitalised and deducted from the total capitalised borrowing cost. Where the funds used to finance a project form part of general borrowings, the amount capitalised is calculated using a weighted average of rates applicable to relevant general borrowings of the respective Group companies during the period.

All other borrowing costs are recognised in statement of profit or loss in the period in which they are incurred. Even though exploration and evaluation assets can be qualifying assets, they generally do not meet the probable economic benefit test and also are rarely debt funded. Any related borrowing costs are therefore generally recognised in the aggregated statement of profit or loss in the period they are incurred.

4.12 *Inter group loans (policy applied before 1 January 2018)*

Inter group loans relate to borrowings owed to other related companies which are not part of the Target Companies.

Interest-free short-term inter group loans

Short term related party loans are expected to be repaid in the near future and are recorded at the proceeds of the loan amount as a close approximation to the fair value. These balances are recorded within current liabilities.

Interest-free fixed term inter group loans

Interest-free fixed term inter group loans are recognised initially at fair value, estimated by discounting the future loan repayments using an interest rate based on an estimated market rate. Where the loan is from a parent to a subsidiary, the difference between the proceeds of the loan amount and the fair value is recorded as:

- an investment in the parent's financial statements
- a loan discount reserve within equity in the subsidiary's financial statements.

Subsequently, the loan is measured at amortised cost, using the effective interest method. The unwinding of the discount is recorded as finance income in the statement of profit or loss and other comprehensive income of the parent and as a finance cost in the subsidiary's statement of profit or loss and other comprehensive income with a corresponding transfer from the loan discount reserve to retained reserves over the life of the loan. Estimates of repayments are evaluated in future periods and revised if necessary.

4.13 *Inventories*

Inventories of oil and gas assets are stated at their net realisable values and changes 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.

Pipeline fill

Natural gas which is necessary to bring a pipeline into working order is treated as a part of the cost of the related pipeline on the basis that it is not held for sale or consumed in a production process but is necessary for the operation of a facility during more than one operating cycle. Also, its cost cannot be recouped through sale (or is significantly impaired). This applies even if the part of inventory that is deemed to be an item of property, plant and equipment (PP&E) cannot be separated physically from the rest of inventory. It is valued at cost and is depreciated over the useful life of related asset.

4.14 *Provisions*

(a) **General**

Provisions are recognised when the Target Companies have a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of the obligation can be made. Provisions are measured at the Target Companies' 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. Where discounting is used, the increase in the provision due to the passage of time is recognised as a finance cost in the statement of profit or loss and other comprehensive income.

Provisions are not recognised for future operating losses. Where there are a number of similar obligations, the likelihood that an outflow will be required in settlement is determined by considering the class of obligations as a whole. A provision is recognised even if the likelihood of an outflow with respect to any one item included in the same class of obligations may be small.

A possible obligation i.e. contingent liability is disclosed but not accrued. However, disclosure is not made if payment is remote. Provision for settlement of litigation is measured as the most likely amount payable, as advised by the Target Companies' solicitors. Provision for warranties is measured at a probability weighted expected value.

When some or all of the economic benefits required to settle a provision are expected to be recovered from a third party, a receivable is recognised as an asset if it is virtually certain that reimbursement will be received and the amount of the receivable can be measured reliably.

(b) **Decommissioning liability**

The Target Companies recognise a decommissioning liability if they have a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. The obligation generally arises when the asset is installed, or the ground/environment is disturbed at the location. When the liability is initially recognised, the present value of the estimated costs is capitalised by increasing the carrying amount of the related oil and gas assets to the extent that it was incurred by the development/construction of the asset. Any decommissioning obligations that arise through the production of inventory are expensed as incurred. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment.

Any reduction in the decommissioning liability and, therefore, any deduction from the asset to which it relates, may not exceed the carrying amount of that asset. If it does, any excess over the carrying value is taken immediately to the statement of profit or loss and other comprehensive income. If the change in estimate results in an increase in the decommissioning liability and, therefore, an addition to the carrying value of the asset, the Target Companies consider whether this is an indication of impairment of the asset as a whole, and if so, tests for impairment in accordance with IAS 36. If, for mature fields, the revised oil and gas asset net of decommissioning provisions exceeds the recoverable value, that portion of the increase is charged directly to expense.

Over time, the discounted liability is increased for the change in present value based on the discount rate that reflects current market assessments and the risks specific to the liability. The periodic unwinding of the discount is recognised in the statement of profit or loss and other comprehensive income as a finance cost.

The Target Companies recognise neither the deferred tax asset arising from the temporary difference on the decommissioning liability nor the corresponding deferred tax liability regarding the temporary difference on a decommissioning asset, as such costs are deductible as spent and as these costs will be incurred at the end of the asset life, at which point it is expected that no taxable profits will be generated, these will not be deductible.

4.15 *IFRS 9 – Financial instruments (policy applied from 1 January 2018)*

The Target Companies' accounting policies were changed to comply with IFRS 9. IFRS 9 replaces the provisions of IAS 39 that relate to the recognition, classification and measurement of financial assets and financial liabilities; derecognition of financial instruments; impairment of financial assets; and hedge accounting. IFRS 9 also significantly amends other standards dealing with financial instruments such as IFRS 7 Financial Instruments: Disclosures.

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument of another entity.

(a) **Financial assets**

Initial recognition and measurement

Financial assets are classified at initial recognition as, amortised cost, fair value through other comprehensive income (OCI), or fair value through profit or loss. Financial assets are subsequently measured at amortised cost, fair value through other comprehensive income, or fair value through profit or loss.

The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Target Companies' business model for managing them. With the exception of trade receivables that do not contain a significant financing component or for which the Target Companies have applied the practical expedient in IFRS 15.63 regarding payments expected within one year or less, the Target Companies initially measure a financial asset at its fair value plus, in the case of a financial asset not at fair value through profit or loss, transaction costs. Trade receivables that do not contain a significant financing component or for which the Target Companies have applied the practical expedient are measured at the transaction price determined under IFRS 15. Refer to the accounting policies on revenue from contracts with customers.

For a financial asset to be classified and measured at amortised cost or fair value through OCI, it needs to give rise to cash flows that are 'solely payments of principal and interest (SPPI)' on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level. The Target Companies' business model for managing financial assets refers to how they manage their financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both. Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the market place (regular way trades) are recognised on the trade date, i.e., the date that the Target Companies commit to purchase or sell the asset.

Subsequent measurement

For purposes of subsequent measurement, financial assets are classified in four categories:

- Financial assets at amortised cost (debt instruments)
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments)
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments)
- Financial assets at fair value through profit or loss

The Target Companies' financial assets include financial assets at amortised cost.

Financial assets at amortised cost (debt instruments)

The Target Companies measure financial assets at amortised cost if both of the following conditions are met:

- the financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- the contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Financial assets at amortised cost are subsequently measured using the effective interest (EIR) method and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

The Target Companies' financial assets at amortised cost include trade receivables, other receivables, receivables from other related parties and loan receivables from other related parties.

Derecognition

A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is primarily derecognised (i.e., removed from the Target Companies' statement of financial position) when:

- The rights to receive cash flows from the asset have expired; or

- The Target Companies have transferred their rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Target Companies have transferred substantially all the risks and rewards of the asset, or (b) the Target Companies have neither transferred nor retained substantially all the risks and rewards of the asset, but have transferred control of the asset.

When the Target Companies have transferred their rights to receive cash flows from an asset or have entered into a pass-through arrangement, they evaluate if, and to what extent, they have retained the risks and rewards of ownership. When they have neither transferred nor retained substantially all of the risks and rewards of the asset, nor transferred control of the asset, the Target Companies continue to recognise the transferred asset to the extent of its continuing involvement. In that case, the Target Companies also recognise an associated liability. The transferred asset and the associated liability are measured on a basis that reflects the rights and obligations that the Target Companies have retained.

Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the Target Companies could be required to repay.

Impairment of financial assets

The Target Companies recognise an allowance for expected credit loss (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Target Companies expect to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms (if any). ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit loss that result from default events that are possible within the next 12-months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit loss expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Target Companies apply a simplified approach in calculating ECLs. Therefore, the Target Companies do not track changes in credit risk, but instead recognise a loss allowance based on lifetime ECLs at each reporting date. The Target Companies have established a provision matrix that is based on their historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. For receivables from related parties, the Target Companies apply the general approach. The general approach involves tracking the changes in the credit risk and recognising a loss allowance based on a twelve-month ECL at each reporting date. Increase in credit risk will give rise to moving receivables from stage 1 to stage 2 and then stage 3, as defined below:

- **Stage 1** is where credit risk has not increased significantly since initial recognition. For financial assets in stage 1, entities are required to recognise 12-month ECL and recognise interest income on a gross basis – this means that interest will be calculated on the gross carrying amount of the financial asset before adjusting for ECL.
- **Stage 2** is where credit risk has increased significantly since initial recognition. When a financial asset transfers to stage 2 entities are required to recognise lifetime ECL but interest income will continue to be recognised on a gross basis.
- **Stage 3** is where the financial asset is credit impaired. This is effectively the point at which there has been an incurred loss event under the IAS 39 model. For financial assets in stage 3, entities will continue to recognise lifetime ECL but they will now recognise interest income on a net basis. This means that interest income will be calculated based on the gross carrying amount of the financial asset less ECL.

The Target Companies calculate ECLs based on three probability-weighted scenarios to measure the expected cash shortfalls, discounted at an approximation to the EIR. A cash shortfall is the difference between the cash flows that are due to an entity in accordance with the contract and the cash flows that the entity expects to receive.

The mechanics of the ECL calculations are outlined below and the key elements are, as follows:

- PD – The Probability of Default is an estimate of the likelihood of default over a given time horizon.
- EAD – The Exposure at Default is an estimate of the exposure at a future default date, taking into account expected changes in the exposure after the reporting date, including repayments of principal and interest, whether scheduled by contract or otherwise.
- LGD – The Loss Given Default is an estimate of the loss arising in the case where a default occurs at a given time. It is based on the difference between the contractual cash flows due and those that the Target Companies would expect to receive, including from the realisation of any collateral. It is usually expressed as a percentage of the EAD.

When estimating the ECLs, the Target Companies consider three scenarios (a base case, an upside, a downside). Each of these is associated with different PDs, EADs and LGDs. In their ECL models, the Target Companies rely on a broad range of forward-looking information as economic inputs, such as:

- GDP growth
- Oil price
- Exchange rate
- Inflation rate

Write-offs

The Target Companies' accounting policy under IFRS 9 remains the same as it was under IAS 39. Financial assets are written off either partially or in their entirety only when the Target Companies have stopped pursuing the recovery. If the amount to be written off is greater than the accumulated loss allowance, the difference is first treated as an addition to the allowance that is then applied against the gross carrying amount. Any subsequent recoveries are credited to profit or loss. Write-offs are included in other operating expenses, unless material. When write-offs are material, they are separately disclosed as a line item on the statement of profit or loss and other comprehensive income.

(b) **Financial liabilities**

Initial recognition and measurement

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, or payables, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs. The Target Companies' financial liabilities include trade and other payables and loans and borrowings.

Subsequent measurement

The measurement of financial liabilities depends on their classification, as described below:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss. Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Target Companies that are not designated as hedging instruments in hedge relationships as defined by IFRS 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments. Gains or losses on liabilities held for trading are recognised in profit or loss. Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in IFRS 9 are satisfied. The Target Companies have not designated any financial liability as at fair value through profit or loss.

Loans and borrowings

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the EIR method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process. Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in profit or loss. This category generally applies to interest-bearing loans and borrowings.

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

Modification

When the contractual cash flows of a financial instrument are renegotiated or otherwise modified and the renegotiation or modification does not result in the derecognition of that financial instrument, the Target Companies recalculate the gross carrying amount of the financial instrument and recognise a modification gain or loss immediately within finance income/(cost) – net at the date of the modification. The gross carrying amount of the financial instrument is recalculated as the present value of the renegotiated or modified contractual cash flows that are discounted at the financial instrument's original effective interest rate.

Offsetting of financial instruments

Financial assets and financial liabilities are offset, and the net amount is reported in the statement of financial position if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis, to realise the assets and settle the liabilities simultaneously.

4.16 *IAS 39 – Financial instruments (policy applied before 1 January 2018)*

The accounting policy on financial instruments below is in accordance with IAS 39 and was strictly applied to financial instruments in the periods before 2018.

(a) **Financial assets**

Initial recognition and measurement

Financial assets within the scope of IAS 39 Financial Instruments: Recognition and Measurement are classified as financial assets at fair value through profit or loss, loans and receivables, held to maturity investments, available for sale financial assets, as appropriate. The Target Companies determine the classification of their financial assets at initial recognition.

All financial assets are recognised initially at fair value plus (in the case of investments not at fair value through profit or loss) directly attributable transaction costs.

The Target Companies' financial assets include cash and short-term deposits, trade and other receivables and loan and other receivables.

Subsequent measurement

The subsequent measurement of financial assets depends on their classification as follows:

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments as defined by IAS 39.

Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value recognised in finance income or finance costs (as appropriate) in the statement of profit or loss.

Financial assets designated upon initial recognition at fair value through profit or loss are designated at the initial recognition date and only if the criteria set out in IAS 39 are satisfied.

The Target Companies evaluate their financial assets as held for trading, other than derivatives, to determine whether the intention to sell them in the near term is still appropriate. When, in rare circumstances, the Target Companies are unable to trade these financial assets due to inactive markets and management's intention to sell them in the foreseeable future significantly changes, the Target Companies may elect to reclassify these financial assets.

The reclassification to loans and receivables, available for sale or held to maturity depends on the nature of the asset. This evaluation does not affect any financial assets designated at fair value through profit or loss using the fair value option at designation, these instruments cannot be reclassified after initial recognition.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not held for trading or designated at fair value though profit or loss. These embedded derivatives are measured at fair value with changes in fair value recognised in the statement of profit or loss and other comprehensive income. Reassessment only occurs if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required.

Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, such financial assets are subsequently measured at amortised cost using the effective interest rate method ("EIR"), less impairment. Amortised cost is calculated by taking into account any discount or premium on acquisition and fee or costs that are an integral part of the EIR. The EIR amortisation is included in finance income in the statement of profit or loss and other comprehensive income.

The losses arising from impairment are recognised in the statement of profit or loss and other comprehensive income in finance costs for loans and in cost of sales or other operating expenses for receivables.

Cash and cash equivalents

Cash and cash equivalents in the statement of financial position comprise cash at banks and at hand and short-term deposits with an original maturity of three months or less but exclude any restricted cash which is not available for use by the Target Companies and therefore is not considered highly liquid.

For the purpose of the statement of cash flows, cash and cash equivalents consist of cash and cash equivalents as defined above.

Derecognition

A financial asset (or, where an applicable part of a financial asset or part of a group of similar financial assets) is derecognised when:

- The right to receive cash flows from the asset have expired.
- The Target Companies have transferred their rights to receive cash flows from the asset or have assumed an obligation to pay the received cash flows in full without material delay to a third party under a pass-through arrangement; and either (a) the Target Companies have transferred substantially all the risks and rewards of the asset, or (b) the Target Companies have neither transferred nor retained substantially all the risks and rewards of the asset, but have transferred control of the asset.

When the Target Companies have transferred their rights to receive cash flows from an asset or have entered into a pass-through arrangement, they evaluate if, and to what extent, they have retained the risks and rewards of ownership. When they have neither transferred nor retained substantially all the risks and rewards of the asset nor transferred control of the asset, the asset is recognised to the extent of the Target Companies' continuing involvement in the asset. In that case, the Target Companies also recognise an associated liability. The transferred asset and the associated liability are measured on a basis that reflects the rights and obligations that the Target Companies have retained.

Continuing involvement that takes the form of a guarantee over the transferred asset is measured at the lower of the original carrying amount of the asset and the maximum amount of consideration that the Target Companies could be required to repay.

Impairment of financial assets

The Target Companies assess at each reporting date whether there is any objective evidence that a financial asset or a group of financial assets is impaired. A financial asset or a group of financial assets is deemed to be impaired if, and only if, there is objective evidence of impairment as a result of one or more events that has occurred after the initial recognition of the asset (an incurred loss event) and that loss event has an impact on the estimated future cash flows of the financial asset or the Target Companies of financial assets that can be reliably estimated. Evidence of impairment may include indications that the debtor or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganisation and where observable data indicate that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults.

Financial assets carried at amortised cost

For financial assets carried at amortised cost, the Target Companies first assess individually whether objective evidence of impairment exists individually for financial assets that are individually significant, or collectively for financial assets that are not individually significant.

If the Target Companies determine that no objective evidence of impairment exists for an individually assessed financial asset, whether significant or not, they include the asset in a group of financial assets with similar credit risk characteristics and collectively assesses them for impairment.

Assets that are individually assessed for impairment and for which an impairment loss is, or continues to be, recognised are not included in a collective assessment of impairment.

If there is objective evidence that an impairment loss has incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not yet been incurred).

The present value of the estimated future cash flows is discounted at the financial asset's original effective interest rate. If a loan has a variable interest rate, the discount rate for measuring any impairment loss is the current effective interest rate.

The carrying amount of the asset is reduced through the use of an allowance account and the amount of the loss is recognised in the statement of profit or loss and other comprehensive income. Interest income continues to be accrued on the reduced carrying amount and is accrued using the rate of interest used to discount the future cash flows for the purpose of measuring the impairment loss. The interest income is recorded as part of finance income in the statement of profit or loss and other comprehensive income. Loans together with the associated allowance are written off when there is no realistic prospect of future recovery and all collateral has been realised or has been transferred to the Target Companies.

If, in a subsequent year, the amount of the estimated impairment loss increases or decreases because of an event occurring after the impairment was recognised, the previously recognised impairment loss is increased or reduced by adjusting the allowance account. If a future write-off is later recovered, the recovery is credited to finance costs in the statement of profit or loss and other comprehensive income.

(b) **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 Target Companies after deducting all its liabilities. Equity instruments issued by the Target Companies are recorded at the proceeds received, net of direct issue costs.

Financial liabilities

Initial recognition and measurement

Financial liabilities within the scope of IAS 39 are classified as financial liabilities at fair value through profit or loss and other financial liabilities measured at amortised cost using the effective interest method. The Target Companies determine the classification of its financial liabilities at initial recognition.

All financial liabilities are recognised initially at fair value plus, in the case of loans and borrowings, directly attributable transaction costs.

The Target Companies' financial liabilities include trade and other payables and loans and borrowings.

Subsequent measurement

The measurement of financial liabilities depends on their classification as described below:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are acquired for the purpose of selling in the near term. This category includes derivative financial instruments entered into by the Target Companies that are not designated as hedging instruments in hedge relationships as defined by IAS 39. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognised in the statement of profit or loss and other comprehensive income.

Financial liabilities designated upon initial recognition at fair value through profit and loss should be designated at the initial recognition date and only if the criteria set out in IAS 39 are satisfied. The Target Companies have not designated any financial liability as at fair value through profit or loss.

Other financial liabilities at amortised cost

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the EIR method. Gains and losses are recognised in the statement of profit or loss and other comprehensive income when the liabilities are derecognised, as well as through the EIR method amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fee or costs that are an integral part of the EIR. The EIR amortisation is included in finance cost in the statement of profit or loss and other comprehensive income.

Derecognition

A financial liability is derecognised when the associated obligation is discharged or cancelled or expires.

When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss and other comprehensive income.

Offsetting financial instruments

Financial assets and financial liabilities are offset, and the net amount reported in the statement of financial position if, and only if, there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis, or to realise the assets and settle the liabilities simultaneously.

Fair value of financial instruments

The fair value of financial instruments that are traded in active markets at each reporting date is determined by reference to quoted market prices or dealer price quotations (bid price for long positions and ask price for short positions), without any deduction for transaction costs.

For financial instruments not traded in an active market, the fair value is determined using appropriate valuation techniques. Such techniques may include: using recent arm's length market transactions; reference to the current fair value of another instrument that is substantially the same; a discounted cash flow analysis or other valuation models.

4.17 *Cash and cash equivalents*

Cash and cash equivalents in the statement of financial position comprise cash at banks and at hand and short-term deposits with an original maturity of three months or less, but exclude any restricted cash which is not available for use by the Target Companies and therefore is not considered highly liquid. For the purpose of the statement of cash flows, cash and cash equivalents consist of cash and cash equivalents as defined.

4.18 *Finance income and expense*

Finance expense comprises interest expense on borrowings, accretion on decommissioning liabilities and bank and other finance charges. Finance income comprises interest earned on cash and cash equivalents, short-term investments and financial instruments through profit and loss.

4.19 *Employee benefits*

(a) **Defined contribution plan**

In line with the Pension Reform Act, 2014, the Target Companies remit employees' contribution to designated Pension Fund Administrators. The Target Companies and their employees respectively contribute 10 per cent. and 8 per cent. of the employees' current salaries and designated allowances into a separate entity. Employee's contributions to the scheme are funded through payroll deductions while the Target Companies' contributions are charged to profit or loss in the period to which the contributions relate. The Target Companies have no legal or constructive obligation to pay further contributions if the fund does not hold sufficient assets.

(b) **Short-term employee benefits**

Rewards

Short-term employee benefits are rewards such as wages, salaries, paid annual leave, and bonuses (if payable within twelve months of the end of the period) and non-monetary benefits (such as medical care, housing, cars, etc.)

Medical Insurance Scheme

The Target Companies subscribe to a medical insurance plan on behalf of their employees, paying a gross premium to a health management organization based on the level of the employee. This premium is treated as a prepayment and charged to staff costs on a monthly basis.

Short-term employee benefit obligations are measured on an un-discounted basis and are expensed as the related service is provided. A liability is recognised for the amount expected to be paid under short-term cash bonus or profit-sharing plans if the Target Companies have a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

(c) **End of service benefit – defined benefit gratuity scheme**

Lump sum benefits payable upon retirement or resignation of employment are fully accrued over the service lives of staff under the scheme. Employees under the defined benefit scheme are entitled to 7 per cent. of Annual Gross Salary for every completed year of service. The actuarial techniques used to assess the value of the defined benefit plans involve financial assumptions (discount rate, rate of return on assets, medical costs trend rate) and demographic assumptions (salary increase rate, employee turnover rate, etc.). The Target Companies use the assistance of an external independent actuary in the assessment of these assumptions.

As required by IAS 19, the Target Companies have adopted the Projected Unit Credit (PUC) method to establish the value of the accrued liabilities. In calculating the liabilities, the method:

- Recognises the service rendered by each member of staff at the review date;
- Anticipates that salaries will increase between the review date and the eventual exit date of the employee via withdrawal, death or retirement; and then
- Discounts the expected benefit payments to the review date.

The emerging total value (for each individual) is described by IAS 19 as the Defined Benefit Obligation (DBO).

(d) **Other long-term employee benefits**

The Target Companies' other long-term employee benefits represent Long Service Awards payable upon completion of certain years in service and accrued over the service lives of the employees. Independent actuarial valuations are performed periodically on a projected unit credit basis. Actuarial gains or losses and curtailment gains or losses arising from valuations are charged in full to income statement.

(e) **Termination benefits**

Termination benefits are expensed at the earlier of when the Target Companies can no longer withdraw the offer of those benefits and when the Target Companies recognise costs for a restructuring. If benefits are not expected to be settled wholly within 12 months of the end of the reporting period, then they are discounted.

5. Critical accounting judgements and key sources of estimation uncertainty

The preparation of the financial information in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent liabilities at the date of the financial information, and the reported amounts of revenues and expenses during the reporting period. Estimates and assumptions are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ from these estimates if different assumptions were used and different conditions existed.

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.

The following are the key assumptions and other sources of estimation uncertainty at the balance sheet date that may have a significant effect on the amounts recognised in the Financial Information.

Critical accounting judgements

5.1 *Revenue from contracts with customers – timing of recognition*

The Target Companies concluded that revenue from gas delivered and crude oil processing services will be recognised overtime because, as the Target Companies perform, the customer simultaneously receives and consumes the benefits provided by the Target Companies. The fact that another entity would not need to re-perform the processing or re-deliver the gas that the Target Companies have provided to date demonstrates that the customer simultaneously receives and consumes the benefits of the Target Companies' performance as the Target Companies perform. On the other hand, the Target Companies have determined that revenue from the sale of crude oil will be recognised at a point in time, as control is passed to the customer.

The Target Companies have determined that the output method is the best method in measuring progress of quantity of gas delivered and crude oil processing because there is a direct relationship between the Target Companies' effort (i.e., quantity delivered or processed) and the transfer of goods and service to the customer. Units delivered or processed as an output method appropriately depicts how the Target Companies transfer control to their customers. The group recognises revenue on the basis of the actual quantity of gas delivered and quantity of crude oil processed relative to the total expected gas to be delivered and crude oil to be processed.

5.2 *Provision for expected credit losses of trade receivables*

The Target Companies use a provision matrix to calculate ECLs for trade receivables. The provision rates are based on days past due for groupings of various customer segments that have similar loss patterns (i.e., by customer type). The provision matrix is initially based on the Target Companies' historical observed default rates. The Target Companies will calibrate the matrix to adjust the historical credit loss experience with forward-looking information. For instance, if forecast economic conditions (i.e., gross domestic product) are expected to deteriorate over the next year which can lead to an increased number of defaults in the manufacturing sector, the historical default rates are adjusted. At every reporting date, the historical observed default rates are updated and changes in the forward-looking estimates are analysed.

The assessment of the correlation between historical observed default rates, forecast economic conditions and ECLs is a significant estimate. The amount of ECLs is sensitive to changes in circumstances and of forecast economic conditions. The Target Companies' historical credit loss experience and forecast of economic conditions may also not be representative of customer's actual default in the future. The information about the ECLs on the Target Companies' restricted cash, trade and other receivables is disclosed in the note below.

5.3 *Measurement of the expected credit loss allowance for financial assets*

The measurement of the expected credit loss allowance for financial assets measured at amortised cost is an area that requires the use of complex models and significant assumptions about future economic conditions and credit behavior (e.g. the likelihood of customers defaulting and the resulting losses). Explanation of the inputs, assumptions and estimation techniques used in measuring ECL is further discussed, which also sets out key sensitivities of the ECL to changes in these elements.

A number of significant judgements are also required in applying the accounting requirements for measuring ECL, such as:

- Determining criteria for significant increase in credit risk;
- Choosing appropriate models and assumptions for the measurement of ECL;
- Establishing the number and relative weightings of forward-looking scenarios for each type of product/market and the associated ECL; and
- Establishing groups of similar financial assets for the purposes of measuring ECL.

5.4 *Exploration and evaluation expenditures*

The decision to transfer assets from E&E to property, plant and equipment ("**PP&E**") is based on the estimated proved reserves used in the determination of an area's technical feasibility and commercial viability and are assessed for impairment if the facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The determination of fair value requires judgments of similar transactions and expectations associated with future reserve and resource exploitation.

5.5 *Determination of cash generating units ("CGUs")*

The determination of CGUs requires judgment in defining a group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs are determined by similar geological structure, shared infrastructure, geographical proximity, commodity type, similar exposure to market risks and materiality.

5.6 *Income taxes*

Judgement is required to determine which types of arrangements are considered to be a tax on income in contrast to an operating cost. Judgement is also required in determining whether deferred income tax assets are recognised in the statement of financial position. Deferred income tax assets, including those arising from un-utilised tax losses, require management to assess the likelihood that the Target Companies will generate sufficient taxable earnings in future periods, in order to utilise recognised deferred income tax assets.

The deferred tax assets presented in the combined financial information are based on estimated future taxable profits of the Target Companies. These estimates of future taxable income are based on forecast cash flows from operations (which are impacted by production and sales volumes, oil and natural gas prices, reserves, operating costs, decommissioning costs, capital expenditure, dividends and other capital management transactions) and judgement about the application of existing tax laws in each jurisdiction. One of the Target Companies, SUGL, has received confirmation from the Nigerian Investment Promotion Commission and the Federal Internal Revenue Service that Pioneer Relief applies for a minimum of three years.

To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Target Companies to realise the net deferred income tax assets recorded at the reporting date could be impacted.

Pioneer status considerations

During 2014, SUGL received approval from the Nigerian Investment Promotion Commission ("**NIPC**") for its application for Pioneer Status under the terms of the Industrial Development (Income Tax Relief) Act. Under the terms of the approval, SUGL is exempt from Petroleum Profits Tax, Companies Income Tax and Education Tax for an initial period of 3 years (commencing February 01, 2014) with the option to apply for an extension of up to 2 years at the end of this initial period, and is able to defer capital allowances until after the tax exempt period. Although SUGL has received formal confirmation from the NIPC that Pioneer Status has been granted, the NIPC has not yet fully completed the associated documentation.

Accugas also submitted an application to the NIPC for Pioneer Status during 2014. If granted, Accugas will be exempt from Companies Income Tax and Tertiary Education Tax for a minimum period of three years which may be extended by a further two years upon filing an application; and is able to defer capital allowances until after this tax-exempt period. While Accugas has received verbal confirmation from the NIPC that Pioneer Status will be granted, the NIPC has not yet completed formal documentation. Accugas is also eligible for similar relief under incentives to the gas industry contained in the Companies Income Tax Act.

Key sources of estimation uncertainty

5.7 *Hydrocarbon reserve and resource estimates*

Oil and gas production properties are depreciated on a units of production basis at a rate calculated by reference to total proved and probable developed and undeveloped reserves determined in accordance with Society of Petroleum Engineers rules and incorporating the estimated future cost of developing those reserves.

The Target Companies estimate their commercial reserves based on information compiled by appropriately qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil or gas in place, recovery factors and future oil and gas prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of applicable contractual arrangement.

Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. As the economic assumptions used may change and as additional geological information is produced during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Target Companies' reported financial position and results which include:

- The carrying value of exploration and evaluation assets, oil and gas properties, property, plant and equipment, and goodwill may be affected due to changes in estimated future cash flows.
- Depreciation and amortisation charges in statement of profit or loss and other comprehensive income may change where such charges are determined using the units of production method, or where the useful life of the related assets change.
- Provisions for decommissioning may change – where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities.
- The recognition and carrying value of deferred income tax assets may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets.
- Condensates, a by-product of gas production are sold with crude oil.

5.8 *Useful lives of property, plant and equipment*

Management of the Target Companies review the estimated useful lives of property, plant and equipment at each balance sheet date. In assessing the useful lives of property, plant and equipment, and ancillary facilities, management considers, amongst other things, the expected usage of the assets by the Target Companies and the terms of relevant sales and purchase agreements. Any changes in estimates of the remaining useful lives of fixed assets will result in a higher or lower level of depreciation expense in future periods.

5.9 *Upstream and infrastructure oil and gas assets*

Management is required to assess the Target Companies' intangible assets and the upstream and infrastructure oil and gas assets for indicators of impairment. Notes 16 and 17 disclose the carrying values of such assets together with details of impairment charges arising. Management takes into account the Target Companies' latest development plans and business strategies and applies judgement in determining the appropriate cash generating units for the purpose of applying the annual impairment assessment. Management compares the carrying value of these assets to the estimated net present value of the underlying oil and gas reserves and related future cash flows that could be generated from these reserves based upon estimates of future production, oil and gas prices, development costs and operating costs and applying a suitable pre-tax discount rate. The reserve estimates are management's best estimates, taking into consideration independent evaluations of the proved and probable reserves attributable to the Target Companies' economic interests using industry standard definitions and measurement techniques.

5.10 *Fair value measurement*

From time to time the Target Companies are required to determine the fair values of both financial and non-financial assets and liabilities e.g., when the entity acquires a business, or where an entity measures the recoverable amount of an asset or cash-generating unit (CGU). Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest. A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use. The Target Companies use valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Fair value hierarchy

Where the fair value of financial assets and financial liabilities recorded in the statement of financial position cannot be derived from active markets, their fair value is determined using valuation techniques including the discounted cash flow model. The inputs to these models are taken from observable markets where possible, but where this is not feasible, a degree of judgement is required in establishing fair values. The judgements include considerations of inputs such as liquidity risk, credit risk and volatility.

The fair value of cash and cash equivalents, accounts receivable and accounts payable is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At each year end presented, the fair value of these balances approximated their carrying value due to their short term to maturity.

5.11 *Decommissioning liabilities*

The Target Companies have decommissioning obligations in respect of certain of their oil and gas interests and related midstream infrastructure. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including changes to relevant legal and regulatory requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditure can also change in response to changes in reserves or changes in laws and regulations or their interpretation.

The extent to which a provision is recognised requires management to make judgements on the legal and constructive obligations at the date of decommissioning, estimates of the restoration costs, timing of work, long-term inflation and discount rates to be applied. As a result, there could be significant adjustments to the provisions established which would affect future financial results.

5.12 *Take-or-pay contracts*

The Target Companies make a long-term and short-term gas supply commitment in return for a commitment from customers to pay for minimum quantities, whether or not they take delivery. However, revenue will only be recognised upon delivery, and not simply by obligation to receive payment.

Since some customers may be unable to take the full volume at once, then delivery may be deferred to a later date until the expiration of the contract, with additional make-up volumes allowable.

Therefore, the expected timing and amount of revenue may change based on quantity delivered and make-up quantity taken.

5.13 *Oil/condensates production entitlement*

Lifting arrangements for oil produced in some of the Target Companies' operations are accounted for as joint operations such that each participant receives and sells its precise share of the overall production in each period.

Under the Target Companies' funding agreement with its JO partner, SINOPEC International Petroleum Exploration and Production Company Nigeria Limited (Sinopec), the Target Companies are entitled to 20 per cent. of the crude oil production after crude oil allocation to settle royalty and overriding royalty payable to the Federal Government of Nigeria and the lease holder respectively. Until cost recovery is reached. Thereafter, the Target Companies are entitled to receive 35 per cent. of the crude oil production after an allocation for royalty payments.

5.14 *Allocation basis between shared oil and gas costs*

Impact on depreciation and amortisation computation

Management applies judgement in determining the appropriate cost split between oil and gas assets for shared oil and gas expenditure. These shared costs are split in line with expenditure on these assets for the purpose of depreciation and amortisation computation.

6. Changes in accounting policies and disclosures

New and amended standards and interpretations

The Target Companies applied IFRS 9 and IFRS 15 for the first time in the financial year ended 31 December 2018. The nature and effect of the changes as a result of adoption of these new accounting standards are described overleaf:

6.1 *IFRS 9 Financial Instruments*

IFRS 9 Financial Instruments replaces IAS 39 Financial Instruments: Recognition and Measurement for annual periods beginning on or after 1 January 2018, bringing together all three aspects of the accounting for financial instruments: classification and measurement; impairment; and hedge accounting.

The Target Companies applied IFRS 9 retrospectively, with an initial application date of 1 January 2018. The Target Companies have not restated the comparative information, which continues to be reported under IAS 39. Differences arising from the adoption of IFRS 9 were recognised directly in retained earnings and other components of equity in the individual financial information of the respective entities.

The effects of adopting IFRS 9 as at 1 January 2018, were as follows:

	Reference	*1 January 2018 US$'000*
Trade receivables		(23,343)
Loan receivable from SEIL		(239)
Net assets	6.1.2	(23,582)
Total adjustment on equity:		
Retained earnings	6.1.2	(23,582)
		(23,582)

The nature of these adjustments is described in the notes below.

6.1.1 *Classification and measurement*

Under IFRS 9, debt instruments are subsequently measured at fair value through profit or loss, amortised cost, or fair value through OCI. The classification is based on two criteria: The Target Companies' business model for managing the assets; and whether the instruments' contractual cash flows represent 'solely payments of principal and interest' on the principal amount outstanding.

The assessment of the Target Companies' business model was made as of the date of initial application, 1 January 2018. The assessment of whether contractual cash flows on debt instruments are solely comprised of principal and interest was made based on the facts and circumstances as at the initial recognition of the assets.

The classification and measurement requirements of IFRS 9 did not have a significant impact to the Target Companies. The following are the changes in the classification of the Target Companies' financial assets:

- Trade and other receivables and loan receivable from SEIL classified as loans and receivables as at 31 December 2017 are held to collect contractual cash flows and give rise to cash flows representing solely payments of principal and interest. These are classified and measured as debt instruments at amortised cost beginning 1 January 2018.
- The Target Companies have not designated any financial liabilities as at fair value through profit or loss. There are no changes in classification and measurement for the Target Companies' financial liabilities.

In summary, upon the adoption of IFRS 9, the Target Companies had the following required or elected reclassifications as at 1 January 2018:

IAS 39 measurement category Loans and receivables	*IFRS 9 measurement category*	*1 January 2018 US$'000*
Cash and cash equivalents	Amortised cost	18,916
Trade and other receivables*	Amortised cost	63,892
Loan receivable from SEIL*	Amortised cost	13,146

* The change in carrying amount is a result of additional impairment allowance. See the discussion on impairment below.

6.1.2 Impairment

The adoption of IFRS 9 has fundamentally changed the Target Companies' accounting for impairment losses for financial assets by replacing IAS 39's incurred loss approach with a forward-looking ECL approach. IFRS 9 requires the Target Companies to recognise an allowance for ECLs for all debt instruments not held at fair value through profit or loss.

Upon adoption of IFRS 9, the Target Companies recognised additional impairment on the Target Companies' trade and other receivables and loan receivable from SEIL of US$23.6 million, which resulted in a decrease in retained earnings of US$23.6 million as at 1 January 2018.

Set out below is the reconciliation of the impairment allowances in accordance with IAS 39 to the opening loss allowances determined in accordance with IFRS 9:

	Allowance for impairment under IAS 39 as at 31 December 2017 US$'000	*Re-measurement US$'000*	*ECL under IFRS 9 as at 1 January 2018 US$'000*
Loans and receivables under IAS 39/Financial assets at amortised cost under IFRS 9	1,545	23,343	24,888
Loan receivable from SEIL under IAS 39/Financial assets at amortised cost under IFRS 9	–	239	239
	1,545	23,582	25,127

6.2 ***IFRS 15 Revenue from Contracts with Customers***

IFRS 15 supersedes IAS 11 Construction Contracts, and IAS 18 Revenue and related Interpretations. It applies, with limited exceptions, to all revenue arising from contracts with customers. IFRS 15 establishes a five-step model to account for revenue arising from contracts with customers and requires that revenue be recognised at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer.

IFRS 15 requires entities to exercise judgement, taking into consideration all the relevant facts and circumstances when applying each step of the model to contracts with their customers. The standard also specifies the accounting for the incremental costs of obtaining a contract and the costs directly related to fulfilling a contract. In addition, the standard requires extensive disclosures.

The Target Companies adopted IFRS 15 using the modified retrospective method of adoption with the date of initial application of 1 January 2018. Under this method, the standard can be applied either to all contracts at the date of initial application or only to contracts that are not completed at this date. The Target Companies elected to apply the standard to all contracts as at 1 January 2018.

The cumulative effect of initially applying IFRS 15 is recognised at the date of initial application as an adjustment to the opening balance of retained earnings. Therefore, the comparative information was not restated and continues to be reported under IAS 18 and related interpretations.

There are no material quantitative changes based on the adoption of IFRS 15 to the Target Companies' revenue but the qualitative discloses have been updated accordingly.

7. Revenue

Disaggregated revenue information

Set out below is the disaggregation of the Target Companies' revenue from contracts with customers:

Segments	*2018 US$'000*	*2017 US$'000*	*2016 US$'000*
Gas sales	79,756	102,267	90,417
Crude oil sales	13,816	15,617	11,425
Total revenue from contracts with customers	93,572	117,884	101,842
Timing of revenue recognition			
Crude oil transferred at a point in time	13,816	15,617	11,425
Sales of gas transferred over time	79,756	102,267	90,417
Total revenue from contracts with customers	93,572	117,884	101,842

There are no other revenue items outside IFRS 15. Gas sales represents deliveries made to the Target Companies' customers.

Revenue from oil sales relates to crude oil sold to Exxon Mobil. The Target Companies sell crude oil under a sales and purchase agreement with ExxonMobil Sales & Supply LLC (EMS&SLLC) at prevailing market prices. Gas pricing is determined through long-term bilateral gas sales agreements.

7.1 *Contract balances*

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Trade receivables (Note 20)	87,900	75,723	57,211
Contract assets (Note 20)	6,463	–	–
Contract liabilities (Note 27)	125,059	72,229	62,224

Trade receivables are non-interest bearing and are generally on terms of 30 days.

Gas customers are invoiced under 'take-or-pay' contracts such that a minimum amount is invoiced irrespective of whether gas is delivered to the customer. The difference between the amount invoiced and the amount delivered, which is recognised as revenue in the income statement, is deferred as a Contract liability (or Deferred revenue) until this gas is delivered to the customer.

As a practical expedient provided in IFRS 15, the Target Companies decided not to disclose the amount of the remaining performance obligations for contracts with original expected duration of less than one year and contracts that meet the requirements of the right to invoice practical expedient.

Set out below is the portion of gas sold that was previously deferred in prior years now recognised as revenue in the reporting period:

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Amounts included in contract liabilities at the beginning of the year	3,682	11,205	4,875
	3,682	11,205	4,875

As a practical expedient provided in IFRS 15, the Company decided not to disclose the amount of the remaining performance obligations for contracts with original expected duration of less than one year and contracts that meet the requirements of the right to invoice practical expedient.

8. Cost of sales

	2018 US$'000	2017 US$'000	2016 US$'000
Cost of gas sold	15,300	19,306	26,029
Cost of oil sold	4,268	5,348	3,688
Depletion of oil and gas assets	37,383	41,105	42,191
	56,951	65,759	71,908

9. Other operating income/(expenses)

	2018 US$'000	2017 US$'000	2016 US$'000
Other income	13	3	3,199
Profit on asset disposal	–	5	–
Actuarial gain on long service award	3	–	–
Other operating costs	(54)	(1,143)	(209)
Time-writing recharges from related entities	(1,623)	(645)	(1,040)
Niger Delta Development Commission (NDDC) levy	(227)	(460)	5,143
	(1,888)	(2,240)	7,093

Net NDDC levy credit in 2016 mainly relates to a change in estimates based on new information from NDDC.

Other income in 2016 relates to the release of accruals no longer required.

10. Expected credit loss on financial assets

	2018 US$'000	2017 US$'000	2016 US$'000
Expected credit loss allowance and other receivable provision	15,543	–	1,698

The expected credit loss relates to impairment charge on financial assets on adoption of IFRS 9 (2018) and IAS 39 (2016 and 2017). See note 34.6 for further details.

11. Administrative expenses

	2018 US$'000	2017 US$'000	2016 US$'000
Depreciation and amortisation expenses	706	743	1,212
Time-writing recharges (to) / from related entities	(1,440)	(494)	863
Corporate allocations from related entities	9,710	5,333	7,514
Gross staff costs (note 11.1)	1,424	3,018	2,517
Directors' emoluments	135	145	148
Auditors' remuneration	153	228	294
Loss on Asset Disposal	4	–	–
Other administrative expenses	1,592	1,895	2,504
	12,284	10,868	15,052

No non-audit services were provided by the Auditors during the years presented.

Included in 2017 gross staff costs is an accrual of US$0.4 million relating to gratuity for employees who have spent five years or more in the Target Companies in line with the Collective Bargaining Agreement (CBA). The gratuity accrual was recognised on a discontinuance basis as the CBA between UERL and the workers' union expired on 28 February 2017. Renewed efforts by the workers' union led to a revised CBA signed on 5 December 2018.

11.1 ***Information regarding employees***

Average number of persons employed in the 2018 financial year was 31 (2017: 33, 2016: 35).

Gross employee remuneration is shown below:

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Wages and salaries	1,329	2,905	2,002
Termination payments	–	–	348
Pension costs	95	113	167
	1,424	3,018	2,517

12. Finance Income

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Inter group interest income (note 29.1)	2,927	3,888	3,772
Bank interest income	(49)	124	9
	2,878	4,012	3,781

Inter group interest income relates to interest earned on loan from SUGL to SEIL (see note 29.1).

Bank interest income relates to interest earned on deposits at various banks.

13. Finance Costs

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Interest on loans (other than those from related parties)	55,964	52,025	46,692
Interest on loans from related parties	21,916	26,332	31,926
Bank and other finance fees	15,319	15,369	8,846
Unwinding of discount on decommissioning provision (note 25)	2,258	2,107	2,166
Unwinding of discount on Uquo to Oron pipeline purchase	331	632	906
Interest cost on defined benefit obligation and long service award (note 27.4)	52	–	–
	95,840	96,465	90,536
Foreign exchange loss	6,799	5,796	–
	102,639	102,261	90,536

Unwinding of discount on Uquo to Oron pipeline relates to the difference between the cash price equivalent and the deferred consideration on Uquo to Oron line pipe purchase and recognised as an interest expense over the period of credit.

14. Taxation

14.1 *Tax expense recognised in profit or loss*

	2018 US$'000	2017 US$'000	2016 US$'000
Current tax			
Petroleum profits tax	–	–	–
Company income tax	–	–	–
Education tax	–	–	–
	–	–	–
Deferred tax			
(Charge)/credit for the year	(3,111)	63,404	108,664
Tax charge on other comprehensive gain	(91)	–	–
Total tax (expense)/ credit recognised in current year	(3,202)	63,404	108,664

The Target Companies did not have current tax charge for the years presented in respect of the Petroleum Profit Tax, Company Income Tax and Education Tax under the Petroleum Profit Tax Act CAP P13 LFN 2004, Companies Income Tax Act CAP C21 LFN 2004 as amended and Tertiary Education Trust Fund Act CAP EB, LFN 2011, as they had no taxable and assessable profits respectively for these years. Additionally, minimum tax provisions do not apply as each of the individual Group companies have more than 25 per cent. foreign equity.

14.2 *Deferred Tax*

The Target Companies had a deferred tax asset of US$265.2 million at the end of 2018 (2017: US$268.4 million, 2016: US$205 million). The amount primarily relates to tax losses and deferred capital allowances. These assets were recognised on the basis that future profits will be earned and these losses will be utilised. The movement in the deferred tax for the relevant years is as follows:

	2018 US$'000	2017 US$'000	2016 US$'000
At 1 January	268,438	205,034	96,370
Current year tax (expense) / credit	(3,111)	63,404	108,664
Tax charge on other comprehensive gain	(91)	–	–
At 31 December	265,236	268,438	205,034

Arising from:

	2018 US$'000	2017 US$'000	2016 US$'000
Tax losses	115,231	91,113	48,020
Deferred capital allowances	145,221	180,856	168,417
Others	4,784	(3,531)	(11,403)
	265,236	268,438	205,034

The tax credit for the year can be reconciled to the result per the Target Companies' statement of profit or loss and other comprehensive income as shown below:

	2018 *US$'000*	*%*	*2017* *US$'000*	*%*	*2016* *US$'000*	*%*
Profit/(loss) before tax	45,256		(59,232)		(297,572)	
Expected tax expense/(credit)	13,577	30	(17,770)	30	(89,272)	30
Actual tax expense/ (credit)	3,111	7	(63,404)	107	(108,664)	37
Difference	(10,466)	(23)	(45,634)	77	(19,392)	7
Analysed as:						
Effect of tax rate applicable to upstream E&P operations	3,225	7	(2,204)	4	(4,144)	1
Pioneer relief tax exemption	(8,381)	(19)	(8,363)	14	(10,911)	4
Expenses not deductible for tax purposes	1,649	4	2,253	(4)	18,665	2
Tax losses not recognised	–	–	–	–	9,168	(3)
Effect of higher tax rates in future years	(1,320)	(3)	(3,602)	6		–
Remeasurement of deferred tax assets	4,030	9	(28,748)	48	(22,451)	8
Decommissioning costs not recognised	804	2	698	(1)	2,632	(1)
Adjustment in respect of prior years	(11,758)	(26)	(6,318)	11	(12,690)	(4)
Other timing differences not recognised	1,285	3	650	(1)	339	–
	(10,466)	(23)	(45,634)	77	(19,392)	7

15. Property, plant & equipment

	Pipelines completed US$'000	Pipelines under construction US$'000	Other Infrastructure Assets US$'000	Upstream Assets US$'000	Movable & support assets US$'000	Total US$'000
Cost						
At 1 January 2016	651,224	57,379	239,758	287,280	5,472	1,241,113
Net additions/cost revision	(2,445)	34,872	(2,631)	(498)	238	29,536
Reclassifications	92,045	(92,045)	–	(6,805)	6,805	–
Adjustments	–	–	–	(2,112)	(102)	(2,214)
At 31 December 2016	740,824	206	237,127	277,865	12,413	1,268,435
Additions	7,726	138	4,341	3,194	12	15,411
Adjustments	–	–	–	553	–	553
Disposals	–	–	–	–	(248)	(248)
At 31 December 2017	748,550	344	241,468	281,612	12,177	1,284,151
Additions	3,145	150	1,679	2,054	739	7,767
Disposals	–	–	–	–	(495)	(495)
At 31 December 2018	751,695	494	243,147	283,666	12,421	1,291,423
Depreciation, depletion and impairment						
At 1 January 2016	184,533	–	37,316	47,721	3,377	272,947
Charge for the year	15,452	–	12,612	14,127	1,189	43,380
Impairment	180,989	–	62,575	9,930	–	253,494
At 31 December 2016	380,974	–	112,503	71,778	4,566	569,821
Charge for the year	16,668	–	7,124	18,709	723	43,224
Adjustments	–	–	–	(1,396)	–	(1,396)
Disposals	–	–	–	–	(241)	(241)
At 31 December 2017	397,642	–	119,627	89,091	5,048	611,408
Charge for the year	17,514	–	8,019	11,850	686	38,069
Disposals	–	–	–	–	(491)	(491)
Impairment reversal	(90,908)	–	(39,862)	(7,340)	–	(138,110)
At 31 December 2018	324,248	–	87,784	93,601	5,243	510,876
Net book value						
At 31 December 2018	427,447	494	155,363	190,065	7,178	780,547
At 31 December 2017	350,908	344	121,841	192,521	7,129	672,743
At 31 December 2016	359,850	206	124,624	206,087	7,847	698,614
At 31 December 2015	466,691	57,379	202,442	239,559	2,095	968,166

Adjustment in cost in 2016 relates to reconciliation of excess billings from the UERL Joint Operation with Sinopec, while adjustment in cost in 2017 relates to reversal of US$0.79 million exchange gain on SEPL loan previously used to reduce capitalised interest and reversal of US$0.23 million excess billings from the Joint Operation with Sinopec.

The adjustment in depreciation relates to prior year update on depletion amount due to new reserve figures and update on future development cost.

At 31 December 2018, the amount in pipelines under construction category relates to Calabar spurline project, which is aimed at delivering gas to last mile customers.

During 2018, capitalised decommissioning costs on the facilities and pipeline assets was US$6.2 million (2017: US$14.2 million, 2016: overall reduction of US$10.6 million) for future abandonment and restoration costs (see Note 26).

In 2018, management estimated the recoverable value of Group assets to be more than their carrying value. Hence an impairment provision reversal was made to the tune of US$138.1 million. The impairment reversal is primarily as a result of re-assessment of future cash flows from the assets. The reversal has been calculated by estimating the excess of the cash generating unit's recoverable amount over the carrying value. The impairment reversal recognised is limited to the impairment previously recognised, net of depreciation that would have occurred had no impairment been recognised initially.

The Target Companies have pledged their assets to secure their borrowings.

The Target Companies acted as a carrying party to their joint operation with Frontier Oil Limited ("FOL") during the years under review. The Joint Operating Agreement and the Technical Service Agreement provides that the Target Companies will recover their carried interest in the joint operation from oil and gas revenues. The total remaining amount expended by the Target Companies, which is recoverable from the joint operation as at year end 2018 was US$96.9 million (2017: US$101.8 million, 2016: US$109.9 million) and comprised of US$96.6 million (2017: US$101.6 million, 2016: US$109.5 million) of upstream assets and US$0.2 million (2017: US$0.2 million, 2016: US$0.4 million) of moveable & support assets.

16. Intangible assets

	Computer Software US$'000	*License US$'000*	*Total US$'000*
Cost			
At 1 January 2016	69	179	248
Additions	–	200	200
At 31 December 2016	69	379	448
Adjustments	–	(29)	(29)
At 31 December 2017	69	350	419
Additions	–	–	–
At 31 December 2018	69	350	419
Depreciation, depletion & amortisation			
At 1 January 2016	69	5	74
Charge for the year	–	23	23
At 31 December 2016	69	28	97
Charge for the year	–	20	20
At 31 December 2017	69	48	117
Charge for the year	–	20	20
At 31 December 2018	69	68	137
Net book value			
At 31 December 2018	–	282	282
At 31 December 2017	–	302	302
At 31 December 2016	–	351	351
At 31 December 2015	–	174	174

The license represents license acquired to produce crude from OML 14.

17. PPE disposed/written off in the statement of cash flows

	2018 US$'000	2017 US$'000	2016 US$'000
Cost of PPE disposed and written off	495	248	–
Accumulated depreciation on PPE disposed/written off	(491)	(241)	–
Carrying amount of PPE disposed/written off	4	7	–
Proceeds from disposal of property, plant and equipment	–	(12)	–
Loss/(profit) from sale of PPE	4	(5)	–

18. Other non-current assets

	2018 US$'000	2017 US$'000	2016 US$'000
Prepayments – take or pay gas	7,230	2,258	2,960
Stamp duty escrow account	192	1,242	1,457
	7,422	3,500	4,417

Prepayments – take or pay gas comprise of amount paid by the Target Companies to FOL for undelivered gas.

Stamp duty escrow account relates to funds required to be held on the Target Companies' borrowings until the discharge date of the borrowings (see note 24).

19. Inventories

	2018 US$'000	2017 US$'000	2016 US$'000
Materials	2,018	2,349	2,371
Crude oil stock (note 20.1)	851	826	1,484
	2,869	3,175	3,855

Materials are parts of a gas engine generator which will be used for spares and other operations.

19.1 ***Movement in Inventory (Crude oil stock)***

	2018 US$'000	2017 US$'000	2016 US$'000
Opening balance	826	1,484	1,875
Purchases	2,036	8,109	9,419
Available for sale	2,862	9,593	11,294
Amount sold	(2,011)	(8,767)	(9,810)
Closing balance	851	826	1,484

20. Trade and other receivables

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
Trade receivables			
Receivables from gas sales	83,631	68,065	47,640
Receivables from crude oil sales	963	1,087	1,850
Receivables from Joint Operation partners	3,306	6,571	7,721
Contract asset	6,463	–	–
	94,363	75,723	57,211
Inter group receivables (note 29)	6,708	3,409	2,511
Expected credit loss (Note 6.1 & 34.6)	(40,490)	(1,545)	(1,546)
	(33,782)	1,864	965
Other receivables			
WHT receivables	76	75	61
VAT receivables	9,071	9,439	5,847
Other receivables	85	134	143
	69,813	87,235	64,227

In 2016, the Target Companies recognised impairment loss of US$1.5 million relating to doubtful receivable from UERL/Sinopec JOT, a joint operations partner with Universal Energy Resources Limited. In 2018, the Target Companies recognised an additional impairment allowance of US$38.9 million due to the requirements of IFRS 9, that requires an expected impairment allowance be recorded on initial recognition of a financial asset.

Contract asset comprises of unbilled gas sold to customers at year end.

20.1 ***Trade receivables ageing***

The Directors consider that the carrying amounts of trade and other receivables are approximately equal to their fair value. The ageing of trade and other receivables at the end of the year that were not impaired are as follows:

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
Neither past due nor impaired	13,794	22,437	12,452
Past due 1-30 days	9,188	6,433	7,519
Past due 31-90 days	14,767	16,740	24,844
Past due 90+ days	32,064	41,625	19,412
	69,813	87,235	64,227

The Target Companies do not currently charge interest on past due receivables although in the event receivables become past due the Target Companies can do so at rates specified in the various agreements. The Target Companies periodically review all receivables outstanding to assess their recoverability. Set out below is the movement in the allowance for expected credit loss on trade receivables:

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
Balance as at 1 January under IAS 39	1,545	1,545	–
Adjustment upon application of IFRS 9	23,343	–	–
Balance as at 1 January as restated	24,888	1,545	–
Expected credit loss allowance	15,602	–	1,545
Balance at 31 December	40,490	1,545	1,545

21. Prepayment

Current Prepayments	*2018 US$'000*	*2017 US$'000*	*2016 US$'000*
Prepayments – take or pay gas	94	167	–
Other prepayments	3,334	1,449	2,192
	3,428	1,616	2,192

Prepayments – take or pay gas comprise of amount paid by the Target Companies to FOL for undelivered gas.

Other prepayments comprise of rent, insurance paid in advance and advances made to suppliers.

22. Cash and cash equivalents

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Cash in hand	1	1	1
Cash at bank	11,651	18,915	10,736
	11,652	18,916	10,737

Cash and cash equivalents comprise cash and short-term bank deposits with an original maturity of three months or less.

23. Trade and other payables

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Trade payables	31,642	31,396	34,344
Accruals	48,009	51,789	65,252
Inter group payables (note 29)	426,886	432,334	448,072
Interest payable	20,309	25,515	722
Other payables	19,381	26,949	18,382
	546,227	567,983	566,772

Trade payables primarily relate to amounts payable to gas suppliers and cash calls payable to FOL on the joint operation at the reporting date.

Other payables primarily relate to outstanding liabilities for gas tariff charges, line pipe purchases and construction costs for the Oron to Creek town pipeline project, royalty payable and NDDC levy payable.

24. Borrowings

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Secured borrowings			
Bank Loans			
Loans from non-related parties	395,237	397,762	404,405
Other loans			
Loans from related parties	423,839	401,387	374,800
Total gross borrowings	819,076	799,149	779,205
Unamortised finance costs incurred on raising debts	(2,624)	(9,187)	(21,754)
Total borrowings	816,452	789,962	757,451

	2018 US$'000	2017 US$'000	2016 US$'000
Current borrowings	799,899	765,523	655,095
Non-current borrowings	16,553	24,439	102,356
Total borrowings	816,452	789,962	757,451

The movement in borrowings for the relevant years is shown below:

	2018 US$'000	2017 US$'000	2016 US$'000
Opening Balance	789,962	757,451	755,820
Additions	13,182	13,385	27,000
Repayments	(13,182)	(17,228)	(50,195)
Reclassifications	26,287	36,354	24,826
Foreign exchange loss	203	–	–
Closing balance	816,452	789,962	757,451

The maturity profile of the Target Companies' borrowings including future interest expense on an undiscounted basis is shown in the table below. This differs from the carrying amounts and fair value due to the effect of discounting, future interest cost and unamortised finance fees. Interest expense on floating rate debt is adjusted based on the relevant US LIBOR rates.

	2018 US$'000	2017 US$'000	2016 US$'000
Current			
Amount due within one year	829,728	658,351	118,679
Amount due after one year but within two years	–	167,936	146,914
Amount due after two years but within five years	–	–	277,622
Non-current			
Amount due after one year but within two years	22,215	30,281	126,316
Amount due after two years but within five years	–	16,842	63,158
Amount due after five years	–	4,210	21,052
	851,943	877,620	753,741

Loans from non-related parties

Accugas IV

In July 2010, the Target Companies entered into a Project Finance Facility agreement of US$60.0 million with two financial institutions to finance the development of a gas transportation pipeline, processing facilities and related infrastructure. As at 31 December 2013, US$55.0 million had been drawn under this facility. The loan, which was secured by a charge over the pipeline and processing facilities being constructed, had an eight-year term with interest at the rate of 3-month US$ LIBOR plus 8 per cent. per annum, reducing to 7 per cent. per annum twelve months after completion of the development. The drawn down amount was repayable in quarterly instalments of variable amounts commencing in February 2013.

On 27 March 2013, the Target Companies signed the deed of amendment and restatement agreement on the existing US$60.0 million facility with an increased syndicate of Nigerian banks for US$225.0 million to include the Calabar infrastructure development. The revised US$225.0 million debt facility had a 7-year term with interest at the rate of 3-month US LIBOR plus 10.0 per cent. per annum and was repayable in quarterly instalments from March 2015. US$190.0 million was drawn down in 2013 while the balance of US$35.0 million was drawn in 2014.

On 28 March 2014, the Target Companies signed an Acquisition Finance Facility Agreement of up to US$170.0 million with three financial institutions for on-lending to SEIL to finance the acquisition of

100 per cent. of the issued share capital of EHGC. The facility had a five-year term with interest of US LIBOR plus 9.15 per cent. and was repayable in quarterly instalments from March 2015.

On 27 July 2015, the Target Companies refinanced the Project Finance and Acquisition Finance facilities into a single, combined facility of up to US$445.0 million ("**Accugas IV Facility**"), US$385.0 million of which had been initially drawn being US$225.0 million that had been previously drawn on the Project Finance Facility and US$160.0 million on the Acquisition Finance Facility. The Accugas IV 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.

In 2016, the Target Companies completed the final documentation with Accugas IV Facility lenders to revise the amortisation profile of the Accugas IV Facility, reducing the near-term debt service obligations in 2016 and 2017.

In 2018, a term sheet was signed with the Accugas IV Facility lenders which is a commitment to restructure existing US$370.8 million facility with a final maturity date extended to December 2025. The outstanding principal of the facility at 31 December, 2018 was US$370.8 million (31 December, 2017: US$373.1 million, 31 December, 2016: US$374.6 million).

Due to liquidity constraints the debt servicing obligations were not met as at year end and certain financial covenants had been breached. Therefore, the Target Companies were not in compliance with their loan obligations and the long-term balance of the outstanding loan has been disclosed within current borrowings – scheduled repayments after one year.

GuarantCo

On 29 December 2016, the Target Companies entered into a US$50 million debt service guarantee facility with GuarantCo Ltd ("**GuarantCo**") (the "**DSA Facility**"). In the event of liquidity constraints, the DSA Facility enables the Target Companies to meet up to US$50 million of its debt service obligations in respect of the US$385 million senior secured term facility dated 23 June 2015 (the "**Term Facility**"). The DSA Facility also eliminates the requirement under the Term Facility to maintain a debt service reserve account ("**DSRA**"), thereby releasing the US$5 million previously held in the DSRA which provided further liquidity to the Target Companies.

With the consent of GuarantCo and the Accugas IV Facility lenders, it was agreed that Accugas would draw the full US$11.3 million immediately available under the DSA Facility in order to make the interest and principal repayment due on the Term Facility on 31 December 2016.

Due to liquidity constraints, the debt servicing obligations were not met at year end and certain financial covenants had been breached. Therefore, the Target Companies were not in compliance with its loan obligations and the long-term balance of the outstanding loan has been disclosed within current borrowings – scheduled repayments after one year.

FBN Quest Merchant Bank

On 7 October 2015, SEIL, through the Target Companies, entered into a four-year Naira denominated working capital facility agreement with FBNQuest Merchant Bank (formerly Kakawa Discount House Limited) in the amount of ₦6 billion (2015: US$30.2 million). See further details in note 29.1.

Loans from related parties

AKIICORP Loan

In July 2006, the Target Companies' loan liability to United Bank for Africa (valued at $12.5 million) was paid for and taken over by Akwa Ibom Investment and Industrial Promotion Council (AKIICORP), an agency of the Akwa Ibom State Government and equity shareholder in UERL. As at the date of loan take over, the loan was not interest bearing, however in line with the requirements of IFRS, specifically, IFRS 13 – Fair value measurement, the Directors have adjusted the nominal value of the financial liability using the effective interest rate of 15 per cent. and repayment plan based on the probable date of first oil in line with the loan agreement between UERL, Seven Exploration and Production limited and AKIICORP.

As at the reporting date, the Target Companies were in breach of the loan agreement due to non-payment of principal and interest repayment obligations falling due to the lender. The entire loan becomes payable on demand (i.e. right of acceleration) in line with the agreement signed with AKIICORP, hence, the Directors have classified the entire loan as falling due within one year. However, in line with the payment plan agreed with AKIICORP, the Target Companies had paid a total of US$3 million as at the date of the financial information. The loan is not backed up by any collateral security.

SEPL Loan

Seven Exploration and Production Limited (SEPL) (the lender), made available to the Target Companies, a US$30 million secured term loan facility, for the purpose of developing Stubb creek field in accordance with the approved loan plan and budget. The loan is at an annual interest rate of LIBOR + 9 per cent. and has a tenure of 48 months from First Commercial Production. The loan is not backed by any collateral security.

Sequel to the resolution passed by management, evidencing the intent to borrow funds from SEPL for the purpose of meeting asset development obligations on Stubb creek project, amounts made available by SEPL under intercompany current account terms were reclassified to loan account. Accrued borrowing cost on this facility were capitalised as part of asset development cost before the assets became available for use and expensed thereafter in line with the provisions of IAS 23.

As at the reporting date, the Target Companies were in breach of the loan agreement due to non-payment of principal and interest repayment obligations falling due to the lender. The entire loan becomes payable on demand (i.e. right of acceleration) in line with the agreement signed with SEPL, hence, the directors have classified the entire loan as falling due within one year. However, no notice of acceleration has been received from SEPL as at the date of the financial information. The loan's carrying value, having become payable on demand, is deemed equal to its nominal value in line with the provisions of IFRS 13 and has been so presented.

25. Decommissioning provisions

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
At 1 January	58,816	42,532	50,944
Utilised during the year	–	–	(210)
Provided during the year	5,687	11,493	–
Change in estimate	531	2,684	(10,368)
Unwinding of decommissioning provision discount	2,258	2,107	2,166
At 31 December	67,292	58,816	42,532

The Target Companies provide for the present value of estimated future decommissioning costs for certain of its oil and gas properties in Nigeria. These costs are updated annually based upon a full technical assessment by internal and external specialists. The amounts shown are expected to crystallise between 2028 and 2046.

Assumptions based on the current economic environment have been made which management believes are a reasonable basis upon which to estimate the future abandonment and restoration liability. These estimates are reviewed regularly to take into account any material changes to the assumptions. However, actual decommissioning costs will ultimately depend upon future market prices for the necessary decommissioning works required which will reflect market conditions at the relevant time. Furthermore, the timing of decommissioning is likely to depend on when the fields cease to produce at economically viable rates. This, in turn, will depend upon future oil and gas prices, which are inherently uncertain.

26. Contract liability

Contract liability represents the value of gas supply commitment to the Target Companies' customers for gas not taken but invoiced under the terms of the contracts. The amount has been analysed between current and non-current liability, based on the customers' expected future usage gas delivery profile. This expected usage is updated periodically with the customer.

	2018 US$'000	2017 US$'000	2016 US$'000
Amount due for delivery within 12 months	3,213	3,561	–
Amount due for delivery after 12 months	121,846	68,668	62,224
	125,059	72,229	62,224

The Target Companies did not adjust the promised amount of consideration for the effects of financing components given the timing of the transfer of the gas is at the discretion of the customers.

	2018 US$'000	2017 US$'000	2016 US$'000
Opening balance	72,229	62,224	76,244
Net additions/adjustments	56,512	21,613	(7,823)
Recognised as revenue	(3,682)	(11,608)	(6,197)
Closing balance	125,059	72,229	62,224

In 2016, negotiation of the Take or Pay contract provisions with Ibom Power Company (IPC) from 40 MMscfpd to 20 MMscfpd resulted in the reduction of accrued Take or Pay amount.

In 2018, the Daily Contractual Quantity (DCQ) with Niger Delta Power Holding Company (NDPHC) on the Calabar Independent Power Project (CIPP) was increased from 31 MMscfpd to 131 MMscfpd based on the new Gas Sales Agreement with the Company.

27. Employee Benefits

	2018 US$'000	2017 US$'000	2016 US$'000
Present value of defined benefit obligation	313	–	–
Present value of long service awards	11	–	–
	324	–	–

27.1 ***Movement in present value of the defined benefit obligation***

	2018 US$'000	2017 US$'000	2016 US$'000
Past service cost – DBO (Opening)	369	–	–
Current service cost	66	–	–
Benefit paid by the plan	(66)	–	–
Interest expense on obligation	51	–	–
Actuarial gain recognised in other comprehensive income	(107)	–	–
	313	–	–

27.2 ***Movement in present value of the long service award***

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Past service cost – DBO (Opening)	12	–	–
Current service cost	2	–	–
Benefit paid by the plan	(1)	–	–
Interest expense on obligation	1	–	–
Actuarial gain recognised in income statement	(3)	–	–
	11	–	–

The Target Companies, through UERL, operate a defined benefit gratuity scheme per Collective Bargaining Agreement dated 5 December 2018. According to the scheme an employee who has served the Target Companies and is disengaging from service is entitled to end of service benefit. The most recent actuarial valuations of the present value of the defined benefit obligation were carried out for the year ended 31 December 2017 and 31 December 2018 by Ernst & Young (The Valuation Report was signed by Partner with Financial Reporting Council (FRC) Number 00000000738).

27.3 ***Expense recognised in the income statement for Long Service Award***

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Past service cost	12	–	–
Current service cost	2	–	–
Net actuarial gain	(3)	–	–
	11	–	–
Interest expense on obligation	2	–	–
	13	–	–

27.4 ***Total expense recognised in the income statement for Long Service Award***

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Past service cost – DBO (Opening)	381	–	–
Current service costs	68	–	–
Net actuarial gain on long service award	(3)	–	–
	446	–	–
Interest expense	52	–	–
	498	–	–

27.5 ***Funded Status***

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Defined Benefit Obligation	(313)	–	–
Long Service Award	(11)	–	–
Net balance sheet (liability)/asset	(324)	–	–

The Defined Benefit Obligation (Gratuity) and Long Service Award scheme are unfunded.

Actuarial gain recognised in other comprehensive income

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Gain on actuarial valuation of defined benefit obligation	(107)	–	–
Tax effect on other comprehensive income	(91)	–	–
	(198)	–	–

27.6 ***Actuarial assumptions***

Principal actuarial assumptions at the reporting date

Average Long-Term Future:	*2018*	*2017*	*2016*
Discount Rate (p.a.) -DBO & LSA	15.50%	–	–
Rate of Salary Increase (p.a.) -DBO	13.00%	–	–
Rate of Inflation (p.a.) -DBO & LSA	11.00%	–	–
Benefit Escalation rate -LSA	6.00%	–	–

These assumptions depict management's estimate of the likely future experience of the Target Companies. In order to measure the liability, the projected benefit must be discounted to a net present value as at the current balance sheet date, using an interest assumption (called the discount rate),

The discount rate should be determined on the Target Companies' balance sheet date by reference to market yields on high quality corporate bonds (except where there is no deep market in such bonds, in which case the discount rate should be based on market yields on Government bonds). The discount rate should reflect the duration of the liabilities of the benefit programme.

The Target Companies calculated the weighted average liability duration and adopted the corresponding Nigerian Government bonds market yield at the valuation date. The weighted average liability duration for the Plan is 10.13 years. The average weighted duration of the longest Nigerian Government bond as at 31 December 2018 was 5.96 years with a gross redemption yield of 15.29 per cent.

The Target Companies have prudently adopted a discount rate of 15.5 per cent. for the current valuation.

Mortality in Service

Due to unavailability of published reliable demographic data in Nigeria, the demographic assumptions regarding future mortality are based on the rates published in the A67/70 Ultimate Tables, published jointly by the Institute and Faculty of Actuaries in the UK.

Sample age	*Number of deaths in year of age of 10,000 lives*
25	7
30	7
35	9
40	14
45	26

Withdrawal from Service Age Band	*Rate*
Less than or equal to 30	3.0%
31 – 39	2.5%
41 – 44	2.0%
45 – 54	1.0%

Sensitivity analysis

Reasonably possible changes at the reporting date to one of the relevant actuarial assumptions holding other assumptions constant would have affected the defined benefit obligation by the amounts shown below:

		End of Service Benefit US$'000	*Long Service Award US$'000*
Base Rate		313	11
Discount Rate			
+1%		283	11
	-1%	346	12
Salary Increase Rate			
+1%		348	12
	-1%	281	11
Mortality Experience			
up by 1 year	Age rated	313	11
down by 1 year	Age rated	312	11

28. Non-controlling interests

The non-controlling interest relates to the remaining 37.5% shareholding in Universal Energy Resources Limited. The following table summarises the information relating to UERL, before any intra-group eliminations:

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Non-current assets	97,147	91,464	79,567
Current assets	9,072	7,560	6,569
Current liabilities	(62,936)	(61,661)	(58,390)
Non-current liabilities	(3,812)	(1,994)	(1,520)
Net assets	39,471	35,369	26,226
Net assets attributable to NCI	14,803	13,264	9,835

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Revenue	11,362	10,242	5,012
Profit / (loss) for the year	4,093	9,143	(4,493)
OCI	16	–	–
Total comprehensive income	4,109	9,143	(4,493)
Profit allocated to NCI	1,535	3,429	(1,685)
OCI allocated to NCI	6	–	–
Cash flows from operating activities	2,861	3,273	560
Cash flows from investing activities	(708)	(43)	(1,181)
Cash flows from financing activities (dividends to NCI: nil)	–	–	–
Net increase (decrease) in cash and cash equivalents	2,153	3,230	(621)

29. Inter group transactions

Related parties include the related companies, the directors, their close family members and any employee who is able to exert significant influence on the operating policies of the Target Companies. Key management personnel are also considered related parties. Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the entity, directly or indirectly, including any director (whether executive or otherwise) of that entity.

The Target Companies consider two parties to be related if, directly or indirectly one party has the ability to control the other party or exercise significant influence over the other party in making financial or operating decisions. Where there are related party transactions with the Target Companies, the transactions are disclosed separately as to the type of relationship that exists with the Target Companies and the outstanding balances necessary to understand their effects on the financial position and the mode of settlement.

During the year, the Target Companies comprising Accugas, SUGL, UERL and Exoro entered into transactions with related parties who are members of the larger Seven Group.

The amounts outstanding are unsecured and will be settled in the normal course of business or pursuant to the Implementation Agreement entered into to complete the Transaction. However, in line with IFRS 9, impairment loss on the related party receivables have been taking into consideration using the expected credit loss approach, where material. No guarantees have been given or received. The amounts due to / from related parties are not interest bearing. The related party payables have no fixed repayment period.

The following balances were due to/from related parties as at the end of the relevant financial years.

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
Due from related parties			
Seven Exploration and Production Limited	6,473	3,195	2,362
Energy 905 Suntera Limited	116	101	55
Gas Transmission & Power Limited	44	44	40
Ekid Gas Processing Company Limited	27	23	19
Exoro Energy Nigeria Limited	17	17	15
Domestic Gas Marketing Company Limited	21	19	14
Septa Oil Trading Company Limited	10	10	6
	6,708	3,409	2,511

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
Due to related parties			
Seven Energy International Limited	411,456	413,519	421,860
Seven Exploration & Production Limited	10,189	14,698	23,778
Seven Energy (UK) Limited	5,241	4,117	2,434
	426,886	432,334	448,072

Receivables from Seven Exploration and Production Limited relate to funding, timewriting and admin cost recharges while receivables from other related parties primarily relate to funding provided to the entities.

Payables to Seven Energy International Limited relate to funding, and corporate allocation.

All other transactions within the related parties primarily relate to intercompany funding.

Loans from related parties

On 29 October 2015, with an effective date of 30 June 2014, Accugas entered into a loan agreement with SEIL in which SEIL provided the sum of US$210.5 million to Accugas. No repayments of principal have been made since inception.

The loan bears no interest, however, in line with the requirement of IFRS 13 - fair value measurement, the Directors adjusted the nominal value of the financial liability to the fair value using an effective interest rate of 10.3 per cent., an approximate rate of the Accugas IV loan. Total finance costs for the year 2018 was US$4.4 million (2017: US$7.1 million, 2016: US$7.1 million). In line with IFRS 13 and IAS 39 (IAS 39 now IFRS 9), the difference between the fair value of loan on day one and the nominal value of US$62.2 million as at 31 December 2018 was classified as a loan discount reserve in Other reserves.

Prior to the merger of EHGC with Accugas, EHGC had a loan payable to SEIL for the settlement of EHGC's liabilities to its previous parent company at acquisition. At 31 December 2018, the outstanding principal was US$116.2 million (2017: US$116.2 million) and total interest charged on the loan during the year was US$12.9 million (2017: US$12.9 million). The loan bears interest at the rate of 3 months US$ LIBOR plus 9.15 per cent. per annum with first repayment in April 2016 and repayable thereafter on quarterly instalments from June 2016 until October 2021. Although no payments were made in accordance with the amortisation schedule, the Target Companies continue to accrue interest at the agreed interest rate.

29.1 ***Intergroup loan receivable***

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Loan to Seven Energy International Limited	13,182	13,385	15,700
Expected credit loss on loan receivable	(179)	–	–
	13,003	13,385	15,700

Set out below is the movement in the allowance for expected credit losses on loan receivable from SEIL:

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
As at 1 January	–	–	–
Provision for expected credit losses	179	–	–
As at 31 December	179	–	–

On 7 October 2015, SEIL, through SUGL, entered into a four-year Naira denominated working capital facility agreement with FBNQuest Merchant Bank (formerly Kakawa Discount House Limited) in the amount of ₦6 billion (2015: US$30.2 million). The facility currently bears interest at NIBOR plus 5 per cent. per annum (up to October 2016: 4 per cent.) and requires a mandatory full repayment of outstanding principal annually. At 31 December 2018, the outstanding balance of the loan being ₦4.8 billion (US$13.2 million) (2017: ₦4.8 billion (US$13.4 million), 2016: ₦4.8 billion (US$15.7 million)) has been lent to SEIL on identical terms and has been recognised as an related party loan receivable. The interest has therefore been recharged to SEIL as related party interest income (see note 12).

29.2 ***Remuneration of key management personnel***

The remuneration of the directors, who are the key management personnel of the Target Companies, is set out below in aggregate for each of the categories specified in IAS 24 Related Party Disclosures.

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Directors' Emoluments			
Fees	2	32	39
Other short-term benefits	133	113	109
	135	145	148

No dividend was paid or proposed to be paid in the year in respect of ordinary shares held by the Target Companies' directors.

Directors' emoluments relate to the Directors of UERL, who are all Non-Executive Directors. No remuneration was paid to the Directors of SUGL and Accugas for the three years presented.

30. Guarantees and other financial commitments

FOL and the Target Companies entered into a Memorandum of Understanding dated 20 September 2018 (the "**MOU**"). The MOU provides, amongst others, the agreement of the parties for a change in the commercial as well as economic interest of the parties in respect of the Uquo Marginal Field, and modalities for the Target Companies' payment of overdue payables. The change in both commercial and economic terms will result in the Target Companies paying FOL approximately $34.1 million as an advanced Cash Call to fund oil development. On 31 December 2019 the agreement was executed and payment made of $20 million.

This was finally executed on 31 December 2019.

The shares of Accugas have been pledged as security for the Accugas IV loan, while the shares of SUGL have been pledged as security for Seven Energy Finance Limited's (a subsidiary of the Seven Group) 10.25 per cent. senior secured notes.

31. Contingent liabilities

31.1 *Pending litigation and claim*

The Target Companies are involved in a law suit in which there are contingent liabilities of about US$2.7 million against them in the normal course of business. Although the suit is on-going, the Target Companies' legal advisers are of the view that the claim is without merit.

The Target Companies are also involved in a legal suit with Admiral Integrated Services Limited in which there is a contingent liability of about US$1.645 million against them in the normal course of business. Judgment was delivered in favour of Admiral to the tune of US$1.263 million plus 5 per cent. interest from judgment date till payment and ₦l00,000 cost of litigation. The Target Companies have however appealed against the judgement.

Although the appeal is ongoing, the legal advisers estimate that a future outflow of cash is probable. Consequently, a provision of US$400,000 have been made by the UERL/Sinopec JV which represents the Directors' assessment of the likely liability that may arise from this claim. The Target Companies have recognised 20 per cent. of this provision in this financial information in accordance with the JV Agreement with Sinopec.

FOL as the operator of the Joint Operation on the Uquo Field is involved in legal suits in which there are contingent liabilities of about US$ 0.1 million against it in the normal course of operation. Although the suits are on-going, the legal advisers estimate that the future outflow of cash is probable but cannot be reliably estimated as at the time of preparing the financial information. The Directors have not made any provision for these contingent liabilities in the financial information.

In June 2015, the Joint Operation obtained a license extension for 20 years from March 2015 without any renewal fees. However, in 2016, the Department of Petroleum Resources (DPR) issued a letter to Uquo Field Joint Operation for a 10-year extension with renewal fee of $1.0 million based on new government policy. The Directors believe the 20-year license is in line with section 19 of the Marginal Field guideline (2001) which has not been cancelled and the policy cannot be retrospectively applied. In view of this, the operator of the Joint Operation, FOL, communicated her objection to DPR and no response has been obtained as at the date of issuing the financial information. The Directors have therefore not made any provisions for these contingent liabilities in the financial information.

31.2 *Financial commitments*

The Directors are of the opinion that all known liabilities and commitments, which are relevant in assessing the state of affairs of the Target Companies, have been taken into consideration in the preparation of the financial information.

32. Capital risk management

The Target Companies' policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain the confidence of investors and Directors.

The Target Companies manage their capital to achieve the following:

- Maintain financial position strength in order to meet the Target Companies' strategic growth objectives; and
- Ensure financial capacity is available to fund the Target Companies' distribution commitments.

The capital structure of the Target Companies consists of equity attributable to equity holders of the Target Companies, comprising issued capital, reserves and retained earnings. The Target Companies are not subject to any externally imposed capital requirements.

33. Financial instruments

33.1 *Significant accounting policies*

Details of the significant accounting policies and methods adopted (including the criteria for recognition, the basis of measurement and the bases for recognition of income and expenses) for each class of financial asset, financial liability and equity instrument are disclosed in note 4.

33.2 *Categories of financial instruments*

The following table summarises the Target Companies' financial instruments:

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Financial assets			
Trade and other receivables	60,742	77,796	58,380
Stamp duty escrow	192	1,242	1,457
Loan receivable from SEIL	13,003	13,385	15,700
Cash and cash equivalents	11,652	18,916	10,737
	85,589	111,339	86,274

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Financial liabilities at amortised cost			
Trade and other payables	543,716	550,618	562,348
Borrowings	816,452	789,962	757,451
	1,360,168	1,340,580	1,319,799

33.3 *Fair value of financial instruments*

The Directors consider that the carrying amounts of financial assets and financial liabilities recorded at amortised cost in the financial information approximate their fair values.

34. Financial risk management

34.1 *Financial risk management objectives*

The Seven Group monitors and manages financial risks relating to its operations through internal risk reports which analyses exposures by degree and magnitude of risks. These risks include market risk (including currency risk, fair value interest rate risk and price risk), credit risk, liquidity risk and cash flow interest rate risk. Risk management policies and systems are reviewed regularly to reflect the changes in market conditions and the Target Companies' activities.

The Board of Directors, via the Seven Group, reviews and agrees policies for managing each of these risks which are summarised below:

34.2 ***Foreign currency risk and sensitivity analysis***

Foreign currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. The Target Companies enter into transactions denominated in foreign currencies related to their financing and their day-to-day operations. As a result, the statement of financial position can be affected by movements in foreign exchange rates.

However, a significant portion of the Target Companies' operations are not impacted by changes in foreign currency exchange rates as a significant portion of their intercompany balances and a significant portion of their production costs and their revenue are denominated in US$. The Target Companies also engage in transactions in other currencies such as Euros and GBP, however these transactions are immaterial.

The Target Companies' exposures to foreign currency risk arise from:

Naira exposures

The Target Companies receive Naira from customers on US Dollar denominated receivables at a lower rate compared to the rate at date of recognising the receivables due to the volatility of the Naira to US Dollars in the exchange rate market. The Target Companies record foreign exchange losses as a result of these Naira receipts. The Target Companies also make payments in Naira for certain local operating costs. The Target Companies convert US$ into Naira in order to make the necessary payments.

The following table details the Target Companies' sensitivity to a 5 per cent. change in the US$ against the relevant foreign currencies, with all other variables held constant, on the Target Companies' equity and profit due to changes in the fair value of monetary assets and liabilities. Management believes that a 5 per cent. movement in either direction is reasonably possible at the reporting date. A positive number below indicates an increase in profit and equity where the US$ strengthens against the relevant currency. For a weakening of the US$ against the relevant currency, there would be an equal and opposite impact on profit and the balances below would be negative.

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
US Dollar strengthens by 5% against the Naira **profit / (loss)**	(2,108)	(209)	9,445
US Dollar weakens by 5% against the Naira **profit / (loss)**	2,108	209	(9,445)

Foreign currency denominated balances

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Cash and cash equivalents	3,327	12,849	3,599
	3,327	12,849	3,599
Financial liabilities:			
Trade and other payables	31,629	19,758	24,937
Borrowings	6,780	6,245	9,033
	38,409	26,003	33,970

Exchange rates: Year end 2018 – ₦364.14/US$1; 2017 – ₦358.62/US$1; 2016 – ₦305.73/US$1; Average 2018- ₦361.23/US$1; 2017 – ₦334.65/US$1; 2016 – ₦258.01/US$1.

34.3 *Interest rate risk management*

The Target Companies are exposed to cash flow interest rate risk through funds borrowed at floating interest rates. These exposures arise from the interest on the related party loan and third-party loan which are based on US LIBOR. Changes to the borrowing costs of the Target Companies are monitored by management and assessed relative to the Target Companies' ongoing cash flows from operations.

The sensitivity analyses have been determined based on the exposure to interest rates for financial instruments at the statement of financial position date. For floating rate liabilities, the analysis is prepared assuming the amount of liability outstanding at the statement of financial position date was outstanding for the whole year. A one percent increase or decrease represents management's assessment of the reasonably possible change in interest rates and is derived from the Seven Group's risk register which includes historical interest rate exposure.

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
1% Higher			
Borrowings	(8,165)	(7,900)	(7,575)
1% Lower			
Borrowings	8,165	7,900	7,575

34.4 *Commodity price risk management*

The Target Companies' activities expose them primarily to the financial risks of changes in oil and gas commodity prices. The Target Companies monitor and manage the risk through long-term sales contracts.

34.5 *Liquidity risk management*

Ultimate responsibility for liquidity risk management rests with the Board of Directors, via the Seven Group, which has built a liquidity risk management framework for the management of the Target Companies' short, medium and long-term funding and liquidity management requirements. The Target Companies maintain liquid reserves, by 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, and delays in development projects. On this basis, the Target Companies' forecasts, taking into account reasonably possible changes as described above, show that the Target Companies expect to be able to operate within their current debt facilities and have adequate resources to continue in operation for the foreseeable future.

The Target Companies' cash reserves are held in Nigeria. All of the Target Companies' cash and cash equivalents are currently held within reputable and well-known commercial institutions.

The following table details the Target Companies' 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 Target Companies can be required to pay.

	2018	*2017*	*2016*
	US$'000	*US$'000*	*US$'000*
≤ 30 days	113,993	110,714	98,041
61 – 90 days	429,723	433,523	464,307
	543,716	544,237	562,348

34.6 ***Credit risk management***

Credit risk is the risk that a counterparty will not meet its obligations under a financial instrument or customer contract, leading to a financial loss. The Target Companies are exposed to credit risk from their operating activities (primarily trade receivables) and from their financing activities, including deposits with Group's and financial institutions, foreign exchange transactions and other financial instruments.

Credit risk is monitored by the Board of Directors, via the Seven Group. It is their responsibility to review and manage credit risk, including environmental and social risk for all types of counterparties.

The Target Companies have established a credit quality review process to provide early identification of possible changes in the creditworthiness of counterparties, including regular collateral revisions. Counterparty limits are established by the use of a credit risk classification system, which assigns each counterparty a risk rating. Risk ratings are subject to regular revision. The credit quality review process aims to allow the Target Companies to assess the potential loss as a result of the risks to which it is exposed and take corrective actions.

Treasury, trading and intercompany relationships

The Target Companies' treasury, trading and intercompany relationships and counterparties comprise financial services institutions. For these relationships, the Target Companies analyse publicly available information such as financial information and other external data, e.g., the rating of Good Rating Agency, and assigns the internal rating, as shown in the table below:

Nigeria Mapping Table

Implied S&P rating class (without modifiers)	*Implied S&P rating categories (with modifiers)*
B	B+
B	B
B	B
B	B
B	B-
B	B-
CCC	CCC+
CCC	CCC
CCC	CCC-
CC	CC
C	C
D	D
D	D
D	D

Trade receivables

Customer credit risk is managed subject to the Target Companies' established policy, procedures and controls relating to customer credit risk management. The credit quality of a customer is assessed based on an extensive credit rating scorecard and individual credit limits are defined in accordance with this assessment. Outstanding customer receivables are regularly monitored and any delivery to major customers are generally covered by letters of credit or other forms of credit insurance obtained from reputable Group's and other financial institutions. An impairment analysis is performed at each reporting date using a provision matrix to measure expected credit losses. The provision rates are based on days past due for groupings of various customer segments with similar loss patterns (i.e., product type and customer type). The calculation reflects the probability-weighted outcome, the time value of money and reasonable and supportable information that is available at the reporting date about past events, current conditions and forecasts of future economic conditions. Generally, trade receivables are written-off if past due for more than one year and are not subject to enforcement activity.

The maximum exposure to credit risk at the reporting date is the carrying value of each class of financial assets disclosed in Note 20. The Target Companies do not hold collateral as security. The letters of credit and other forms of credit insurance are considered integral part of trade receivables and considered in the calculation of impairment.

Set out below is the movement in the allowance for expected credit losses of trade receivables:

	2018 *US$'000*	*2017* *US$'000*	*2016* *US$'000*
Balance as at 1 January under IAS 39	1,545	1,545	–
Adjustment upon application of IFRS 9	23,343	–	–
Balance as at 1 January as restated	24,888	1,545	–
Expected credit loss allowance	15,602	–	1,545
Write-off	–	–	–
Balance at 31 December	40,490	1,545	1,545

Analysis of inputs to the ECL model under multiple economic scenarios

An overview of the approach to estimating ECLs is set out in Summary of significant accounting policies. To ensure completeness and accuracy, the Target Companies obtain the data used from third party sources (Central Bank of Nigeria, Standards and Poor's etc.) and a team of experts within its credit risk department verifies the accuracy of inputs to the Target Companies' ECL models including determining the weights attributable to the multiple scenarios. The following tables set out the key drivers of expected loss and the assumptions used for the Target Companies' base case estimate, ECLs based on the base case, plus the effect of the use of multiple economic scenarios as at 31 December 2017 and 31 December 2018.

The tables show the values of the key forward looking economic variables/assumptions used in each of the economic scenarios for the ECL calculations. The figures for "Subsequent years" represent a long-term average and so are the same for each scenario.

31 December 2018

Key drivers EDTF 3	*ECL Scenario*	*2019*	*2020*	*2021*
Oil Price US$/Barrel				
	Upturn	53	55	56
	Base	56	56	52
	Downturn	48	50	52
Unemployment rate %				
	Upturn	17	15	13
	Base	18	18	17
	Downturn	20	19	17
Inflation rate %				
	Upturn	13	14	15
	Base	14	14	15
	Downturn	15	16	16

1 January, 2018

Key drivers EDTF 3	*ECL Scenario*	*2018*	*2019*	*2020*
Oil Price US$/Barrel				
	Upturn	56	55	53
	Base	51	50	54
	Downturn	48	50	52
Unemployment rate %				
	Upturn	13	14	17
	Base	18	17	15
	Downturn	20	19	17
Inflation rate %				
	Upturn	15	14	13
	Base	14	15	15
	Downturn	15	16	16

As at 31 December 2017, under IAS 39, no impairment charges were recorded in the statement of profit or loss.

The credit risk on liquid funds and non-derivative financial instruments is limited because the counterparties are banks with high credit-ratings assigned by international credit-rating agencies and related companies.

The carrying amount of financial assets represents the Target Companies' maximum exposure, which at the reporting date, was as follows:

	2018 US$'000	*2017 US$'000*	*2016 US$'000*
Financial assets			
Trade and other receivables	60,742	77,796	58,380
Stamp duty escrow	192	1,242	1,457
Loan receivable from SEIL	13,003	13,385	15,700
Cash and cash equivalents	11,652	18,916	10,737
Financial assets	85,589	111,339	86,274

The average credit period given on joint interest billings and oil and gas sales is 60 days. The Target Companies do not currently charge interest on past due receivables although in the event receivables become past due the Target Companies can do so at rates specified in the various agreements. The Target Companies periodically review all receivables outstanding to assess their recoverability.

34.7 *Impairment allowance for financial assets*

In assessing the Target Companies' internal rating process, the Target Companies' customers and counter parties are assessed based on a credit scoring model that takes into account various historical, current and forward-looking information such as:

- Any publicly available information on the Target Companies' customers and counter parties from external parties. This includes external rating grades issued by rating agencies, independent analyst reports, publicly traded bond or press releases and articles.

- Any macro-economic or geopolitical information, e.g., GDP growth relevant for the specific industry and geographical segments where the client operates.

- Any other objectively supportable information on the quality and abilities of the client's management relevant for the Target Companies' performance.

The table below shows the Target Companies' internal credit rating grades:

Internal rating grade	*Internal rating description*	*12-month PD range*	*Implied S&P* rating
1	High grade	0.00% – 0.58%	Very Good+
2	High grade	0.58% – 1.42%	Very Good
3	High grade	1.42% – 2.43%	Very Good-
4	Standard grade	2.43% – 16.3%	Good+
5	Standard grade	16.3% – 28.05%	Good
7	Sub-standard grade	28.05% – 41.03%	Average+
8	Past due but not impaired	41.03% – 100%	Bad
Non-performing			
9	Individually impaired	100%	Very Bad

Impairment allowance for trade receivables

The table below shows the credit quality and the maximum exposure to credit risk based on the Target Companies' internal credit rating system and year-end stage classification. The amounts presented are gross of impairment allowances.

Internal grading system *Performing*	*2018* *Stage 1* *Individual* *US$'000*	*2018* *Stage 3* *Individual* *US$'000*	*2018* *Simplify* *US$'000*	*2018* *Total* *US$'000*	*2017* *Total* *US$'000*
High grade	111	–	820	931	109
Standard grade	31,187	–	–	31,187	46,738
Sub-standard grade	55,510	–	–	55,510	17,985
Individually impaired	1,545	35	–	1,580	1,545
Total	88,353	35	820	89,208	66,377

An analysis of changes in the gross carrying amount and the corresponding ECL allowances in relation to trade receivables is, as follows:

	Stage 1 *Individual* *US$'000*	*Stage 3* *Individual* *US$'000*	*Total* *US$'000*
Gross carrying amount as at 1 January 2018	66,377	–	66,377
New assets originated or purchased	22,012	–	22,012
Assets derecognised or repaid (excluding write offs)	(1)	–	(1)
Transfers to Stage 3	(35)	35	–
Total	88,353	35	88,388

	Stage 1 *Individual* *US$'000*	*Stage 3* *Individual* *US$'000*	*Total* *US$'000*
ECL allowance as at 1 January 2018 under IFRS 9	24,888	–	24,888
New assets originated or purchased	15,574	35	15,609
Assets derecognised or repaid (excluding write offs)	(7)	–	(7)
Total	40,455	35	40,490

The increase in ECLs of the portfolio was driven by an increase in the gross size of the portfolio.

Impairment allowance for loan receivable from SEIL

The table below shows the credit quality and the maximum exposure to credit risk based on the Company's internal credit rating system and year-end stage classification. The amounts presented are gross of impairment allowances.

Internal grading system *Performing*	*2018* *Simplify* *US$'000*	*2017* *Simplify* *US$'000*
High grade	13,182	13,385

An analysis of changes in the gross carrying amount and the corresponding ECL allowances in relation to loan receivable from SEIL is as follows:

	Life time ECL *Individual* *US$'000*
Gross carrying amount as at 1 January 2018	13,385
New assets originated or purchased	13,182
Assets derecognised or repaid (excluding write offs)	(13,385)
At 31 December 2018	13,182

	Life time ECL *Individual* *US$'000*
ECL allowance as at 1 January 2018 under IFRS 9	239
New assets originated or purchased	179
Assets derecognised or repaid (excluding write offs)	(271)
Unwinding of discount	32
At 31 December 2018	179

The Target Companies monitor their risk of a shortage of funds using a liquidity planning tool.

34.8 ***Maturity analysis of trade receivables***

		31-Dec-18		*01-Jan-18*	
		Estimated total gross carrying amount at default US$'000	*Expected credit loss* US$'000	*Estimated total gross carrying amount at default* US$'000	*Expected credit loss* US$'000
Days past due	**Contract assets**	6,463	511	11,243	2,139
	Current	17,210	114	23,905	1,636
	<30 days	42	3	6,961	1,815
	30–60 days	6,593	1,520	1,003	355
	61–90 days	829	110	3,540	1,120
	91–270 days	42,523	17,529	16,864	5,616
	271–365 days	1,747	1,747	1,472	1,472
	>365 days	18,956	18,956	10,735	10,735
	Total	94,363	40,490	75,723	24,888

35. Events after the reporting period

As noted in Part 3 of the admission document, Risk Factors, the ongoing COVID-19 (coronavirus) pandemic could have a material adverse effect on the Target Companies' results of operations and financial condition.

On 9 August 2018, United Cement Group now known as Lafarge Africa Plc ("**Lafarge**"), one of Accugas' gas customers sent a letter described as a "Notice of a Hardship Event" (the Hardship Notice) stating that the economic recession in Nigeria which started in 2016 has resulted in a decline in economic activities in the country and by extension has led to a decline in Lafarge's capacity utilization to date. To mitigate this, they have suggested a contract renegotiation. Lafarge subsequently gave notice to Accugas on 25 February 2019 of its intentions to refer the matter to expert determination in accordance with the existing Natural Gas Sale and Purchase Agreement (NGSPA) between both parties. There is a dispute between the parties as to whether the Hardship Notice has been validly issued. Accugas' position is that Lafarge's Hardship Notice is not valid and its notice referring the matter to expert determination is premature as the Hardship claim is yet to be substantiated.

During the process of drafting the Terms of Reference for the Expert, Accugas expressed its concerns to Lafarge that the Expert determination process being initiated by Lafarge was premature given that parties had not held good faith discussions. Subsequently, parties recommenced good faith discussion to review the terms of the NGSPA for a mutually beneficial outcome (without prejudice to the Expert determination). On 15 April 2020, Lafarge sent a letter to Accugas disputing its certain invoices and purporting to unilaterally reduce its payment obligations under the NGSPA. Accugas believes that there is no legal or contractual basis for Lafarge's claim and responded to Lafarge's letter on 20 April 2020 vigorously defending its rights under the NGSPA.

PART 6C

HISTORICAL UNAUDITED INTERIM FINANCIAL INFORMATION ON THE TARGET COMPANIES

Consolidated statement of profit or loss and other comprehensive income for the six months ended 30 June 2019

	Notes	*6 months ended 30 June 2019 US$'000*	*6 months ended 30 June 2018 US$'000*
Revenue	1	70,271	60,585
Cost of sales	2	(13,927)	(11,329)
Gross profit		56,344	49,256
Depreciation, depletion and amortisation expenses		(26,308)	(20,524)
Other income	3	–	20
Net operating expenses	4	(779)	(616)
Expected credit loss on financial assets	5	(13,511)	(13,362)
Administrative expenses	6	(1,568)	(5,778)
Operating profit/(loss)		14,178	8,996
Finance income	7	1,422	1,371
Finance costs	8	(43,633)	(47,476)
Foreign exchange difference		(4,158)	(2,776)
Profit/(loss) before taxation		(32,191)	(39,885)
Tax (expense)/credit	9	35,567	12,562
Profit/(loss) for the period		3,376	(27,323)
Attributable to:			
Owners of the Group		3,376	(27,323)
Non-controlling interests		–	–
Other comprehensive income/(loss):			
Defined benefit plan actuarial gain		25	–
Total comprehensive income/(loss) for the period		3,401	(27,323)
Attributable to:			
Owners of the Group		3,401	(27,323)
Non-controlling interests		–	–

Consolidated statement of financial position as at 30 June 2019

	Notes	*At 30 June 2019 US$'000*	*At 31 December 2018 US$'000*
Non-current assets			
Property, plant and equipment		753,470	780,547
Intangible assets		252	282
Other non-current assets	13,14	8,921	7,422
Deferred tax asset		302,121	265,236
		1,064,764	1,053,487
Current assets			
Inventories	10	3,577	2,869
Trade and other receivables	13	102,133	69,813
Inter group loan receivables	11	12,759	13,003
Prepayments	14	5,063	3,428
Cash and cash equivalents	12	13,354	11,652
		136,886	100,765
Total assets		1,201,650	1,154,252
Current liabilities			
Borrowings	16	809,341	799,899
Trade and other payables	15	553,085	546,227
Contract liability	17	4,956	3,213
Total current liabilities		1,367,382	1,349,339
Non-current liabilities			
Borrowings	16	18,583	16,553
Contract liability	17	144,580	121,846
Employee benefits	18	353	324
Decommissioning provision		68,455	67,292
Total non-current liabilities		231,971	206,015
Total liabilities		1,599,353	1,555,354
Net liabilities		(397,703)	(401,102)

Consolidated statement of cash flows

	6 months ended 30 June 2019 US$'000	*6 months ended 30 June 2018 US$'000*
Profit/(loss) after tax	3,401	(27,323)
Adjustments for:		
Foreign exchange difference	4,158	2,776
Other income	–	–
Finance income	(1,422)	(1,371)
Finance costs	43,633	47,476
Depreciation, depletion and amortisation of property, plant and equipment	26,308	20,524
Expected credit loss on trade and intercompany receivables	13,511	13,362
Income tax expense/(credit)	(35,567)	(12,562)
Employee benefits	4	–
Operating cash flows before movements in working capital	54,026	42,882
Decrease/(increase) in inventory	(708)	505
Decrease/(increase) in trade and other receivables	(45,510)	(20,368)
Increase/(decrease) in trade and other payables	15,463	26,458
Net cash generated from operating activities	23,271	49,477
Investing activities		
Capital Expenditures	799	(1,280)
Finance income received	1,422	1,371
Net cash used in investing activities	2,221	91
Financing activities		
Proceeds from borrowings	13,333	13,333
Repayment of borrowings	(18,655)	(15,655)
Finance costs paid	(18,518)	(40,396)
Receipt from Share Capital Debtor	50	–
Net cash used in financing activities	(23,790)	(42,718)
Net (decrease)/increase in cash and cash equivalents	1,702	6,850
Cash and cash equivalents at 1 January	11,652	18,916
Cash and cash equivalents at 30 June	13,354	25,766

1 Revenue

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Gas sales	64,227	51,970
Crude oil sales	6,044	8,615
Total revenue from contracts with customers	70,271	60,585

2 Cost of sales

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Cost of gas sold	13,029	9,811
Cost of oil sold (note 2.1)	898	1,518
	13,927	11,329

2.1 *Cost of gas sold*

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Other production costs	11,244	8,438
Royalty	1,785	1,373
	13,029	9,811

2.2 *Cost of oil sold*

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Other production costs	670	1,107
Royalty	228	411
	898	1,518

3 Other income

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Other income	–	20
	–	20

4 Other operating expenses

	6 months ended 30 June 2019 US$'000	*6 months ended 30 June 2018 US$'000*
Other operating costs	(3)	18
Timewriting recharges from related entities	635	663
Niger Delta Development Commission levy	147	(65)
	779	616

5 Expected credit loss on financial assets

	6 months ended 30 June 2019 US$'000	*6 months ended 30 June 2018 US$'000*
Expected credit loss allowance	13,511	13,362

6 Administrative expenses

	6 months ended 30 June 2019 US$'000	*6 months ended 30 June 2018 US$'000*
Time-writing recharges from related entities	158	369
Corporate allocations from related entities	1,369	5,659
Time-writing recharges to related entities	(1,345)	(1,407)
Gross staff costs	419	594
Auditors' remuneration	(18)	(51)
Loss on Asset Disposal	–	4
Other administrative expenses	985	610
	1,568	5,778

7 Finance Income

	6 months ended 30 June 2019 US$'000	*6 months ended 30 June 2018 US$'000*
Related party loan interest	1,418	1,472
Bank interest income	4	(101)
	1,422	1,371

8 Finance Costs

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Interest on loans (other than those from related parties)	28,110	26,873
Interest on loans from related parties	11,572	10,229
Bank and other finance fees	2,763	9,256
Unwinding of discount on decommissioning provision	1,163	1,118
Interest cost on defined benefit obligation and long service award	25	–
	43,633	47,476

9 Taxation

	6 months ended 30 June 2019 US$'000	6 months ended 30 June 2018 US$'000
Current taxation	1,319	–
Deferred taxation	(36,886)	(12,562)
	(35,567)	(12,562)

10 Inventories

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Materials	2,012	2,018
Crude oil stock	1,565	851
	3,577	2,869

11 Inter group loan receivables

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Loan to Seven Energy International Limited	13,333	13,182
Expected credit loss on loan receivable	(574)	(179)
	12,759	13,003

12 Cash and cash equivalents

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Cash and cash equivalents	13,354	11,652
	13,354	11,652

13 Trade and other receivables

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Trade receivables		
Receivables from gas sales	108,994	83,631
Receivables from crude oil sales	934	963
Receivables from Joint Venture partners	4,266	3,306
Contract asset	21,316	6,463
	135,510	94,363
Due from related parties	7,876	6,708
Expected credit loss	(53,570)	(40,490)
	89,816	60,581
Other receivables		
WHT receivables	76	76
VAT receivables	12,241	9,071
Other receivables	–	85
	102,133	69,813

Amounts due from related parties are in respects of amounts owed by other members of the Seven Group.

Non current other receivables	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Stamp duty escrow account	194	192
	194	192

14 Prepayment

Current Prepayments	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Prepayments - take or pay gas	137	6,975
Other prepayments	4,926	1,617
	5,063	8,592
Non Current Prepayment		
Prepayments - take or pay gas	8,727	7,230
	8,727	7,230

15 Trade and other payables

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Trade payables	32,504	31,642
Accruals	40,440	48,009
Due to related parties	423,275	426,886
Interest payable	23,946	20,309
Other payables	32,920	19,381
	553,085	546,227

Amounts due to related parties are in respects of amounts owed to other members of the Seven Group.

16 Borrowings

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Current borrowings	809,341	799,899
Non-current borrowings	18,583	16,553
Total net borrowings	827,924	816,452
Loans from related parties	431,168	423,839
Loans from non-related parties	396,756	392,613
	827,924	816,452

Loans from related parties are in respects of amounts owed to other members of the Seven Group.

7 Contract liability

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Amount due for delivery within 12 months	4,956	3,213
Amount due for delivery after 12 months	144,580	121,846
	149,536	125,059

18 Employee Benefits

	At 30 June 2019 US$'000	At 31 December 2018 US$'000
Present value of defined benefit obligation	341	–
Present value of long service awards	12	–
	353	–

19 Non-controlling interests

	6 months ended 30 June 2019 US$'000	*6 months ended 30 June 2018 US$'000*
Profit/(loss) for the period attributable to non-controlling interests	–	–
Total comprehensive income/(loss) for the period attributable to non-controlling interests	–	–

PART 6D

HISTORICAL ANNUAL AND INTERIM FINANCIAL INFORMATION

OF THE EXISTING GROUP

In accordance with Rule 28 of the AIM Rules, this document does not contain historical financial information on the Existing Group, which would otherwise be required under Section 18 of Annex I of the AIM Rules.

This information is available on the Company's website, as follows:

Financial information	*Hyperlink*
Savannah's audited results for the year ended 31 December 2016	*https://www.savannah-energy.com/downloads/reports/Savannah-Annual-Report-2016.pdf*
Savannah's audited results for the year ended 31 December 2017	*https://www.savannah-energy.com/downloads/reports/Savannah-Annual-Report-2017.pdf*
Savannah's audited results for the year ended 31 December 2018	*https://www.savannah-energy.com/downloads/reports/SVP_AR18_web%20bookmarked.pdf*
Savannah's unaudited interim results for the six months ended 30 June 2019	*https://www.savannah-energy.com/downloads/releases/Savannah%20Petroleum%20PLC%20Interim%20Accounts%20H1%202019%20FINAL.pdf*

Shareholders or other recipients of this document may request a hard copy of the above information incorporated by reference from the Company at its registered office, 40 Bank Street, London, E14 5NR, or by telephoning +44 (0) 20 3817 9844. Such copy will be provided to the requester within 7 days. A hard copy of the information incorporated by reference will not be sent to Shareholders or other recipients of this document unless requested.

PART 7

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, Capital Restructuring, AIIM Transaction, FOL Transaction and other related adjustments on the net assets of the Company as if the Acquisition, Capital Restructuring, AIIM Transaction, FOL Transaction and other related adjustments had taken place on 30 June 2019. 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 has been prepared for illustrative purposes only and illustrates the impact of the Acquisition, Capital Restructuring, AIIM Transaction, FOL Transaction and other related adjustments as if they had been undertaken at an earlier date. As a result, the hypothetical financial position or results included in the unaudited pro forma financial information may differ from the Enlarged Group's actual financial position or results.

The unaudited pro forma statement of net assets of the Enlarged Group is based on the consolidated net assets of the Company as at 30 June 2019 as set out in the unaudited consolidated interim financial statements of the Group for the six months then ended.

The unaudited pro forma statement of net assets has been prepared in a manner consistent with the accounting policies adopted by the Group in preparing such information, in accordance with Annex 20 of the Prospectus Regulation and on the basis set out in the notes below.

Section B: Unaudited Pro Forma Statement of Net Assets of the Enlarged Group

	Existing Group	*Nigerian Assets*			*Adjustments*			*Pro forma*
	Note 1	*Note 2*	*Note 3*	*Note 4*	*Note 5*	*Note 6*	*Note 7*	
	US$000	*US$000*	*US$000*	*US$000*	*US$000*	*US$000*	*US$000*	*US$000*
Non-current assets								
Property, plant and equipment	2,454	753,470	292	–	–	–	–	756,216
Intangible assets	–	252	–	–	–	–	–	252
Right of use assets	4,319	–	–	–	–	–	–	4,319
Exploration and evaluation assets	152,513	–	–	–	–	–	–	152,513
Long term financial assets	96,816	–	(96,816)	–	–	–	–	–
Other receivables	–	8,921	–	–	–	–	–	8,921
Deferred tax assets	–	302,121	–	–	–	–	–	302,121
	256,102	1,064,764	(96,524)	–	–	–	–	1,224,342
Current assets								
Inventories	–	3,577	–	–	–	–	–	3,577
Trade and other receivables	29,330	107,196	(38,463)	(7,876)	–	34,130	10,500	134,817
Loan receivable	–	12,759	–	–	–	–	–	12,759
Cash and cash equivalents	2,604	13,354	(12,565)	–	39,000	(20,000)	(10,129)	12,264
	31,934	136,886	(51,028)	(7,876)	39,000	14,130	371	163,417
Total assets	288,036	1,201,650	(147,552)	(7,876)	39,000	14,130	371	1,387,759
Current liabilities								
Trade and other payables	21,499	553,085	–	(423,275)	–	–	1,500	152,809
Borrowings	14,374	809,341	(358,418)	(412,585)	–	–	–	52,712
Short term lease liability	295	–	–	–	–	–	–	295
Deferred revenue	–	4,956	–	–	–	–	–	4,956
Current tax liabilities	–	–	–	–	–	–	–	–
	36,168	1,367,382	(358,418)	(835,860)	–	–	1,500	210,772
Non-current liabilities								
Borrowings	–	18,583	482,418	(18,583)	–	–	14,000	496,418
Deferred tax liabilities	–	–	–	–	–	–	–	–
Provisions	–	68,455	–	–	–	–	–	68,455
Other Payables	–	–	–	–	–	14,130	–	14,130
Employee benefits	–	354	–	–	–	–	–	354
Long term lease liability	5,105	–	–	–	–	–	–	5,105
Deferred revenue	–	144,580	–	–	–	–	–	144,580
	5,105	231,972	482,418	(18,583)	–	14,130	14,000	729,042
Total liabilities	41,273	1,599,354	124,000	(854,443)	–	14,130	15,500	939,814
Net assets/ (liabilities)	246,763	(397,704)	(271,552)	846,567	39,000	–	(15,129)	447,945

Notes

1. The net assets of the Company as at 30 June 2019 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 2019.
2. The net assets of the Target Companies as at 30 June 2019 have been extracted without adjustment from the Historical Unaudited Interim Financial Information on the Target Companies as included in Part 6C of this document.

3. The adjustment in Note 3 reflects the purchase consideration, for the acquisition of Accugas, SUGL and Universal and certain other assets that were acquired from the Seven Group including the re-instatement of US$136.5 million of borrowings. The adjustment also includes the reclassification of US$482.4 million of borrowings as long term borrowings in accordance with the terms of the various facilities (as further detailed in Part 2 and Part 11 of this document). For the purposes of this pro forma information, no adjustment has been made to the separate assets and liabilities of the Target Companies, including the deferred tax asset, or to the purchase consideration paid, to reflect their fair values at the time of the Transaction. The difference between the value of the net assets of the Target Companies as stated at their book value at 30 June 2019 and the estimated consideration is presented below. The net assets of the Target Companies and the fair value of the purchase consideration will be subject to a fair value restatement as at the effective date of the Transaction as required by IFRS 3 (Revised). The actual value of intangible assets included in the Group's next published financial statements may therefore be materially different from that included in this pro forma statement of net assets.

Assets acquired	*US$000*
Net liabilities of the Nigeria Assets	(397,704)
Elimination of amounts due to related parties	846,567
Other assets acquired	292
Book value of net assets acquired	449,155
Consideration	
Cash and cash equivalents (including estimated transaction costs)	12,565
Repayment of borrowings	96,816
Re-instatement of borrowings	136,500
Other loans and payables	38,463
Consideration for the Transaction	284,344
Difference between the value of the assets acquired and the consideration paid	164,811

The bargain purchase shown by the above calculation would be credited to the income statement.

4. The adjustments in Note 4 reflect the elimination, under the terms of the Capital Restructuring, of amounts owed by the Target Companies as at 30 June 2019 to other members of the Seven Group that are not being acquired under the terms of the Transaction:

	US$000
Amounts owed by related parties	7,876
Amounts due to related parties	
Trade and other payables	(423,275)
Borrowings	(431,168)
	(854,443)

The bargain purchase shown by the above calculation would be credited to the income statement.

5. The adjustment in Note 5 reflects the impact of the AIIM Transaction after taking into account the US$15 million contribution by AIIM to the Company's transaction costs.

6. The adjustment in Note 6 reflects the impact of the FOL Transaction as set out in Part 2 and Part 11 of this document. No account has been taken of further payments amounting to approximately US$1.4 million that have been made pursuant to the FOL Transaction subsequent to completion of that transaction.

7. Other adjustments comprise the following:

	US$000
(a) Trade and other receivables	
Amounts due from Seven Energy following the increase in loan notes made by the Group	10,500
(b) Cash and cash equivalents	
Increase in loan notes to Seven Energy	(10,500)
Proceeds from the issue of the Accugas HoldCo Senior Secured Notes	20,000
Estimated transaction costs	(19,629)
	(10,129)
(c) Trade and other payables	
Accrued transaction costs	1,500
(d) Borrowings	
Debt element of the Accugas HoldCo Senior Secured Notes	14,000

The increase in loan notes to Seven Energy was to fund Seven Energy's costs relating to the Transaction.

Estimated transaction costs represent costs incurred in connection with the Acquisition, Capital Restructuring and Re-Admission, after deducting the US$15 million contribution by AIIM to the Company's transaction costs. 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.

No account has been taken of the net present value of the cash flows and amortised cost of the principal relating to the debt element of the Accugas HoldCo Senior Secured Notes.

8. No account has been taken of the trading results of the Company or of the Target Companies since 30 June 2019 or of any other changes in their respective financial positions since this date.

PART 8

COMPETENT PERSON'S REPORT FOR THE NIGERIAN ASSETS

CGG Services (UK) Limited

COMPETENT PERSONS REPORT

Uquo and Stubb Creek Fields, Nigeria

FOR:-

Savannah Energy PLC

Strand Hanson Limited

CGG Project No: BP524

CGG Services (UK) Limited
Crompton Way, Manor Royal Estate
Crawley, West Sussex RH10 9QN, UK
Tel: +44 012 9368 3000, Fax: +44 012 9368 3010

cgg.com

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 five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

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 Energy PLC (Savannah) 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 independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where it was judged appropriate. 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.

In undertaking this valuation CGG have used data supplied by Savannah and Seven Energy in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warrant as to Savannah Energy 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 reserves; (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 Energy PLC.

CGG affirms that from 1st November 2019 (the effective date of the evaluation) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications 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 Energy PLC.

In order to conform to the AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange, CGG has compiled this CPR to conform with Petroleum Resources Management System (PRMS) (2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of petroleum Geologists (AAPG), The World petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). Further details of PRMS are included in **Appendix B** of the CPR.

Conditions of Usage

This report was compiled using existing data during the period 1st September 2019 to 1st November 2019. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant 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 Energy 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 Energy 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.

The copyright of this CPR document remains the property of CGG. It has been provided to Savannah Energy PLC and Strand Hanson Limited 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's website in accordance with the AIM Rules and specifically to the AIM Note for Mining, Oil & Gas Companies (these together being the "Purpose"). CGG agrees to disclose the enclosed CPR to Savannah Energy PLC and Strand Hanson Limited for the Purpose. The recipient should also note that this document is being 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 CGG. Notwithstanding these general conditions, CGG additionally agrees to the publication of the CPR document, in full, on the Savannah Energy PLC's website in accordance with the AIM rules.

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: BP524				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
06	30 April 2020	PW/TU	AJW	Final

Date	**Originator**	**Checked & Approved**
Signed:		

Prepared for:	Prepared By:
Savannah Energy PLC 40 Bank Street London E14 5NR Strand Hanson Limited 26 Mount Row London W1K 3SQ	Andrew Webb CGG Services (UK) Limited Crompton Way, Manor Royal Estate Crawley, West Sussex RH10 9QN United Kingdom

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1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah) and Strand Hanson Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) on the petroleum interests held by Savannah Energy PLC (Savannah) in Nigeria, namely, the Uquo and Stubb Creek Marginal Fields and the Accugas Midstream Business. Those interests were acquired in November 2019 from Seven Energy International Limited (Seven) and Savannah's net asset interests assume completion of the Seven acquisition and the associated restructure of ownership with Frontier Oil at the Uquo Field.

The effective date for the evaluation is 1st November 2019.

1.1 Licence Interests

Savannah holds an 80% interest in the exploration, development and production of gas within the Uquo Field through its 80% owned subsidiary Seven Uquo Gas Limited (SUGL). The remaining 20% interest in SUGL is held by African Infrastructure Investment Managers (AIIM), a leading African-focused private equity firm. SUGL holds responsibility for all operations of the gas project at the Uquo Field, including control of gas-related capital investment projects and day to day gas operations.

Savannah also holds a direct 51% operated interest in the Stubb Creek Field through its 100% economic ownership of Universal Energy Resources Limited (Universal).

In addition, Savannah holds an 80% interest in the Accugas Midstream Business, which owns and operates the 200 MMscfd Uquo gas Central Processing Facility (CPF) and c. 260km pipeline network, as well as holding Gas Sales Agreements (GSA) with downstream customers. The remaining 20% of Accugas is held by AIIM.

Asset	Operator	Savannah Interest (%)	Status	Licence expiry date	Licence Area
Uquo Gas*	SUGL	80%	Production	2035	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

* Interest in the Gas and Condensate only, following the restructure of ownership interests at the Uquo Field with Frontier

Table 1-1 Current Licence Details

For the Uquo Marginal Field, the licence was renewed by the Department of Petroleum Resources (DPR) for a period of 20 years on 18th June 2015. For the Stubb Creek Marginal Field, the licence was renewed by the DPR for a period of 10 years from 1st May 2016.

CGG have assumed, based on its experience and pursuant to the relevant Marginal Field Guidelines, that the DPR is likely to extend the licences beyond the above tabulated expiry dates, if there are still Reserves to be produced. These extensions would be awarded in several phases until the fields reached the end of their economic lives. The Reserves stated in this CPR therefore assume production to the end of the economic lives of the fields.

1.2 Asset Details

1.2.1 Uquo Field

The Uquo Field is producing gas from 4 wells and has been on production since Q1 2014. Production is sold under a Gas Sale Agreement to Accugas, a Midstream company in which Savannah has an 80% interest. Accugas then processes, distributes and markets the gas to two power plants and a cement factory under long-term take or pay contracts. A summary of the contracts is presented **Table 1-2**. In order to maintain the contracted production rates, Savannah plans to bring on stream 5 additional wells over the next 5 years while Accugas will install compression facilities.

1.2.2 Stubb Creek Field

The Stubb Creek Field is producing oil from 3 wells and has been on production since Q1 2015. Production is transported via pipeline to the Exxon-Mobil operated Qua Iboe Terminal. Universal plans to debottleneck the production facility in order to increase capacity from about 3,000 bopd to 5,000 bopd. A water disposal well is also planned. The Contingent Gas Resources will be developed and sold to Accugas, once the Uquo Field Reserves and Contingent Resources is not sufficient to meet the Daily Contracted Quantity (DCQ).

1.2.3 Accugas

The Accugas facilities consist of a two train 200 MMscfd Central Processing Facility (CPF) located near to the Uquo Field, and approximately 260 km of pipelines connecting the CPF to the current three Downstream gas purchasers. Total Daily Contracted Quantity (DCQ) under the three Gas Sales Agreements (GSA) in place is 189.4 MMscfd, and the GSAs have Take or Pay (ToP) provisions within them (set at 80% of DCQ).

Contract term	Calabar Power Plant	Unicem Cement Plant	Ibom Power Plant
Length of contract	20 years	20 years	10 years
Contract end	Sept 2037	Dec 2031	Dec 2023
DCQ	131.0 MMscfd	38.7 MMscfd	19.7 MMscfd
Take or Pay (ToP)	80% of DCQ	80% of DCQ	80% of DCQ
Gas price	2019 \$3.53/Mscf increasing in steps to \$5.04/Mscf in 2024 All indexed to US PPI	\$5.0/Mscf (all years)	2019 \$2.18/Mscf Thereafter escalated with US CPI

Table 1-2 Details of Accugas Gas Sales Agreements

1.3 Reserves and Resources

A summary of the Reserves and Resources associated with the Uquo and Stubb Creek Fields, both gross and net attributable to Savannah, in accordance with the 2018 Petroleum Resource Management System (PRMS), are shown in the tables below. Net attributable Reserves have been derived from the Savannah's economic model. Net attributable Contingent and Prospective Resources have been estimated by multiplying gross Resources by the respective ratio derived from the economic model.

	Gross on Licence			Net attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil (MMstb)							
Stubb Creek	7.9	15.4	25.0	1.7	3.7	6.4	Universal
Gas (Bscf)							
Uquo	301.0	500.9	721.7	240.8	400.7	577.4	SUGL
Condensate (MMstb)							
Uquo	0.4	0.7	1.0	0.3	0.5	0.8	SUGL

Notes
1. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied.*
2. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *Reserves are stated after the application of an economic cut-off*
4. *Full definitions of the Reserves categories can be found in Appendix B*

Table 1-3 Reserves as at 1st November 2019

	Gross on Licence			Net attributable				Operator
	1C	2C	3C	1C	2C	3C	Risk Factor	
Oil (MMstb)								
Stubb Creek	-	-	-	-	-	-		Universal
Gas (Bscf)								
Uquo	45.0	72.5	115.6	36.0	58.0	92.5	>75%	SUGL
Stubb Creek	364.9	515.3	680.3	208.0	293.7	387.8	>75%	Universal

Notes
1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
5. *Full definitions of the Contingent Resource categories can be found in Appendix B*
6. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 57% of gross volumes*

Table 1-4 Contingent Resources

	Gross on Licence			Net attributable				Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate	Risk Factor	
Gas (Bscf)								
Uquo	362.7	578.8	921.6	290.2	463.0	737.3	25-75%	SUGL
Stubb Creek	9.0	13.9	20.9	5.1	7.9	11.9	25-75%	Universal

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 a probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *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*
5. *Risk factors: low = > 75%, medium = 25% - 75%, high = <25%*
6. *Full definitions of the Prospective Resource categories can be found in Appendix B*
7. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 57% of gross volumes*

Table 1-5 Prospective Resources

1.4 Economic evaluation

The Net Present Values (NPV) of future cash flows derived from the exploitation of the Reserves as at 1st November 2019 are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes and are based on the October 2019 Brent forward strip, as set out in **Table 6.2**, and the Gas Sales Agreement. Costs are also assumed to escalate at 2% per year from the end of 2020.

NPV10 ($USMM) of Reserves Net to Savannah			
	Proved	**Proved & Probable**	**Proved, Probable & Possible**
Uquo (gas and condensate)	139.2	227.7	322.1
Stubb Creek oil	38.1	56.7	72.0
Total	**177.2**	**284.4**	**394.1**

Table 1-6 NPV10 ($USMM) of Reserves Net to Savannah as at 1st November 2019

Sensitivities have been calculated for total NPV for variations in oil price, Capex and Opex. The results of this analysis are tabulated below.

NPV10 ($USMM) Net to Savannah			
	Uquo	**Stubb Creek**	**Total**
Base case (Proved+Probable)	227.7	56.7	**284.4**
Oil price -25%	223.2	46.7	**269.9**
Oil Price +25%	232.2	65.8	**298.0**
Capex +25%	216.7	56.0	**272.7**
Capex -15%	234.3	57.2	**291.5**
Opex +25%	214.3	55.2	**269.5**
Opex -15%	235.9	57.7	**293.7**

Table 1-7 Proved and Probable NPV10 ($USMM) Sensitivities as at 1st November 2019

The Net Present Values (NPV) of the future cash flows accruing to the Accugas Midstream Business have been extracted from Savannah's integrated economic model and are tabulated below for the base case (ToP). The model has been subject to a high level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for the Accugas Midstream Business (100%) and for Savannah's net 80% interest after deduction of Royalties and Taxes.

It should be noted that there are no gas Reserves or Resources associated with Accugas.

Case	Accugas (100%)	Net to Savannah
Base Case (ToP)	840.9	672.8

Table 1-8 Accugas NPV10s ($USMM)

A summary of the expected net free cashflows accruing to Savannah from the Uquo Field, Stubb Creek Field and Accugas Business is presented in the table below for the base case (ToP).

Year	Cashflow (US$MM)
2020	104.2
2021	128.1
2022	141.3
2023	141.3
Average	*128.7*

Table 1-9 Net Asset Free Cashflows (2020-2023) for the base case (ToP)

2 INTRODUCTION

2.1 Overview

This independent Competent Person's Report (CPR) was prepared by CGG at the request of Savannah Energy PLC (Savannah) and Strand Hanson Limited. The report evaluates Reserves and Resources associated with the onshore Uquo and Stubb Creek Marginal Fields in which Savannah hold interests. These fields are located near the coast in south-east Nigeria.

Frontier Oil Limited (Frontier) and Universal Energy Resources Limited (Universal), both indigenous Nigerian E&P companies, are Operators of the Uquo and Stubb Creek fields respectively.

Seven Uquo Gas Limited (SUGL) has a 100% Operating interest in the Uquo gas project (including associated condensate production). Savannah owns an 80% interest in SUGL, the remaining 20% is held by AIIM. Frontier has a 100% interest in the Uquo oil project.

Savannah has a 51% participating interest in the Stubb Creek field. The latter interest is held via a 100% interest in Universal, which in turn holds a 51% interest in the field. The remaining 49% interest in the field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited (SIPEC).

Savannah also owns an 80% operated interest in Accugas Limited (Accugas), the owner of the Uquo Gas Processing Facility and associated pipeline network. The remaining 20% is held by AIIM. Accugas purchases Uquo gas production, which it then sells to two local power plants and a cement factory. A summary of Savannah's licence interests are tabulated below (**Table 2-1**).

Asset	Operator	Savannah Interest (%)	Status	Licence expiry date	Licence Area
Uquo Gas	SUGL	80%	Production	2035	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

Table 2-1 Current Licence Details

The locations of the Uquo and Stubb Creek Fields, and the Accugas surface facilities are shown in **Figure 2.1**.

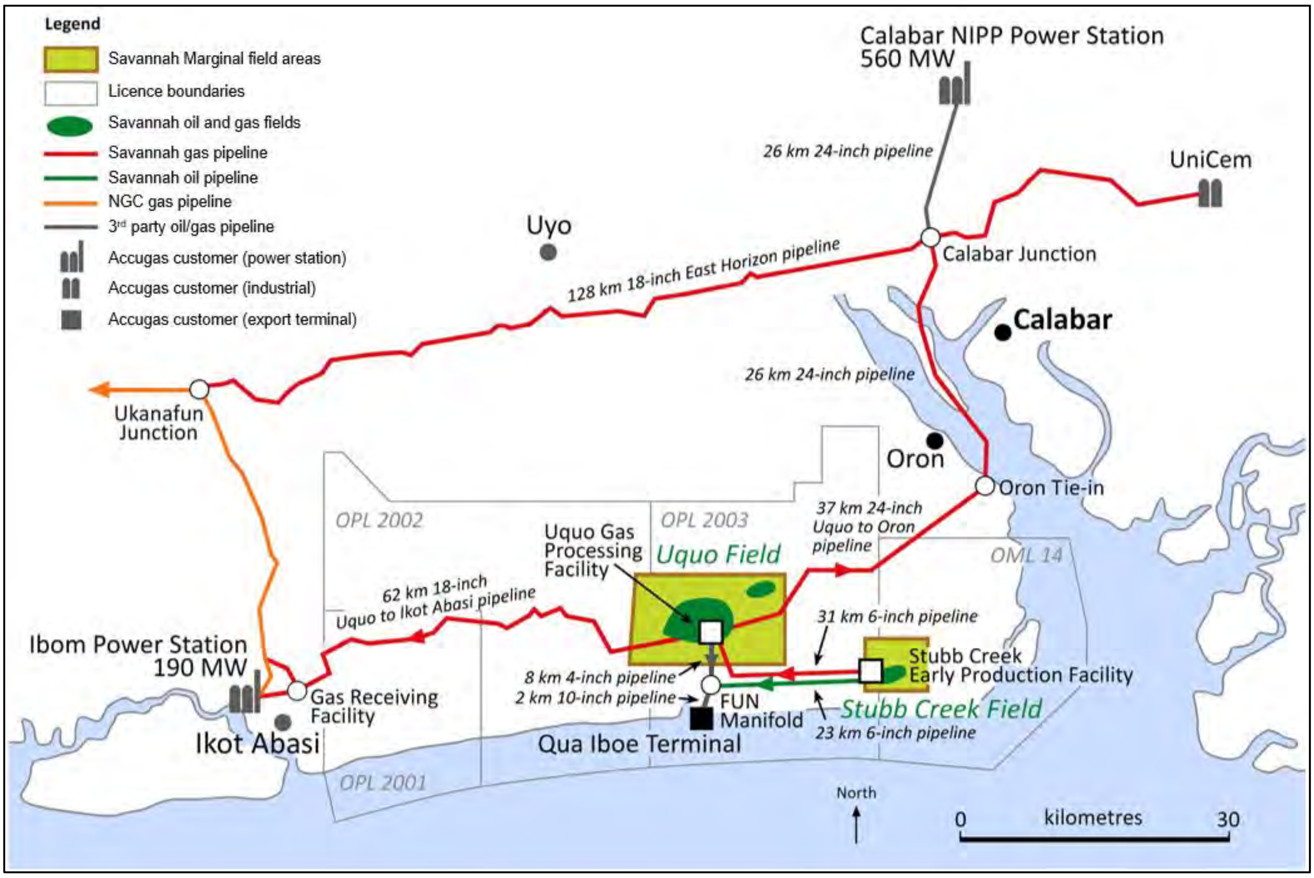


Figure 2-1 Location of Fields and Infrastructure (Source: Savannah, 2019)

2.2 Sources of Information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah and Seven's technical teams as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR has included:

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations
- Historical production and pressure data
- Gas sales contracts and farmout agreements
- Work plans and budgets

In conducting the evaluation, CGG have accepted the accuracy and completeness of information supplied by Savannah and Seven Energy, and have not performed any new interpretations, simulations or studies.

No site visit to the facilities has been conducted by CGG as it was not part of the work scope in the letter of engagement.

2.3 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

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.

Dr. Arthur Satterley

Arthur Satterley has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 20 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces.

James Buckley

James Buckley has a BSc (Hons) in Applied Geology and Resource Management from the University of Birmingham and an MSc in Petroleum Geoscience from Royal Holloway, University of London. James has worked at CGG since graduating in 2011, predominantly working in prospect generation and reserves estimation and volumetrics. This has culminated in James participating in several North Sea Licensing Rounds. James also has experience in the geology of many other basins around the world, including the pre-salt Santos Basin on which he published a Geological Society paper in 2015. Additionally, James has been a reviewer for the 'Palaeogeography, Palaeoclimatology, Palaeoecology' Journal. James is a member of the PESGB.

Dr Christopher O. Iwobi

Chris Iwobi gained his BSc. and PhD degrees from the University of Calabar, Nigeria. He has over 29 years' experience in exploration geology including 13 years with the Nigerian Agip Oil Company in the Niger Delta. On joining Robertson's in 2005, Chris has been involved in evaluations of assets in various parts of the world including Northern Europe, North Africa, Southeast Asia, West Africa and the Middle East. He has also worked on a variety of basin-scale play fairway evaluations and screening opportunities for unconventional hydrocarbon plays. Chris is a member of the American Association of Petroleum Geologists (AAPG).

Toni Uwaga

Toni Uwaga has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has several technical papers, published by GSTT and SPE.

Peter Wright

Peter Wright 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.

2.4 Evaluation methodology

In evaluating the Reserves and Resources associated with the fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation. More detailed descriptions of the workflow and methodologies employed are provided in the relevant sections of this report.

As an initial stage in the evaluation process, Seven demonstrated the seismic interpretations during a visit by CGG to their London office in October 2018. During the same visit, geological, engineering and commercial issues were also discussed face to face with Seven's technical staff.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Reserves, production profiles and estimates of capital and operating costs provided by Savannah and Seven. The Reserves have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

The evaluation has been performed in accordance with the:-

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)

- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

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 Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

3 GEOLOGY AND GEOPHYSICS

3.1 Regional geology

The Uquo and Stubb Creek Fields are located within the eastern Niger Delta, which is part of the prolific Niger Delta hydrocarbon province in Southern Nigeria. The Niger Delta is one of the world's largest Tertiary delta systems, covering an area of approximately 75,000km^2, which has historically been fed by the Niger, Benue and Cross river systems. The basin is located on the West African continental margin at the site of a triple junction that formed during continental break-up during the Cretaceous. The delta sequence consists of an upward-coarsening regressive sequence of Tertiary clastics up to 12 km thick. The dominant subsurface structures are listric normal faults, which detach close to the top of the underlying marine claystone surface at the top of the Akata Shale. These listric faults provide an array of trapping mechanisms for hydrocarbons in the subsurface, particularly within the associated rollover anticline structures. Major growth faults cross the delta from northwest to southeast, dividing the delta into a series of depobelts that have been prograding south-westwards for approximately 55 Myr (**Figure 3-1**).

The northern boundary fault for each of the depobelts marks the approximate position of the palaeo-coastline during the major progradational stages. Hydrocarbons have been located in all of the depobelts of the Niger Delta, typically in good quality sandstone reservoirs within the main deltaic sequence.

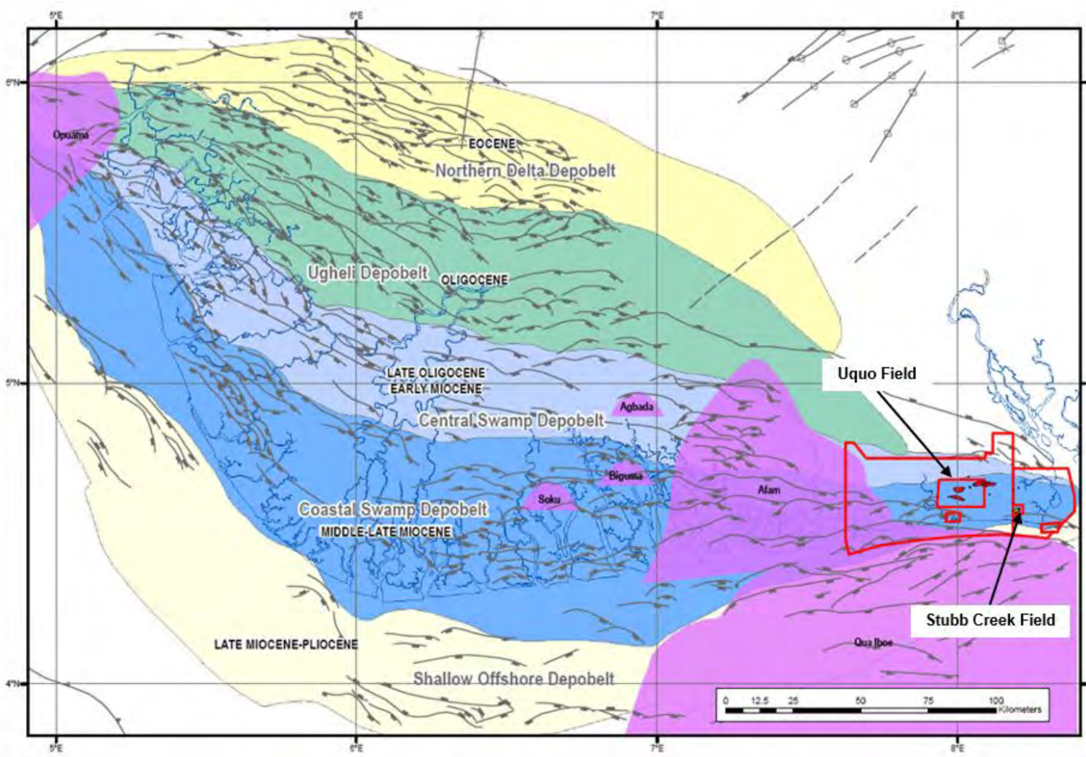


Figure 3-1 Depobelts of the Niger Delta (Source: CGG)

The stratigraphic sequence in the Niger Delta is broadly subdivided into the marine Akata Formation, paralic Agbada Formation and continental Benin Formation (**Figure 3-2**).

Hydrocarbons in the Uquo and Stubb Creek Fields have been generated from the prodelta mudstones of Akata Formation and the interbedded paralic mudstones of the Agbada Formation. Upon maturation, hydrocarbons migrated either updip through carrier beds, or vertically along fault planes into the deltaic sandstones of the Early Miocene Agbada Formation. At Uquo and Stubb Creek, the Agbada Formation is represented by the hydrocarbon-bearing "C" and "D" sands. The seal to these sands is provided by interbedded deltaic mudstones, which are thick and competent across the basin.

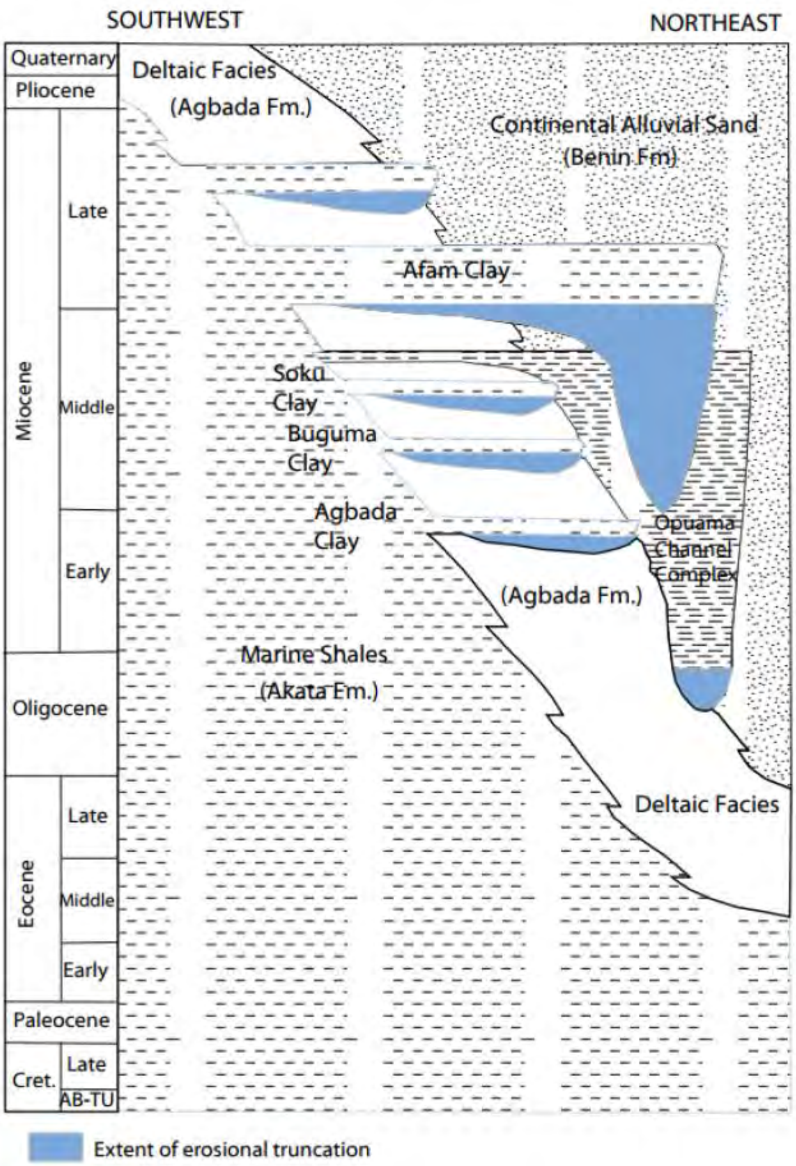


Figure 3-2 Lithostratigraphic column showing the key Tertiary sedimentary sequences in the Niger Delta (Source: Tuttle et al., U.S. Geological Survey, 1999)

3.2 Uquo Field

3.2.1 Uquo Field Summary

The Uquo Marginal Field Licence is located within OML 13, onshore Nigeria. Gas has been discovered in 12 different 'C' and 'D' sand reservoirs in the Agbada Formation.

The Uquo Field is made up of 3 main areas; Uquo-2 (Uquo-2 & 4 wells), Uquo-3 (Uquo-3, 7 & 8/8ST wells) and Uquo NE (Uquo 9/9ST well), with small volumes also present in Uquo-5 area (Uquo-1, 5 & 5ST/6 wells). The upper 'D' reservoirs contribute the greatest volumes of hydrocarbons in the Uquo area (**Figure 3-3** and **Figure 3-4).**

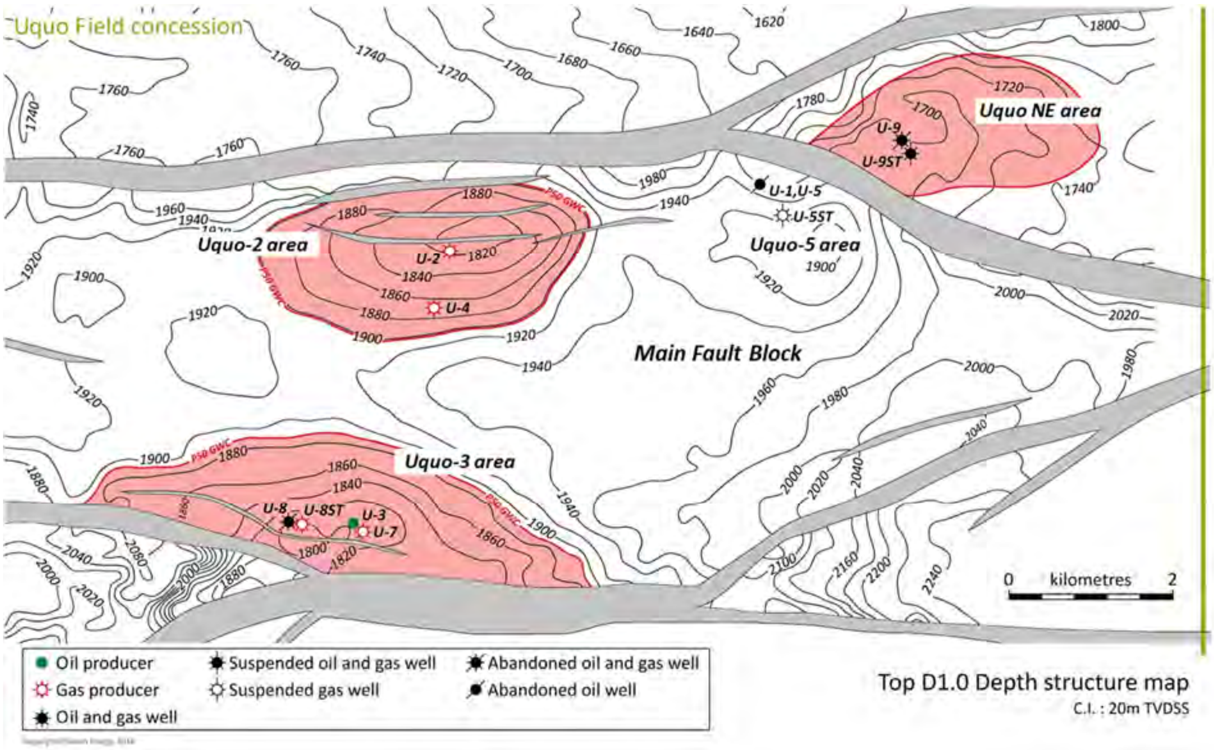


Figure 3-3 Uquo Field structure map (Source: Seven, 2017)

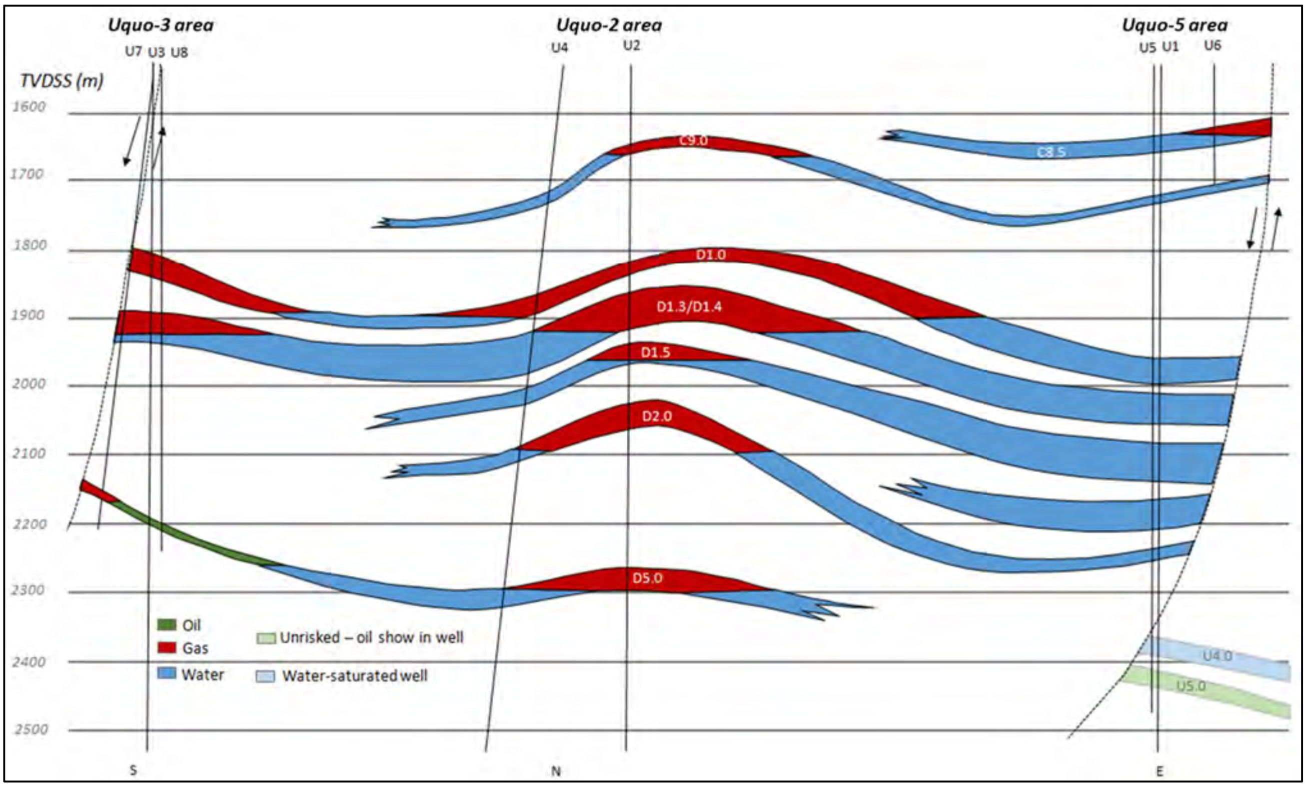


Figure 3-4 Schematic diagram showing the reservoir intervals of the Uquo Field (Source: Seven, 2017)

The Uquo Field was first drilled in 1958 by Shell Petroleum Development Company Nigeria (SPDC); the composite logs from Uquo-1 supplied by Seven suggest that this well only encountered thin gas intervals, although it was reported to have discovered oil and gas in four sands. The subsequent Uquo-2 well was drilled as an exploration well and encountered significant volumes of gas in all of the sands between C9.0 and D5.0 (7 different reservoir intervals). Another exploration well and one appraisal well were drilled in 1971/72; Uquo-3 encountered gas in the D1.0 & D1.3/D1.4 sands, and oil in the D5.0 sand, whereas Uquo-4 encountered gas throughout the D1.0 sand and in the upper part of the D2.0 sand.

Drilling activity restarted in 2008, targeting oil discovered by Uquo-1; the Uquo-5 well failed to confirm the presence of the Uquo-1 oil accumulation. The well was subsequently sidetracked (Uquo-5ST), but was terminated before reaching the target depth due to mechanical problems. However, Uquo-5ST confirmed gas in one reservoir (C8.5). In January 2010, Uquo-3 was worked-over and completed as an oil producer in the D5.0 reservoir, Uquo-2 and -4 were subsequently completed as gas producers in the D2.0 and D1.0 reservoirs, respectively. The gas accumulations were further appraised by Uquo-7, -8 and -8ST between June and September 2013. Uquo-7 and -8ST were completed in 2014 as gas producers in the D1.0 reservoir. Exploration drilling returned to the Uquo area in November 2014, resulting in the Uquo NE discovery with the Uquo-9/9ST well suspended as an oil and gas discovery. The Uquo-9/9ST well will be completed and operated as an oil producer by Frontier.

3.2.2 Uquo Field Subsurface Overview

CGG have carried out an independent analysis of the Uquo Marginal Field Licence using the 195 km^2 3D seismic volume supplied by Seven. The survey was acquired during 2006 and 2007. Around 24.5 km^2 of the licence is not covered by seismic, due to the presence of the Eket Airfield to the west of the licence. In addition, there are areas within the dataset that suffer from poor fold coverage due to the presence of villages.

The data was provided to CGG as a Kingdom™ Project; wells, horizons, faults and depth surfaces provided by Seven have been QC'd and used as a basis for generating volumetric estimates. Composite logs were supplied which contain formation depths as well as fluid contacts, which have been used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The quality of the seismic data is generally good at the key reservoir levels, although the aforementioned acquisition impediments do result in a decrease in data quality in a few areas. The footwalls of most of the faults are generally poorly imaged, particularly in the deeper section, which makes the delineations of some of the gas-bearing reservoirs more uncertain. In addition, the seismic volume is a Pre-Stack Time Migration (PSTM); it is CGG's opinion that the accuracy of the tabulated volumetrics would be improved if the volume were to be re-processed to PSDM (Pre-Stack Depth Migration) which Savannah is planning to conduct in 2020.

In addition to the Kingdom™ project, Seven has provided reports to assist with CGG's G&G analysis; these include Petrophysics, Geoscience and Reservoir Engineering studies.

The Uquo Marginal Licence contains a number of different structural features due to a series of extensional faults that generally trend in an E-W direction. There are three structural culminations in the main fault block, two in the north (Uquo-2 and 5 areas) which are dip-bounded, and one dip and fault-closed structures in the south (Uquo-3 area). At the D1.0 level, Uquo 2 and Uquo 3 areas are in communication (pressure connection proven by production data) as seen in **Figure 3.5**. In the Uquo-2 area, the reservoirs are intersected by some small-offset extensional faults. CGG's Reservoir Engineering analysis suggests that this has not resulted in any compartmentalisation issues.

The Uquo 3 area has a different structural configuration, in that the reservoirs are trapped in the footwall of a large extensional fault. The rotation of the main fault block has resulted in some structural relief into which hydrocarbons have migrated and remained trapped. The southern edge of the Uquo 3 reservoirs are difficult to pick with accuracy in the deeper section, due to fault shadow effects in the seismic clearly seen in **Figure 3.5**. The majority of the gas reservoirs in the Uquo field are easy to pick; many exhibit a bright amplitude response (as exhibited in **Figure 3.6**) as a result of the presence of gas within a high-quality, porous reservoir. Many also exhibit flat spots, which help to define the contacts in some of the accumulations (if no gas-water contact has been encountered in the wells on-structure).

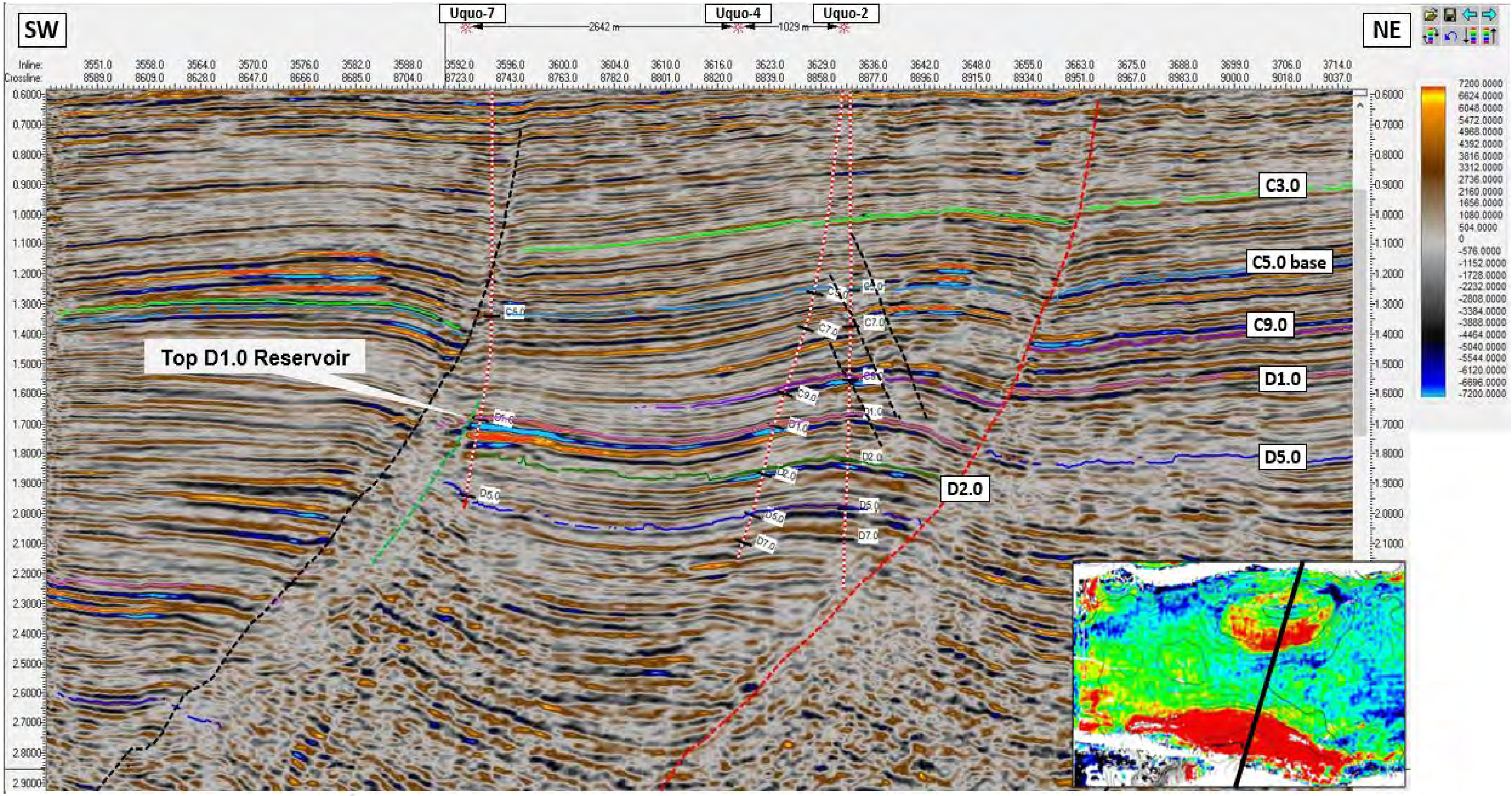


Figure 3-5 N-S line through Uquo-3 and Uquo-2 areas (Source: Seven, 2019)

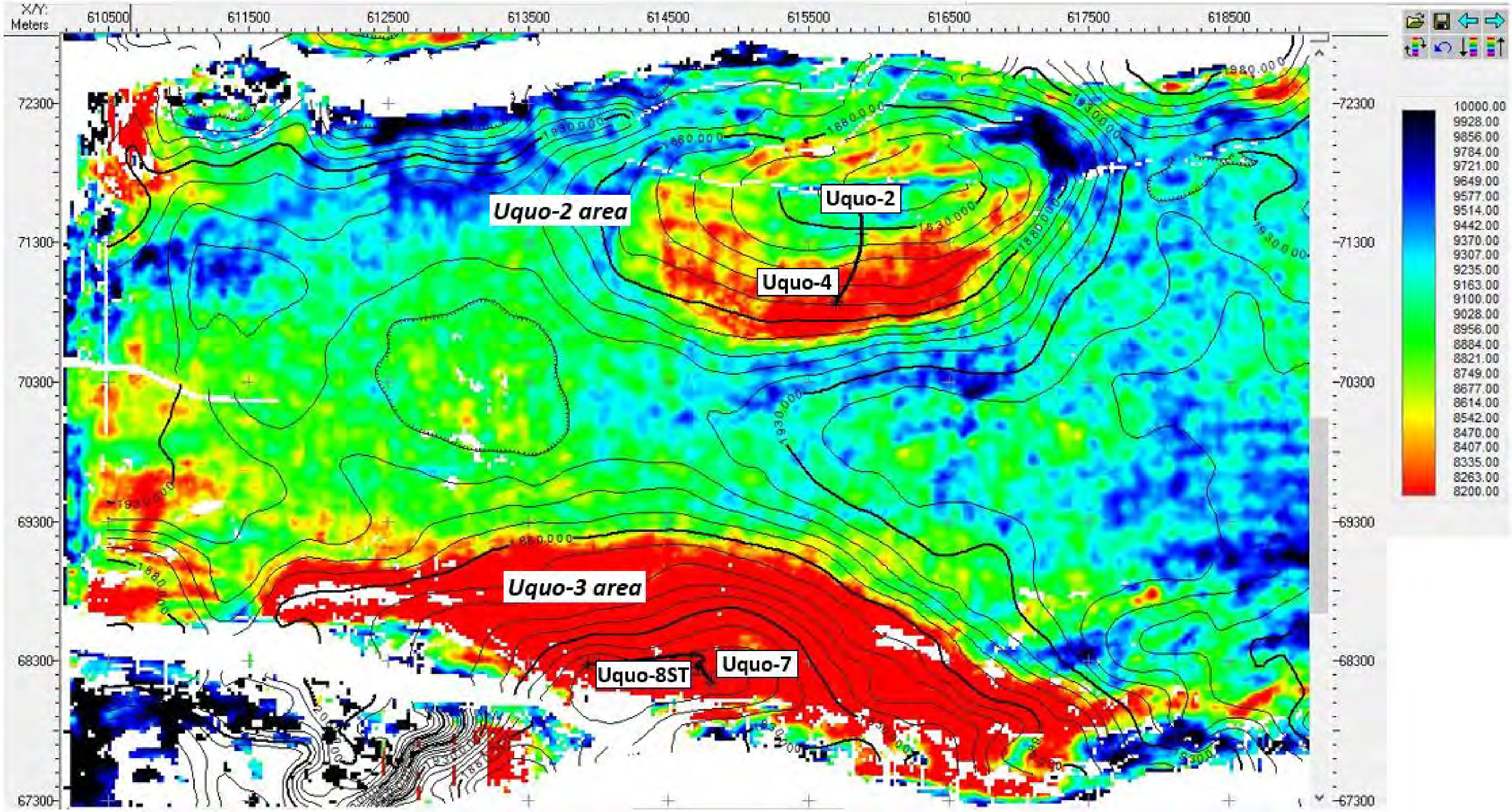


Figure 3-6 Relative Acoustic Impedance at the D1.0 level with depth contours in mSS (Source: Seven, 2017)

The Uquo-9/9ST discovery is located in a separate fault compartment, namely Uquo NE towards the North East of the main fault block. Hydrocarbons were discovered in 9 reservoirs in Uquo-9/9ST well; mainly gas except for the D1.6 and D7.0 reservoirs which encountered oil. The ultimate areal extent of the Uquo NE shallow gas discovery is unknown, as it extends outside the area of 3D seismic coverage, as shown below in **Figure 3-7**. The seismic over Uquo NE is quite poor (shown in **Figure 3-8**) in places due to an overlying village, although this is mitigated by the data provided by the exploration well on the structure (Uquo 9/9ST).

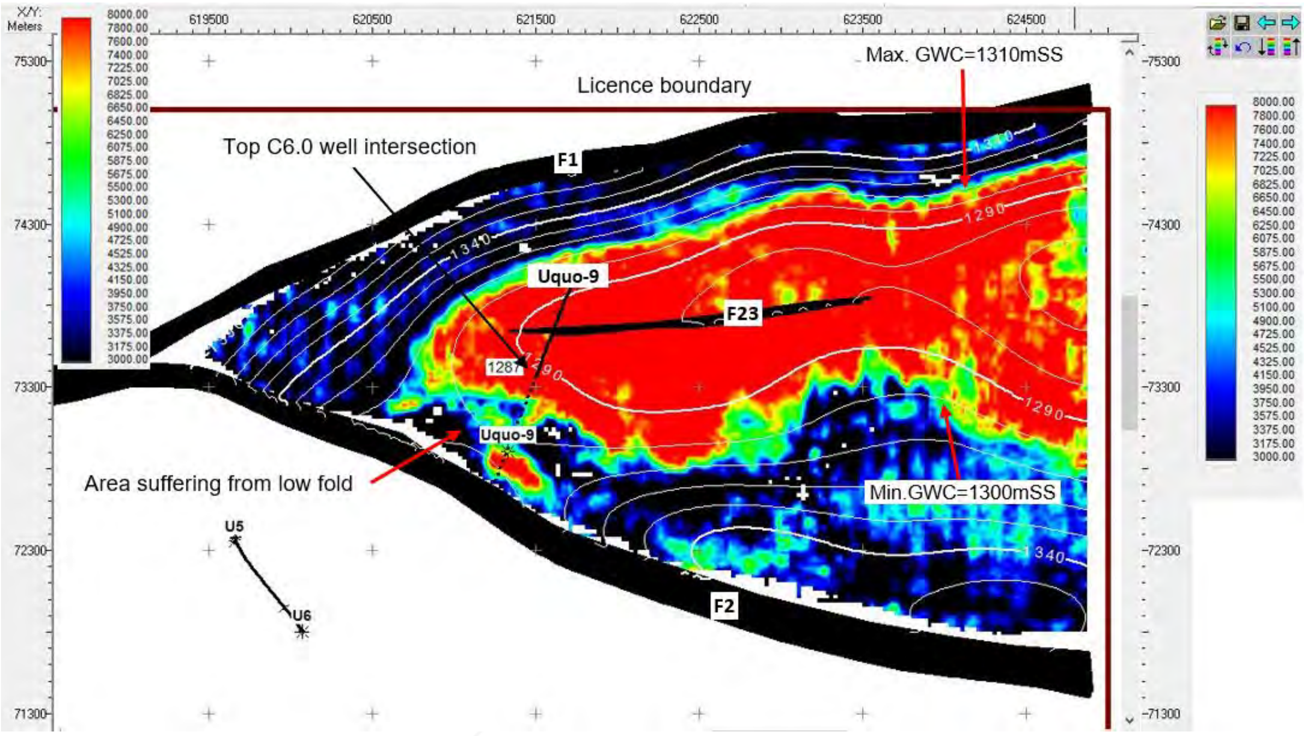


Figure 3-7 Top C6.0 reservoir RMS map (+/-8ms) – Uquo NE area (Source: Seven, 2019)

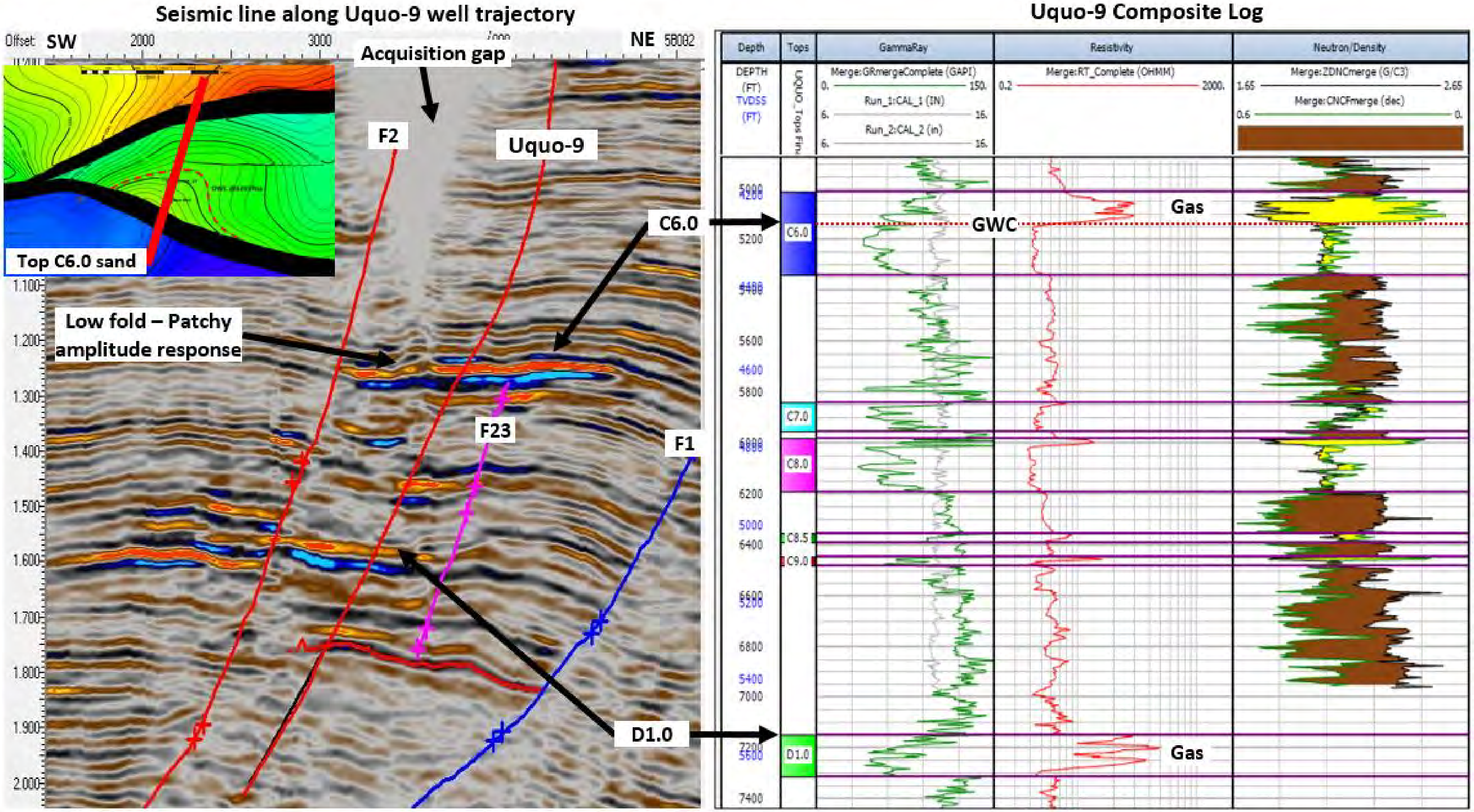


Figure 3-8 N-S seismic line through Uquo NE and Uquo-9 composite log (Source: Seven, 2019)

The Agbada C and D sand reservoirs are of high quality at the Uquo Field; NTG (Net-To-Gross) is generally in excess of 90% and porosity is usually 27% or higher. In addition to the discovered volumes, Seven have identified a series of additional prospects, as seen in **Figure 3-9.**

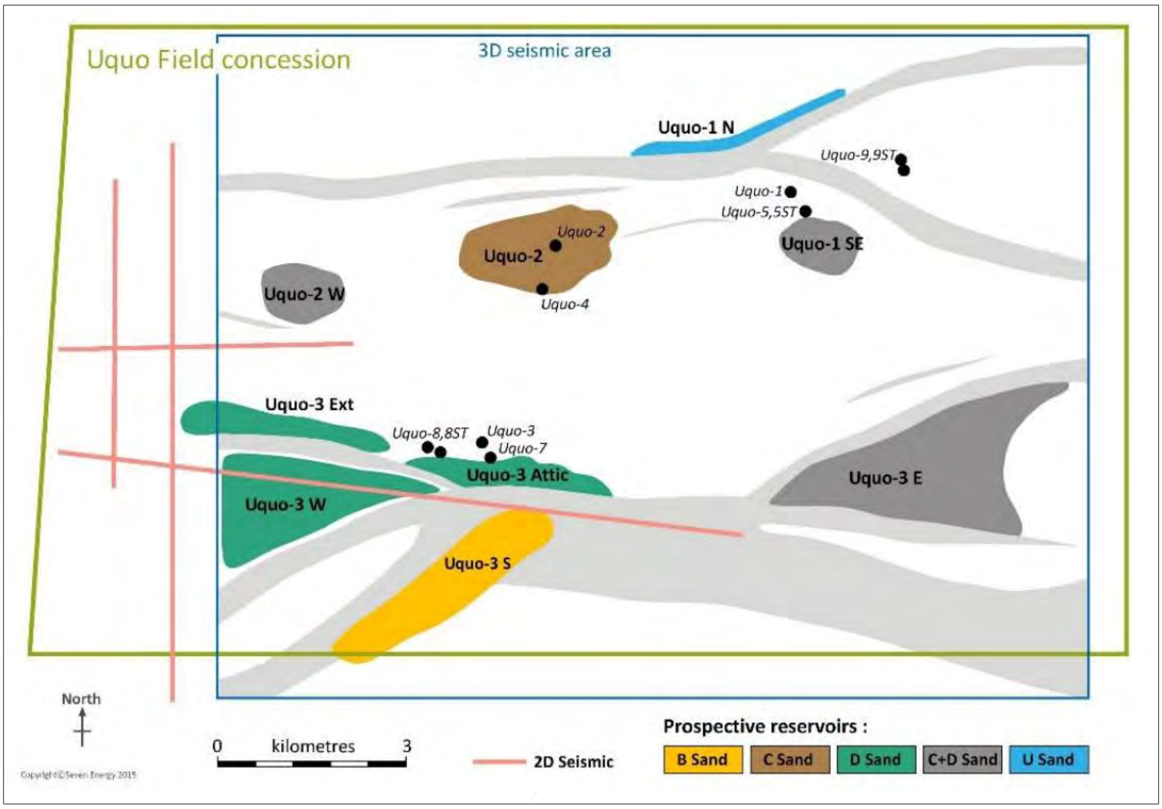


Figure 3-9 Map of prospects in the Uquo Marginal Field Licence area (Source: Seven, 2017)

The subsurface team at CGG has completed a thorough Geological and Geophysical QC of the work supplied by Seven and using the Kingdom™ project provided, have independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by Reservoir Engineering and Petrophysics experts who have also provided inputs for the volumetrics calculations, which were run through a probabilistic Monte Carlo analysis.

3.2.3 Uquo Field Petrophysics

The petrophysical data provided for the C and D sands in the Uquo Field and the nearby Etebi well (Seven, 2017) has been evaluated by CGG in order to obtain P10, P50 and P90 values for the reservoir properties such as the NTG, porosity and hydrocarbon saturations, which were used as inputs for the volumetric calculations. The methodology adopted for petrophysical analysis was found to be reasonable. This comprises the following computations: Volume of clay (Vcl) from GR logs using the Larionov model, porosity from density log and water saturation using the Simandoux saturation model. However, there is no density or sonic log available in Uquo-1 and Uquo-6 so effective porosity was estimated using a Vcl-porosity relationship derived from the nearby Uquo-5 well. Density and sonic logs were available only down to the top of the D sands in the Uquo-8 well, thus porosity calculations are based on the sonic logs for the C sands and a Vcl-porosity relationship was applied to the deeper reservoirs. In the well intervals in which the Vcl relationship was used in determining the porosity (Uquo-1, Uquo-6 and deeper section of Uquo-8), the Sw estimates are based on the Archie equation.

The two sets of cut-offs used in deriving the net reservoir/pay are considered to be reasonable;

- Clean sands: porosity (0.16) and Vcl (0.45)
- Shaly sand: porosity (0.10) and Vcl (0.5)
- A uniform Sw cut-off of 0.50 has been applied throughout

Fluid contacts have also been determined from the petrophysical data and these have been used in combination with the Direct Hydrocarbon Indicators (DHI's) and structural closures in determining the Minimum, Most Likely and Maximum GRV's. **Figure 3-10** presents results from the Uquo-2 well which are representative of the rock properties of the Uquo Field.

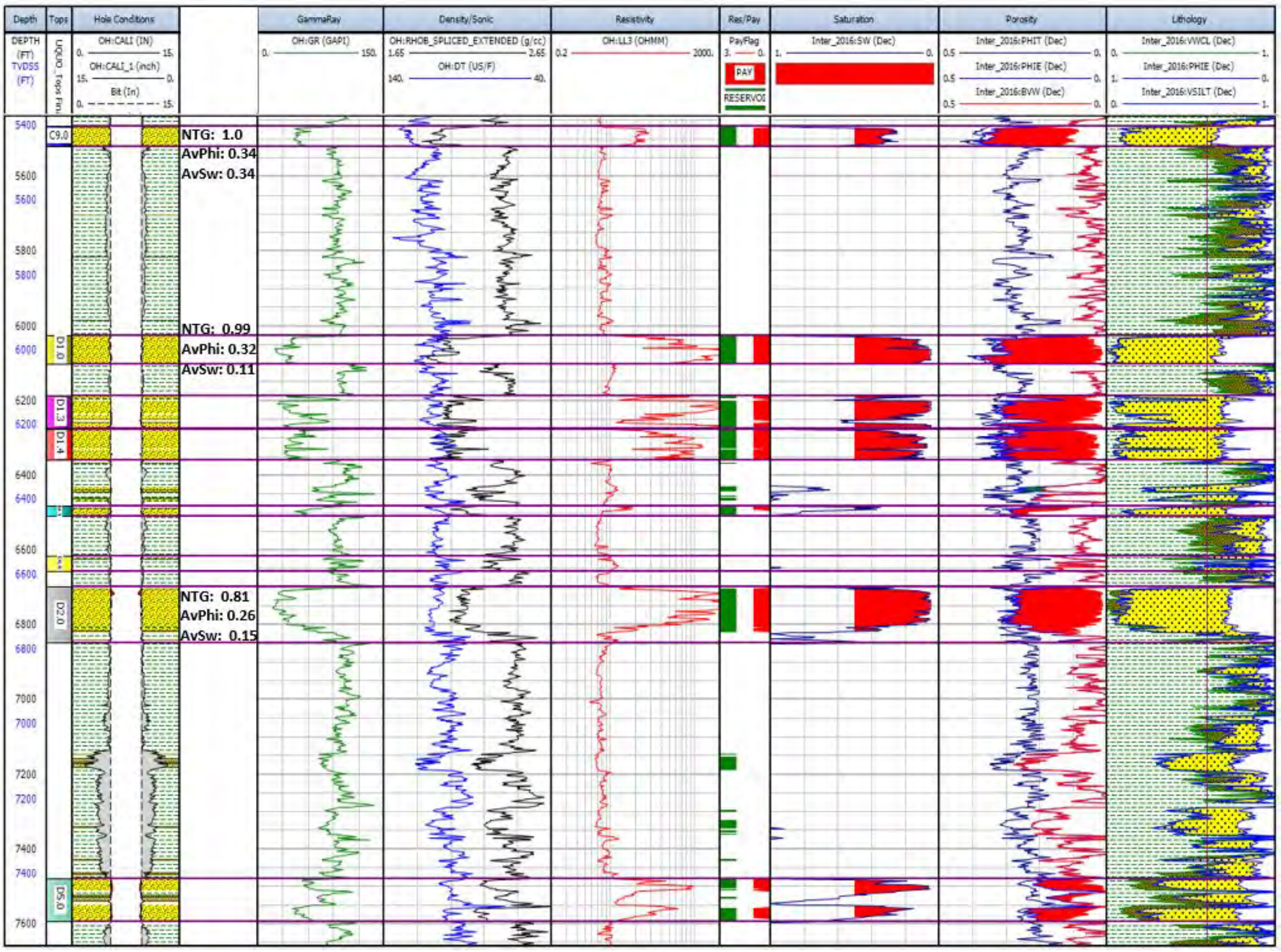


Figure 3-10 Uquo-2 Petrophysical interpretation (Source: Seven, 2019)

3.2.4 Uquo Field In-Place Volumes

The subsurface team at CGG has independently delineated each of the reservoirs/prospects below in Minimum, P50 and Maximum cases using depth surfaces provided by Seven. The horizons interpretations which have been converted to depth surfaces have been extensively QC'd by CGG and were found to be accurate. However, as mentioned in the Subsurface Overview, CGG believe that the accuracy of the volumes would be improved by reprocessing and depth migrating the 3D dataset, and subsequently re-interpreting the Gross Rock Volumes. Formation Volume Factors have also been generated by CGG; rock properties have been derived from Seven's previous work and QC'd by CGG. The inputs have been run as a probabilistic Monte Carlo analysis. A drill stem test (DST) was performed in well Uquo-3 in the gas bearing D1.3/D1.4 reservoirs. The estimated connected gas initially in-place was 21.9 Bscf, which corresponds to the low case in-place volume used.

Tables 3-1 and 3-2 tabulate the current in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Area	Reservoir	Gross GIIP (Bscf)		
		P90	P50	P10
Uquo-2	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	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**	C6.0	80.0	99.8	124.0
Total*		**592.5**	**813.7**	**1056.5**

* Arithmetic sum

** Uquo NE volumes are on-licence only

Table 3-1 Uquo Marginal Field GIIP

Area	Reservoir	Gross GIIP (Bscf)		
		P90	P50	P10
Uquo NE	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	C8.5	11.0	14.3	18.6
Uquo-2	C9.0	17.3	35.9	65.8
Total*		**58.4**	**94.8**	**146.1**

* Arithmetic sum

Table 3-2 Uquo Marginal Field: GIIP excluded from development plan

In addition to the discovered volumes, CGG has reviewed the in-place numbers for the prospects in the Uquo Marginal Field Licence (**Figure 3-9**). **Table 3-3** tabulates Savannah's current in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Prospect	Unrisked Gross GIIP (Bscf)			CoS (%)
	Low	Best	High	
Uquo 1SE	55.7	84.8	139.9	50
Uquo 2	13.6	25.4	51	73
Uquo 2W	71.3	88.4	103.7	57
Uquo 3E	151.5	221.7	335.7	35
Uquo 3S	114.8	154.3	200.1	66
Uquo 3W	72.5	115.2	204.1	18
Uquo 3 Extension	10.2	15.1	22.6	14
Uquo 3 Attic	13.3	23.4	42.6	17
Uquo 3 Fault Zone	49.0	83.8	93.9	20
Uquo 1N	6.1	14.7	35.2	18
Total*	**558.0**	**826.8**	**1228.8**	

* Arithmetic sum

Table 3-3 Uquo Unrisked Prospective Resources GIIP

The Chance of Success (CoS) numbers reflect the fact that the licence is in a prolific hydrocarbon-producing basin, with hydrocarbons proven in many reservoir intervals. The principal risk in the licence area is the trap, which is amplified in areas of poor imaging. Fault seal is also key to the successful trapping of many of the prospects, which at depth is particularly poorly imaged due to fault shadows. Thus, reprocessing the seismic volume over the Uquo licence and improving the data quality would likely improve the CoS of many of the prospects. Savannah is planning to conduct this re-processing in 2020. In addition, some of the traps have an increased risk associated with them as the closures extend beyond the edge of the seismic dataset. Reservoir and source are known to be low risk in the licence area and this has been reflected in Seven's estimated CoS figures. CGG has reviewed Seven's CoS's and deem them to be reasonable estimates.

3.3 Stubb Creek Field

3.3.1 Stubb Creek Field Summary

The Stubb Creek Marginal Field is located within the area OPL 276, formerly OML 14, onshore Nigeria. The Stubb Creek Field was discovered in 1971 by SPDC, who drilled 3 exploration wells and 1 appraisal well (from 1971-1983). The first well, SC-1 well intersected a 42 m gas column within the C3 sand reservoir, while light oil was later discovered in 1971 with the SC-2 well principally within the D3 reservoir (and gas with an oil rim in the C9 reservoir). Overall, oil and gas have been discovered in 7 different 'C' and 'D' sand reservoirs in the Agbada Formation; where hydrocarbons are present, C sand reservoirs are typically gas-bearing apart from C9 reservoir, with the deeper D sand reservoirs containing oil. Outlines of the field are shown in **Figure 3-11** and **Figure 3-12.**

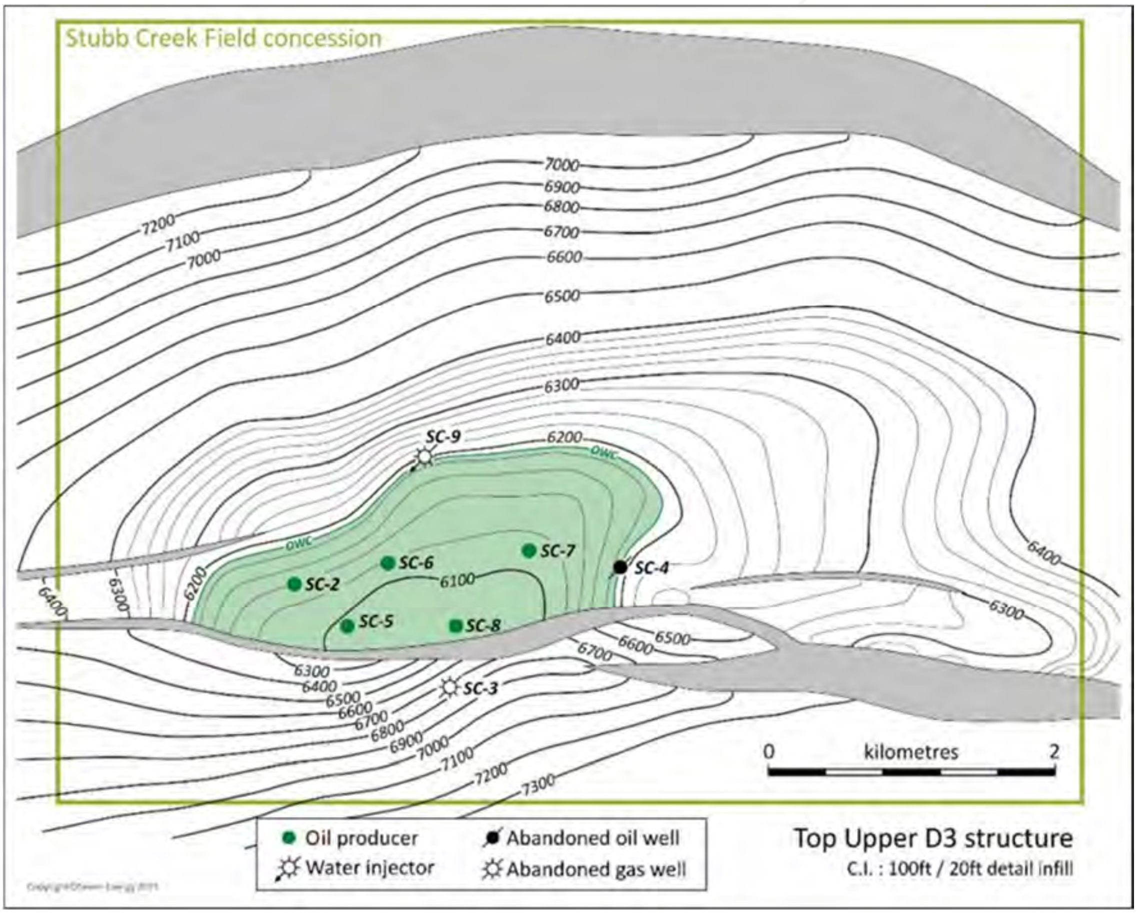


Figure 3-11 Map showing the outline of the Stubb Creek oil field at Upper D3 level (Source: Seven, 2015)

Stubb Creek was classified as a Marginal Field in 2002, with Universal becoming the Operator in 2003. Seven acquired a 62.5% interest in Universal in 2010 and full ownership in 2019, and thereby gained control over the operatorship of the field by virtue of its shareholding and management position. Between 2007 and 2009, Universal drilled 5 oil development wells, with oil production commencing in January 2015.

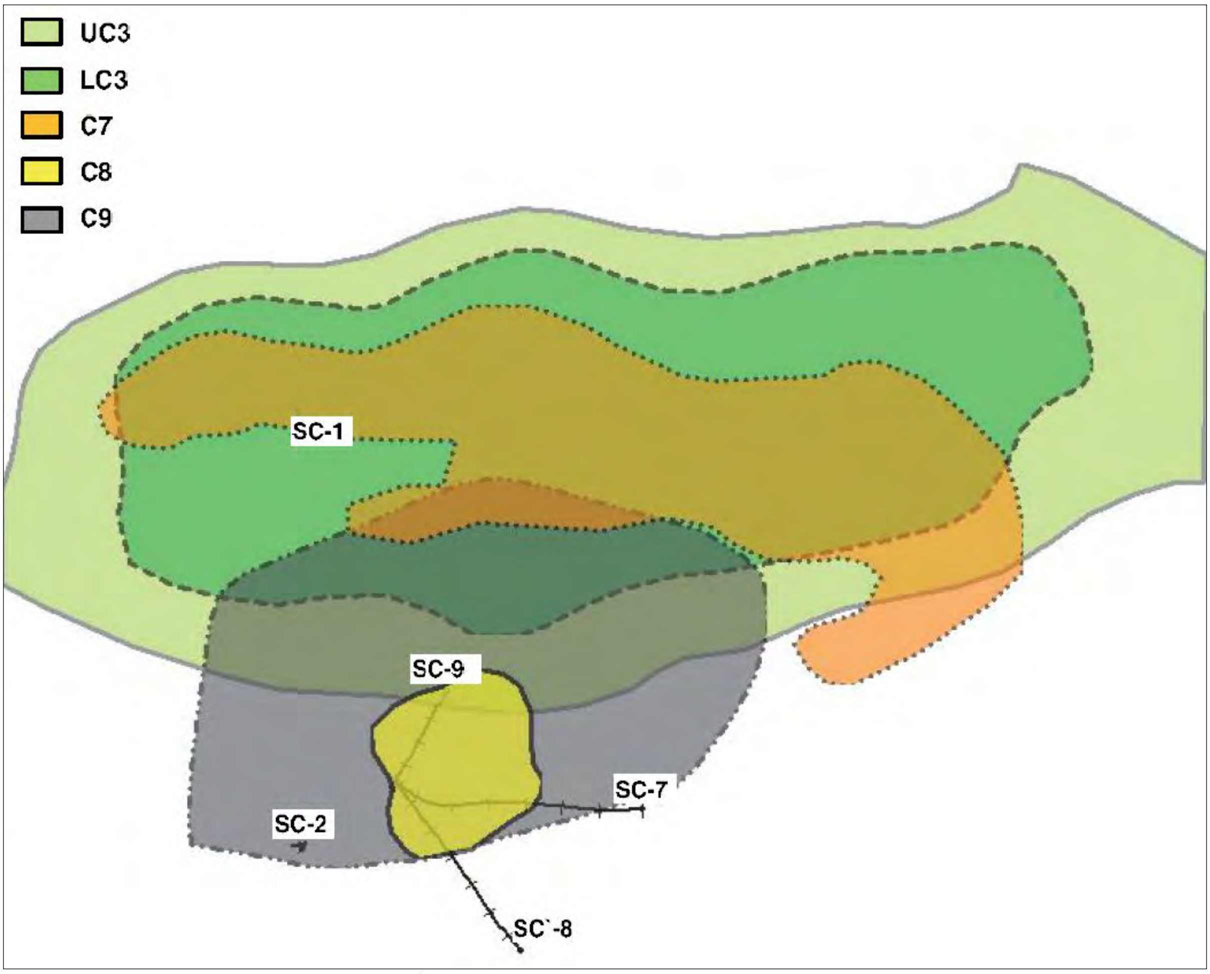


Figure 3-12 Seven Energy outlines of the C Sand gas reservoirs (Source: Seven, 2017)

3.3.2 Stubb Creek Field Subsurface Overview

CGG have carried out an independent analysis of the in-place volumes using a 3D seismic volume acquired in 2005/2006, which covers an area of 65 km^2. The data were supplied as a Kingdom^{TM} project containing wells (with synthetic seismograms), depth grids/horizons and fault interpretations. Composite logs were supplied which contained formation tops as well as fluid contacts which were used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The data quality is generally very good; gas reservoirs are easily distinguished from the background reservoir response - as would be expected in shallow, high quality gas-bearing reservoir sands. The seismic volume is a Pre-Stack Time Migration (PSTM); it is CGG's opinion that the accuracy of the volumetrics shown below would be improved if the volume were to be re-processed to PSDM (Pre-Stack Depth Migration).

In addition to the Kingdom^{TM} project, Seven has provided reports to assist with CGG's G&G analysis; these include Geoscience and Engineering studies for both C & D reservoirs.

The Stubb Creek Field is made up of 7 different hydrocarbon-bearing intervals, all of which are located within a gently-dipping fault block which is downthrown to a major listric fault to the north. The main rollover structure is largely undeformed; however, there is significant E-W trending extensional faulting south of the SC-8 well, creating a series of gravity-driven low angle fault blocks as can be seen in **Figure 3-13**.

The hydrocarbon accumulations occur in a variety of different styles over a relatively small area; the hydrocarbons within the C3 reservoirs are trapped within the crest of the broad rollover anticline, whereas the C7 accumulation appears to be largely stratigraphic in nature. Many of the deeper reservoirs are footwall sands trapped against an extensional fault to the south, with additional structural relief created by the rollover anticline**.**

The C and D sand reservoirs of the Agbada Formation are generally of very high quality; NTG is generally in excess of 90% with porosities of 30% or higher. The C7 reservoir is anomalously poor quality, although the volumes here are relatively insignificant compared to the C3 and C9 GIIP numbers (note that the C3 accumulation appears to extend beyond the limits of the 3D seismic volume and thus may contain some upside volumes not included here). The majority of the reservoirs in the survey are easily picked out on seismic, with flat spots and amplitude anomalies clearly delineating the extent of the gas accumulations (c.f. RMS amplitude map in **Figure 3-14**). In addition to this, Seven provided Relative Acoustic Impedance (**Figure 3-15)** and Average Energy attributes which shows strong agreement with the amplitude data to support Seven’s interpretations.

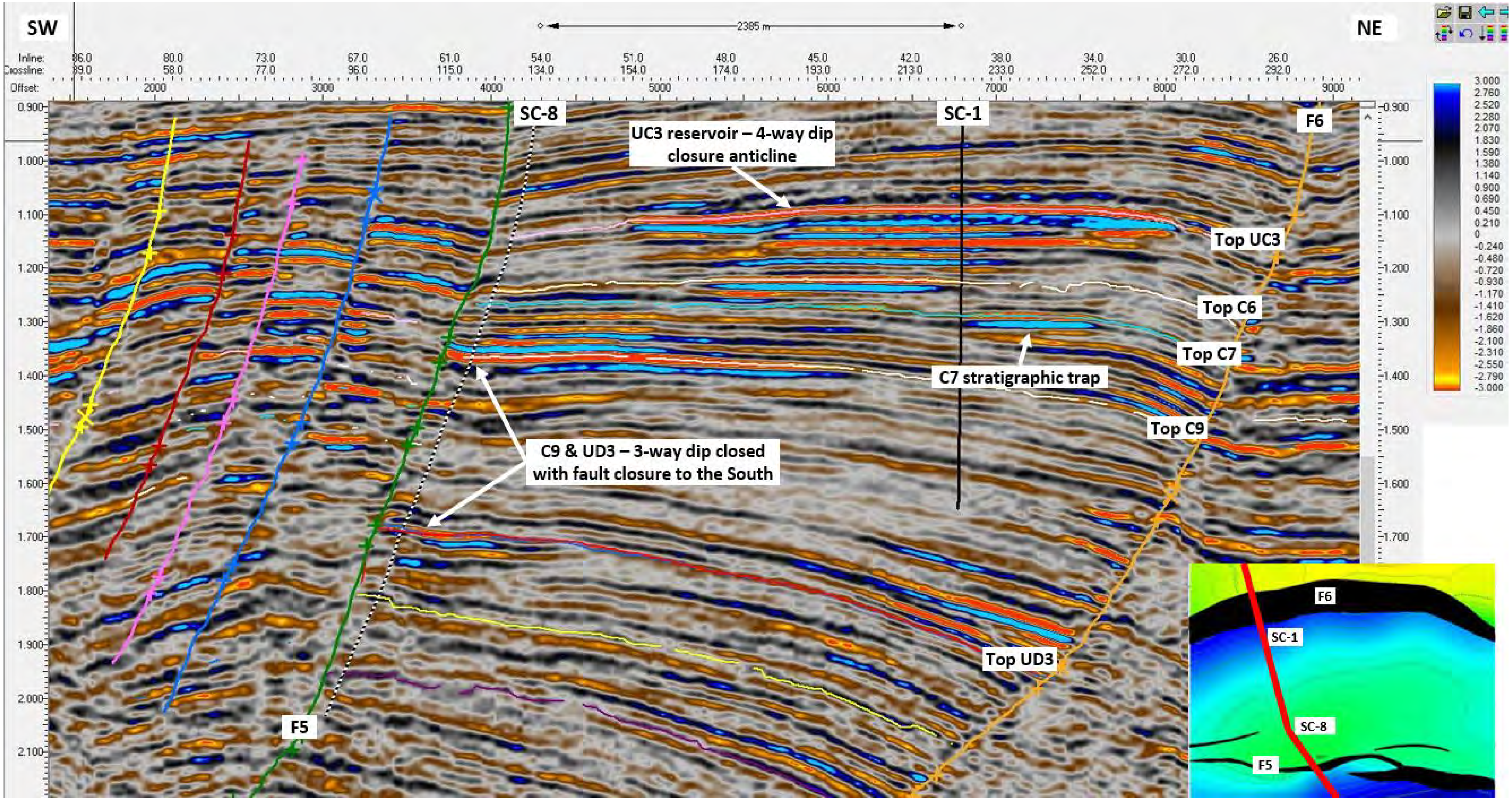


Figure 3-13 SW-NE line through Stubb Creek (Source: Seven, 2019)

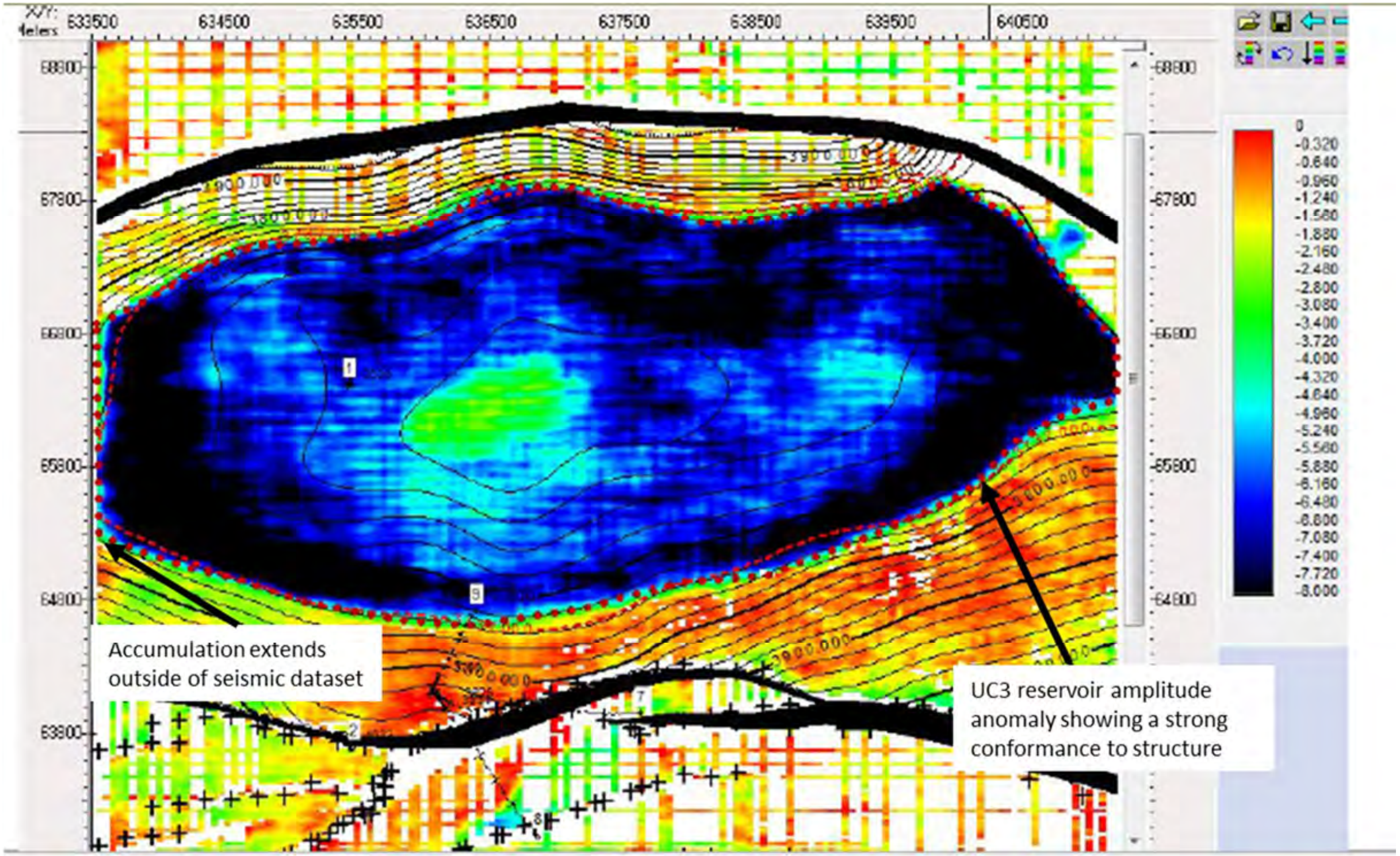


Figure 3-14 Minimum amplitude map (+/-8ms) of the UC3 reservoir (Source: Seven, 2014)

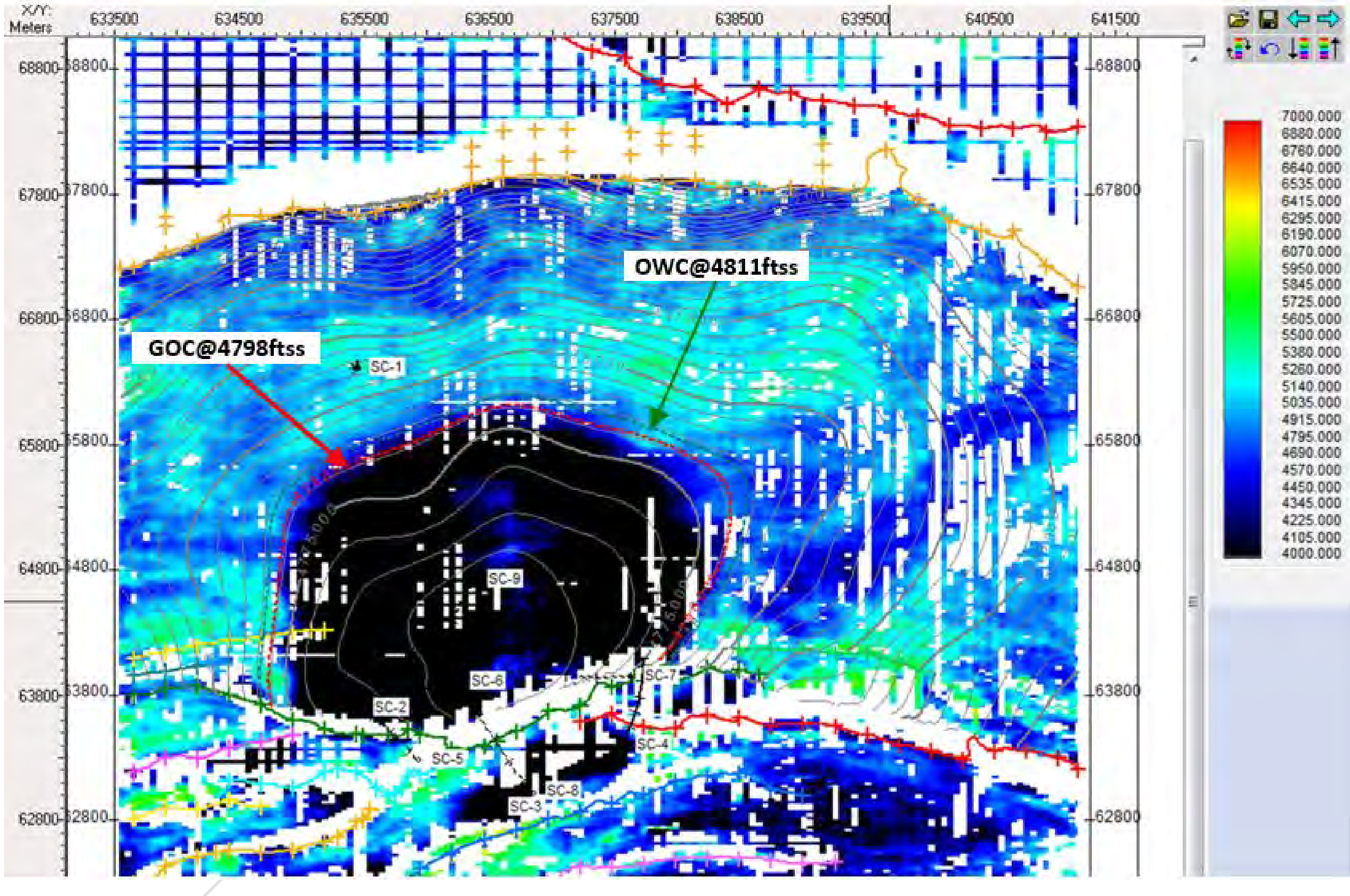


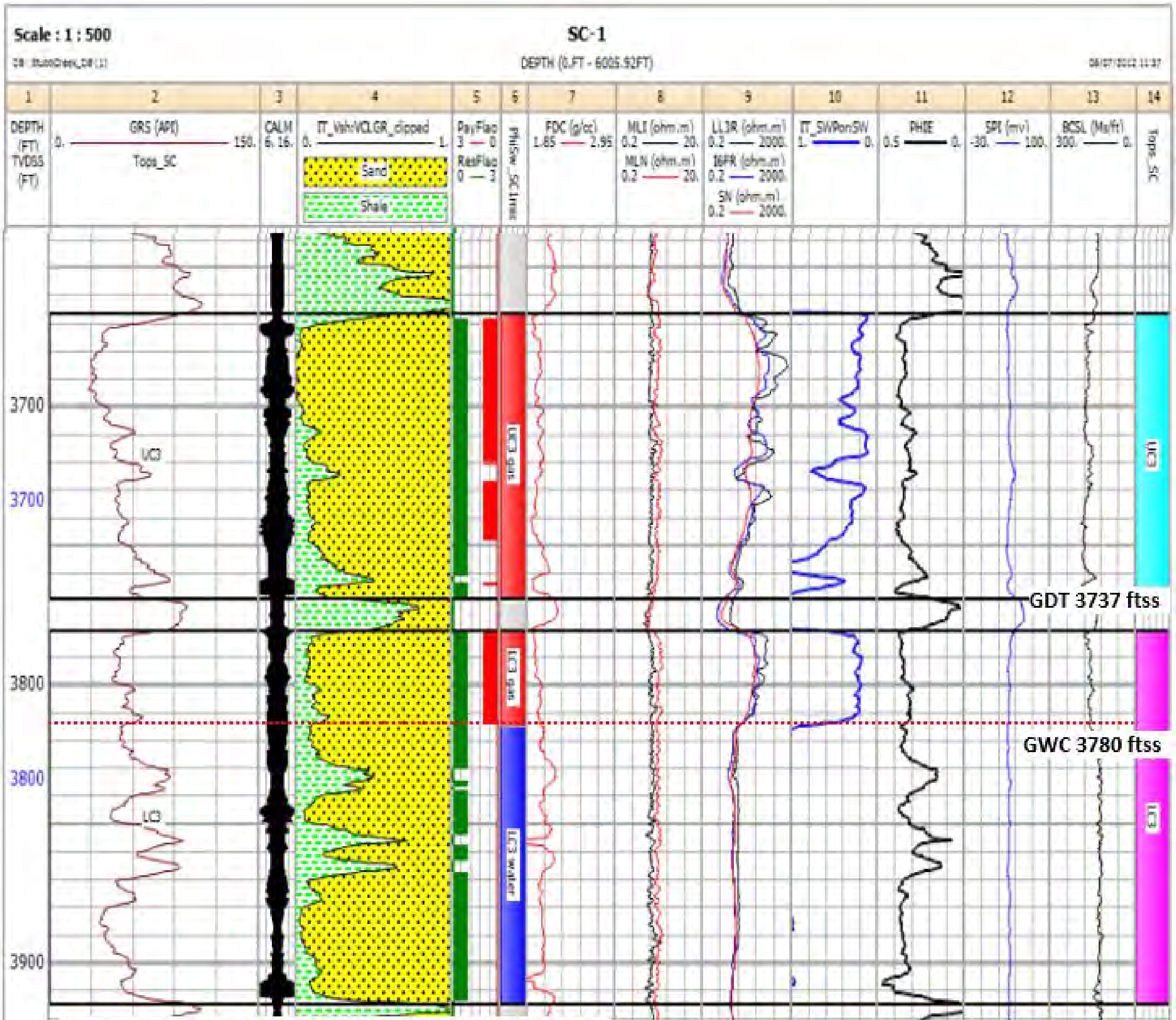
Figure 3-15 C9 Minimum Relative Acoustic Impedance map (Top+8ms) - (Source: Seven, 2014)

The oil in the Upper D3 reservoir is light and good quality; API values are c. 42° with a GOR of 751 scf/bbl. The composition of the non-associated gas in the C sand reservoirs is unknown.

The subsurface team at CGG has completed a thorough Geological and Geophysical QC of the reports supplied by Seven, and using the Kingdom™ project provided have independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by Reservoir Engineering and Petrophysics experts who have also provided inputs for the volumetrics calculations, which were run through a probabilistic Monte Carlo analysis.

3.3.3 Stubb Creek Field Petrophysics

CGG have evaluated the petrophysical data provided for the C and D sands in order to obtain P10, P50 and P90 values for the reservoir properties such as NTG (Net-To-Gross), porosity and hydrocarbon saturations. These were used as inputs for the volumetric calculations. The Volume of Clay (Vcl) was derived using a GR method (Larionov model); porosity was estimated based on the density log or sonic (SC-2 has no density log); while the Simandoux method was used to derive water saturation (Sw). The porosity cut-off of 0.1 and Vcl cut-off of 0.4 used to derive net reservoir intervals are considered to be reasonable. Fluid contacts have been determined from the petrophysical data and these have been used in combination with the DHI's and structural closures in determining the Minimum, P50 and Maximum GRV's. **Figure 3-16** and **Figure 3-17** present results from the petrophysical interpretation for the main gas (C3) and oil (UD3) reservoirs.



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
(PHIE>0.1 & Vcl<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 reservoir average properties
(PHIE>0.1, Vcl<0.4 & Sw<0.5)

Figure 3-16 SC-1 C3 Gas Reservoir Petrophysical interpretation (Source: Seven, 2018)

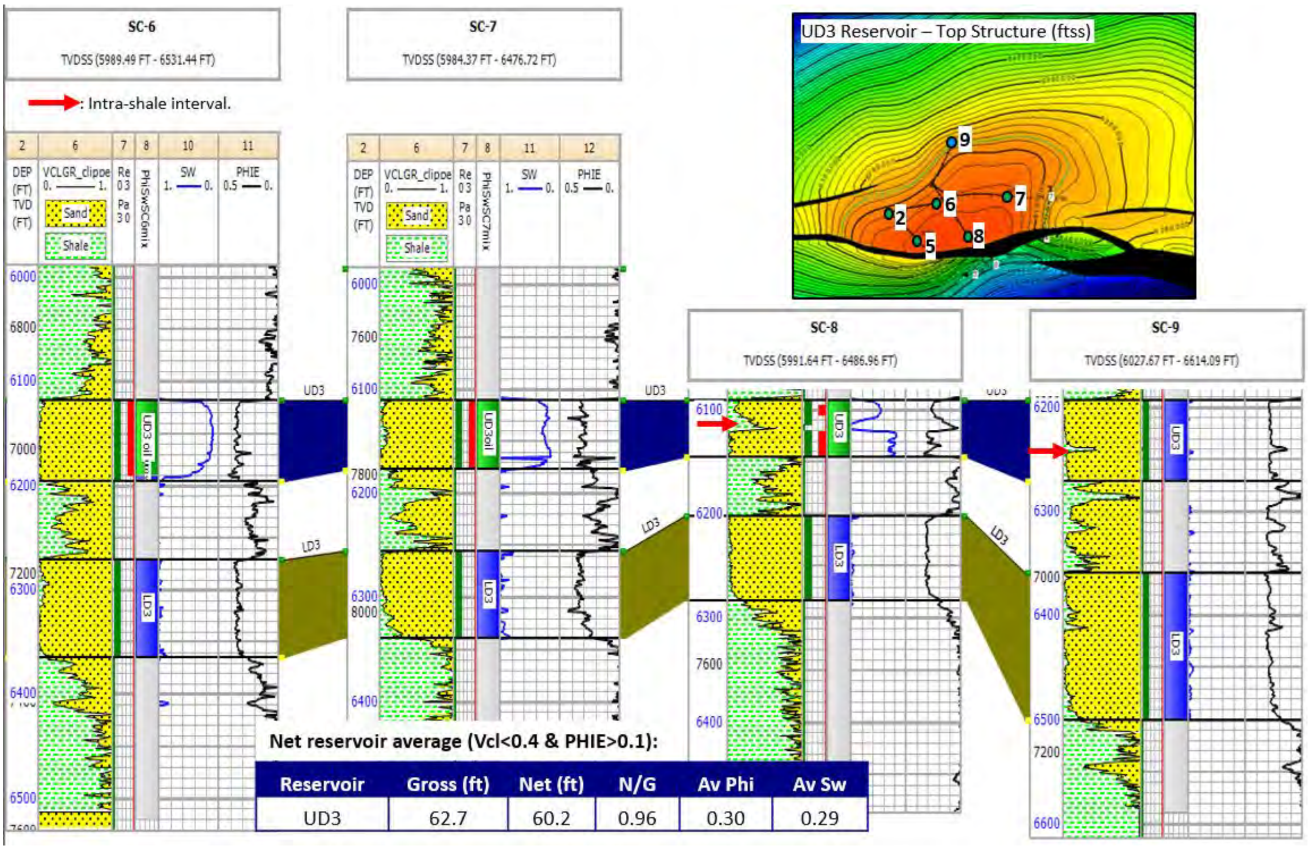


Figure 3-17 Upper D3 Oil Reservoir Petrophysical interpretation (Source: Seven, 2018)

3.3.4 Stubb Creek Field In-Place Volumes

The subsurface team at CGG has independently delineated each of the reservoirs/prospects below in Minimum, P50 and Maximum cases using depth surfaces provided by Seven. The horizons interpretations which have been converted to depth surfaces have been extensively QC'd by CGG and were found to be accurate. However, as previously mentioned, CGG believe that the accuracy of the volumes would be improved by depth migrating the 3D dataset, and subsequently re-interpreting the Gross Rock Volumes of each of the accumulations/prospects. Formation Volume Factors have also been generated by CGG; rock properties have been derived from Seven''s previous work and QC'd by CGG Petrophysics expert. The inputs have been run as a probabilistic Monte Carlo analysis.

Tables 3-4 and 3-5 tabulate in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Reservoir	Gross GIIP (Bscf)		
	P90	**P50**	**P10**
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**

* Arithmetic sum, Total excludes C6 (Prospect) and C8 (too small)

Table 3-4 Stubb Creek Marginal Field GIIP

Reservoir	Gross STOIIP (MMstb)		
	P90	**P50**	**P10**
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/resources due to difficulty in producing the thin oil rim.

** Arithmetic sum

Table 3-5 Stubb Creek Marginal Field STOIIP

4 RESERVOIR ENGINEERING

The objective of this section is to provide an independent assessment of the Reservoir Engineering work performed by Savannah. The following sections summarise the analysis.

4.1 Uquo Marginal Field

4.1.1 Overview

Nine wells have been drilled on the Uquo Field to date, including:

- Four vertical wells: Uquo-1,-2,-3 and -5
- Four deviated wells: Uquo-4,-7,-8 and -9
- One sidetrack of Uquo-5 named Uquo-6
- One sidetrack of Uquo-8 named Uquo-8ST
- One side-track of Uquo-9 named Uquo-9ST

Four wells are currently producing gas and one is a marginal oil producer. The following is a brief summary of the producing wells:

- Uquo-2 is producing gas from the D2.0 reservoir in the Uquo-2 area.
- Uquo-4 is producing gas from the D1.0 reservoir in the Uquo-2 area.
- Uquo-7 and Uquo-8ST are producing gas from the D1.0 reservoir in the Uquo-3 area.
- Uquo-3 is producing oil at marginal rate from the D5.0 reservoir in the Uquo-3 area. There is an opportunity to workover this well and convert it to a gas producer in the D1.3/D1.4 reservoirs.

Savannah plans to drill up to four new wells and performs one recompletion to further develop the field Reserves. Gas from D1.0, D1.3/D1.4 and D2.0 is relatively dry (approx. 97% Methane).

Uquo has been producing gas since Q1 2014. Historical gas production is shown in **Figure 4-1**. Total Daily Contracted Quantity (DCQ) under the three Gas Sales Agreements (GSA) in place is 189.4 MMscfd, and the GSAs have Take or Pay (ToP) provisions within them (set at 80% of DCQ).

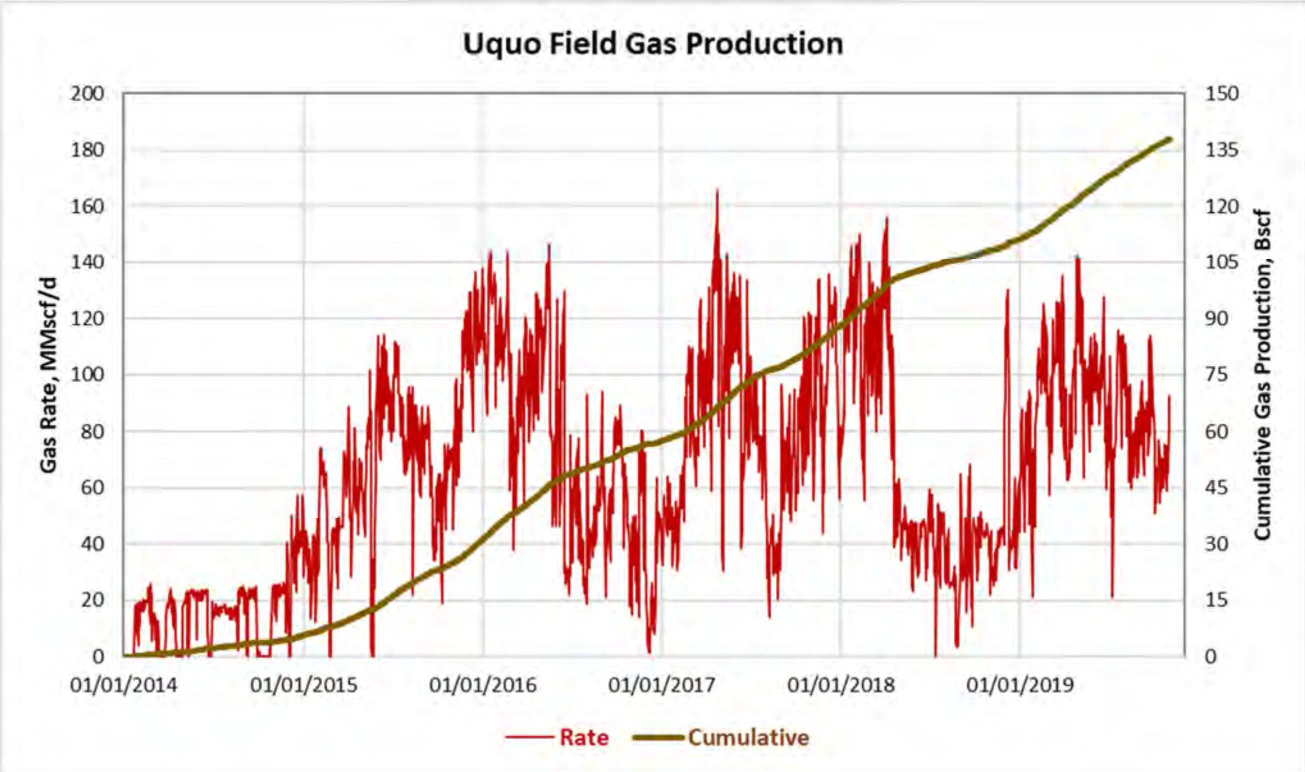


Figure 4-1 Uquo historical gas production as at 1st November 2019

4.1.2 Recoverable volumes

Material balance was used by CGG to verify the Uquo gas in-place volumes, which were estimated by the G&G volumetric method. The estimated total GIIP from material balance for the D1.0 reservoir is 431.5 Bscf. This is in reasonable agreement with the GIIP estimated using the volumetric method presented in **Table 3.1**.

Seven has performed a reservoir simulation study for the Uquo Field. The gas recovery factors estimated by the study were between 75% to 90%. **Table 4.1** shows the range of recovery factors adopted for the Uquo Field. These are based on a high permeability gas reservoir with depletion drive and assuming compression, and are deemed to be reasonable by CGG.

Case	Low	Best	High
Recovery Factor (%)	75.3	79.5	82.3

Table 4-1 Summary of Uquo Field gas recovery factors

Table 4.3 shows a summary of the Gross Technical Reserves calculation. The cumulative production as of 31st October, 2019 is 138.0 Bscf gas and 0.190 MMstb of condensate. Four new gas wells and one recompletion are planned in this field. Economic Reserves net to Savannah derived from the economic model are presented in the Executive Summary.

Area	Reservoir	Well(s)	Comment
Uquo-2	C9.0	-	Contingent Category, not in the development plan
	D1.0	Uquo-4, New Well 1	Producing, new well is planned for 2020
	D1.3/D1.4	WO or New Well 2	Possible recompletion of the new well from D5.0 reservoir
	D2.0	Uquo-2	Producing
	D5.0	New Well 3	
Uquo-3	D1.0	Uquo-7 & Uquo-8ST	Producing
	D1.3/D1.4	WO or New Well 4	Recompletion of well Uquo-3
Uquo NE	C6.0	New Well 5	
	D1.0, D1.5	-	Contingent Category, not in the development plan
Uquo-5	C8.5	-	Contingent Category, not in the development plan

Table 4-2 **Summary of Uquo field Gas reservoirs and producing/planned wells**

Area	Reservoir	Low	Best	High
Uquo-2	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
Uquo-3	D1.0	107.0	204.0	300.0
	D1.3/1.4	22.0	34.5	48.6
Uquo NE	C6.0*	80.0	99.8	124.0
GIIP (Bscf)	**Total****	**592.5**	**813.7**	**1,056.5**
Recovery Factor (%)		75.3	79.5	82.3
EUR (Bscf)		446.5	647.0	870.1
Cum. Prod. (as of 31st Oct. 2019) (Bscf)		138.0	138.0	138.0
Gas Reserves Total (Bscf)		**308.5**	**509.0**	**732.1**
Condensate Reserves Total (MMstb)		0.42	0.69	0.99

* Uquo NE volumes are on-licence only

** Arithmetic sum

Table 4-3 Summary of Uquo Gross Technical Reserves as at 1st November 2019

Figure 4-2 shows 1P, 2P and 3P gas production profiles for Uquo Field based on remaining Low, Best and High case technical reserves respectively as shown in **Table 4-3**. A downtime factor of 7%, equivalent to 25 days per year, is assumed for maintenance and incorporated into the forecasted profiles.

Annual production rates for the Uquo Field are tabulated in **Appendix A.**

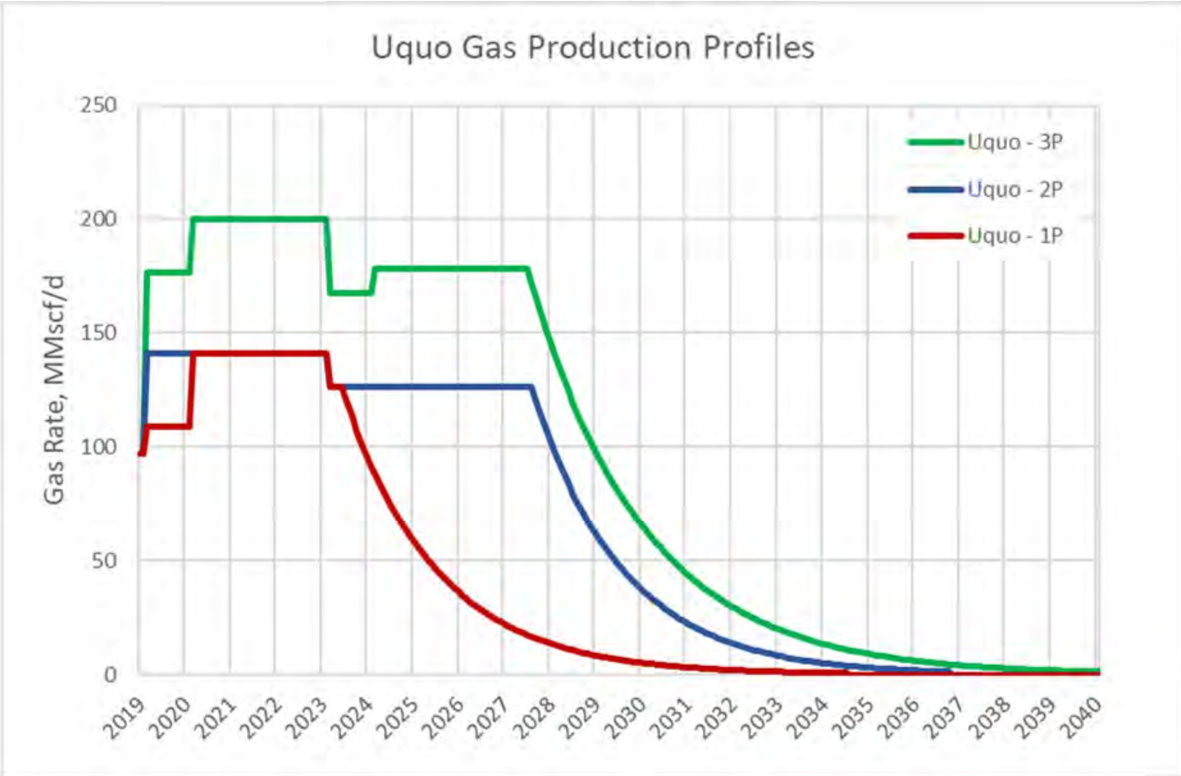


Figure 4-2 Uquo field production forecast profiles (Reserves cases)

Table 4-4 shows a summary of the Gross Contingent Resources. The Contingent Resources are estimated by Material Balance calculation and presented in **Table 3-2**. CGG deem the resulting recovery factors to be reasonable for the expected drive mechanism and fluid properties

Area	Reservoir	Contingent Resources		
		Low/1C	Best/2C	High/3C
Uquo NE	D1.0	27.3	40.4	55.6
	D1.5	2.8	4.2	6.1
Uquo-5	C8.5	11.0	14.3	18.6
Uquo-2	C9.0	17.3	35.9	65.8
Total GIIP (Bscf)		**58.4**	**94.8**	**146.1**
Recovery Factor (%)		77.0	76.4	79.1
Contingent Resources (Bscf)		**45.0**	**72.5**	**115.6**

Table 4-4 Summary of Uquo Gross Contingent Resources

Table 4-5 shows a summary of the Unrisked Gross Prospective Resources in the Uquo Field Licence. The Prospective Resources are estimated by multiplying the recovery factors by the in-place volumes described **Table 3-3**. Recovery factors ranging from 65% to 75% were used.

Prospective Resources	Low/1U	Best/2U	High/3U
GIIP (Bscf)	**558.0**	**826.8**	**1,228.8**
Recovery Factor (%)	65	70	75
Gas Resources (Bscf)	**362.7**	**578.8**	**921.6**

Table 4-5 Summary of Uquo Gross Unrisked Gross Prospective Resources

4.2 Stubb Creek Marginal Field

4.2.1 Overview

Stubb Creek field is producing from three oil wells, the three wells which are on production are: SC-6, SC-7 and SC-8 SS (Short String). Historical oil production since start-up is shown in **Figure 4-3**. Maximum production recorded is 3,491 bopd (gross at separator level) with three wells on-stream. Average production from each well is c. 1,000 bopd.

The processing capacity is capped at 3,000 bopd and it is planned to carry out some debottlenecking in order to increase the production capacity to 5,000 bopd. The upgrade will enable two more wells, namely SC-2 and SC-5, to be put on-stream. These two wells (SC-2 and SC-5) are already drilled and completed in the Upper D3 reservoir.

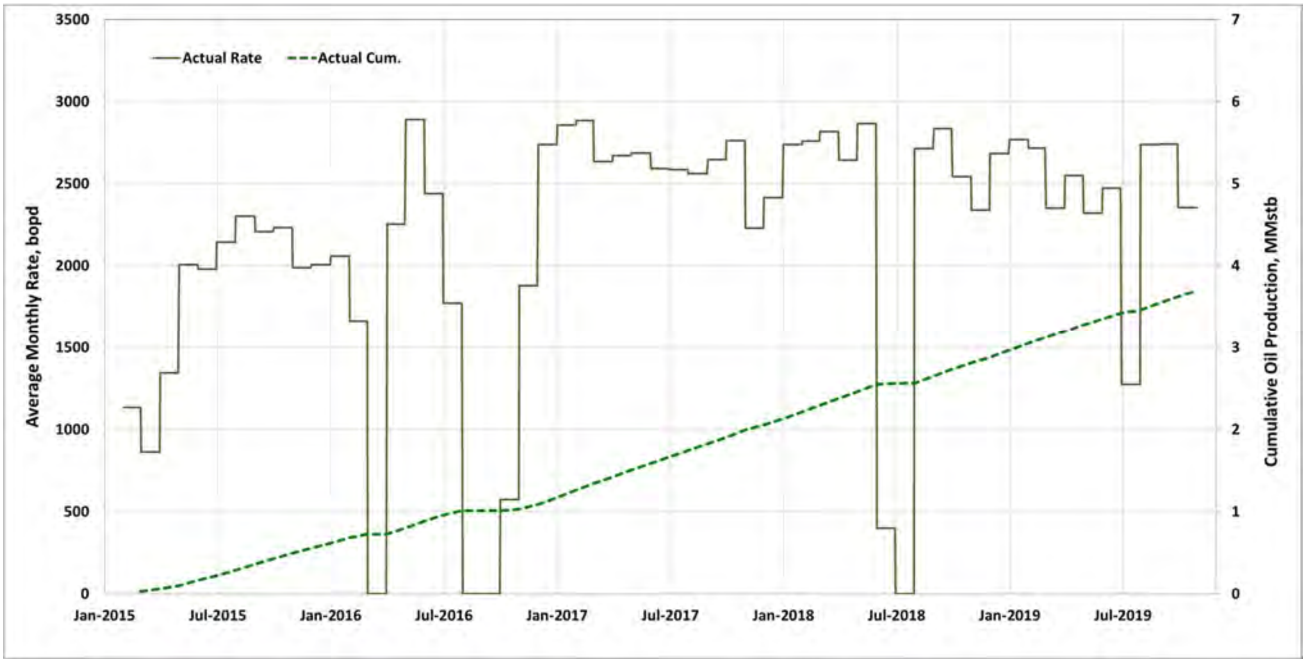


Figure 4-3 Stubb Creek field historical oil production as at 1st November 2019

4.2.2 Drive mechanism

Initial reservoir pressure for the Upper D3 reservoir was 2,719.8 psia at datum depth of 6,189.2 ftss. A static pressure survey has been carried out in December 2015, June 2016 and June 2017. The table below shows the summary of the pressure data at datum depth of 6,189.2 ftss.

Date	Pressure, psia
31/01/2015	2,719.8
31/12/2015	2,712.5
30/06/2016	2,708.8
30/06/2017	2,705.0

Table 4-6 Summary of Stubb Creek Pressure data

The drive mechanism for the UD3 reservoir is strong aquifer drive, which is confirmed by bottom hole pressure surveys on the available wells and the Campbell plot shown in **Figure 4-4**.

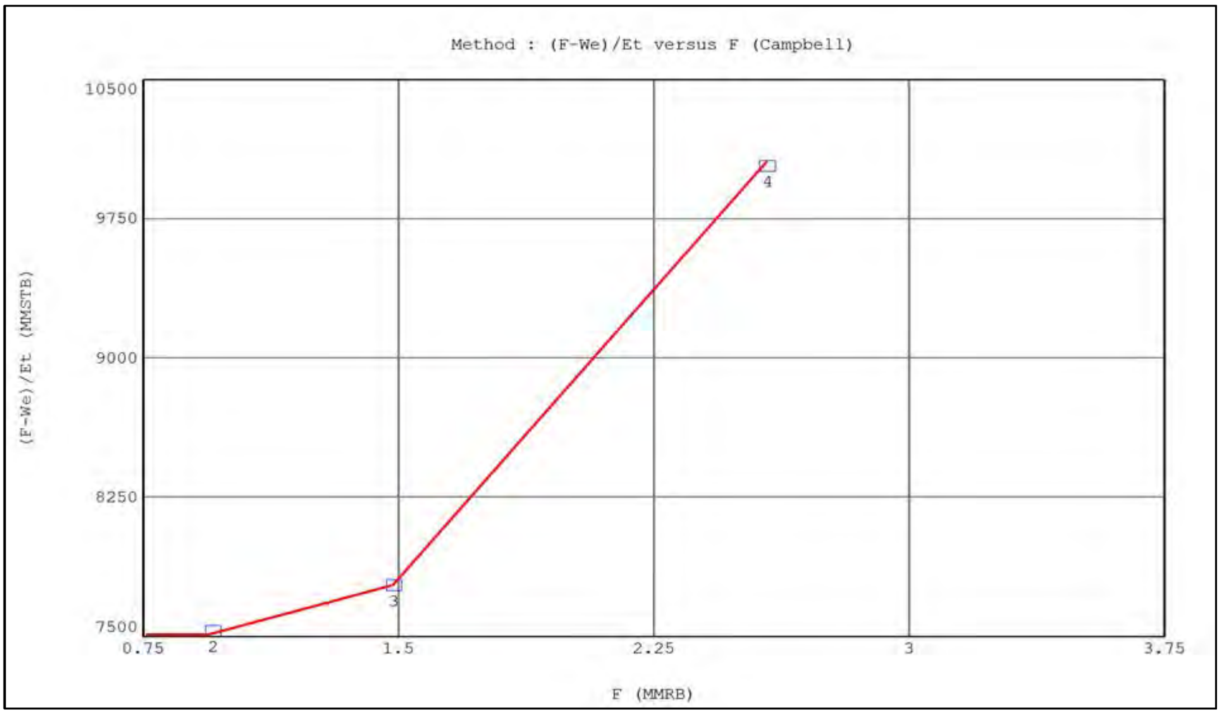


Figure 4-4 Campbell Plot to identify UD3 drive mechanism

Pressure transient analysis performed by Schlumberger for well SC-5, DST-2, test interval: 6,652-6,680 ftMD indicated permeability of 1,420 mD. Another Schlumberger well test report was reviewed for the test interval: 6,693 – 6,738 ftMD at SC-5 well and indicated permeability of 4,900 mD.

Due to high reservoir permeability and strong water drive mechanism the anticipated recovery factors are as shown in **Table 4-7**. CGG deem these recovery factors to be in agreement with regional analogue fields[1].

Case	Low	Best	High
Recovery Factor (%)	40.0	50.0	58.0

Table 4-7 Summary of Stubb Creek field oil recovery factors

The cumulative production as of 31st October, 2019 is 3.70 MMstb of oil.

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[1] SPE 119722 Developing marginal fields in Niger Delta, Uwaga et. Al., Shell Nigeria

4.2.3 Recoverable volumes

Material balance was used to determine the Low, Best and High in-place volumes for the UD3 reservoir. The estimated STOIIP using the material balance method was found to be in a reasonable agreement with the G&G volumetric estimated STOIIP. Therefore, CGG has utilised the G&G volumetrics to estimate the Gross Oil Technical Reserves presented in **Table 4-9**. Economic entitlement Reserves net to Savannah derived from the economic model are presented in the Executive Summary.

	Low	Best	High
STOIIP (MMstb)	**29.9**	**38.9**	**49.6**
Recovery Factor (%)	40	50	58
EUR (MMstb)	12.0	19.5	28.8
Cumulative Production (as of 31st Oct. 2019)	3.7	3.7	3.7
Reserves (MMstb)	**8.3**	**15.8**	**25.1**
GOR (scf/stb)	751		
Solution gas (Bscf)	6.2	11.8	18.8

Table 4-8 Summary of Stubb Creek Field Gross Technical Reserves as at 1st November 2019

Figure 4-5 shows the forecast production profiles for the Stubb Creek Field. The well performance of the producing wells is used to generate production profiles with different plateau rates in each case. It is assumed that the debottlenecking of the production facility will take place in 2021 and the production will increase to 5,000 bopd (Proved +Probable case) by July 2021.

Since production inception, there was minimal downtime due to production facility maintenance or wells' deliverability. However, a downtime factor of 7%, equivalent to 25 days per year, is assumed for maintenance and incorporated into the forecasted profiles.

It is also assumed that after the debottlenecking of the production facility, a pre-downtime rate value of 4,500, 5,000, and 5,500 bopd of processing capacity will be achieved for the 1P, 2P, and 3P scenarios, respectively. This rate will be achieved by opening all the available wells namely SC-2, SC-5, SC-6, SC-7 and SC-8SS.

It should be noted that 12ft of oil exists in the C9.0 reservoir, however due to the limited thickness of the oil leg CGG believes recovery would be challenging. Therefore, no oil Reserves or Resources have been attributed for the C9.0 reservoir.

Annual production rates for the Stubb Creek Field are tabulated in **Appendix A**.

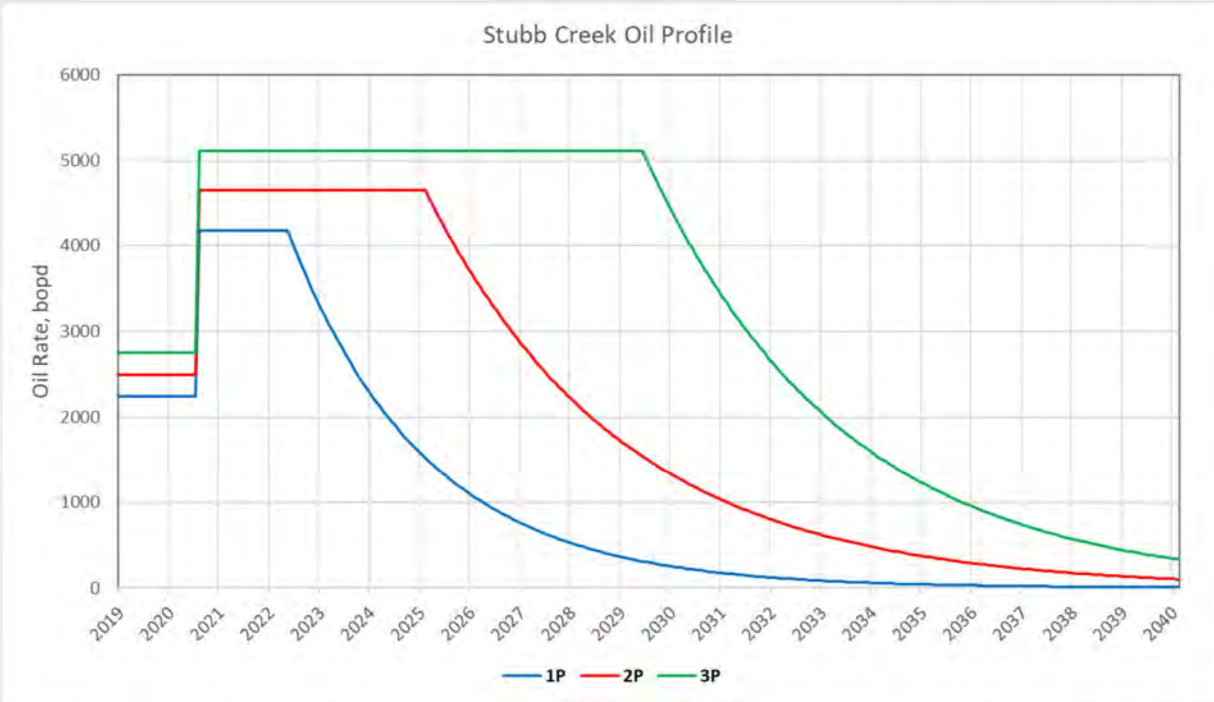

Figure 4-5 Stubb Creek production forecast profiles

A summary of the Gross Gas Contingent Resources is shown in Table 4-9. The Contingent Gas Resources are calculated by multiplying in-place volumes estimated in Table 3.4 by a range of recovery factors based on simulation studies and analogue fields.

Contingent Resources	Low/1C	Best/2C	High/3C
GIIP (Bscf)	**482.4**	**656.2**	**819.9**
Recovery Factor (%)	76	78.5	83
Gas Resources (Bscf)	**364.9**	**515.3**	**680.3**

Table 4-9 Summary of Stubb Creek Field Gross Contingent Resources

A summary of Unrisked Gas Prospective Resources is shown below in **Table 4-10**. The Prospective Resources are calculated by multiplying in-place volumes estimated in **Table 3-4** by a range of recovery factors based on analogue fields.

Prospective Resources	Low/1U	Best/2U	High/3U
GIIP (Bscf)	**13.8**	**19.8**	**27.8**
Recovery Factor (%)	65	70	75
Gas Resources (Bscf)	**9.0**	**13.9**	**20.9**

Table 4-10 Summary of Stubb Creek Field Gross Unrisked Prospective Resources

Figure 4-6 shows Reserves and Contingent Resources profiles for the Uquo and Stubb Creek fields.

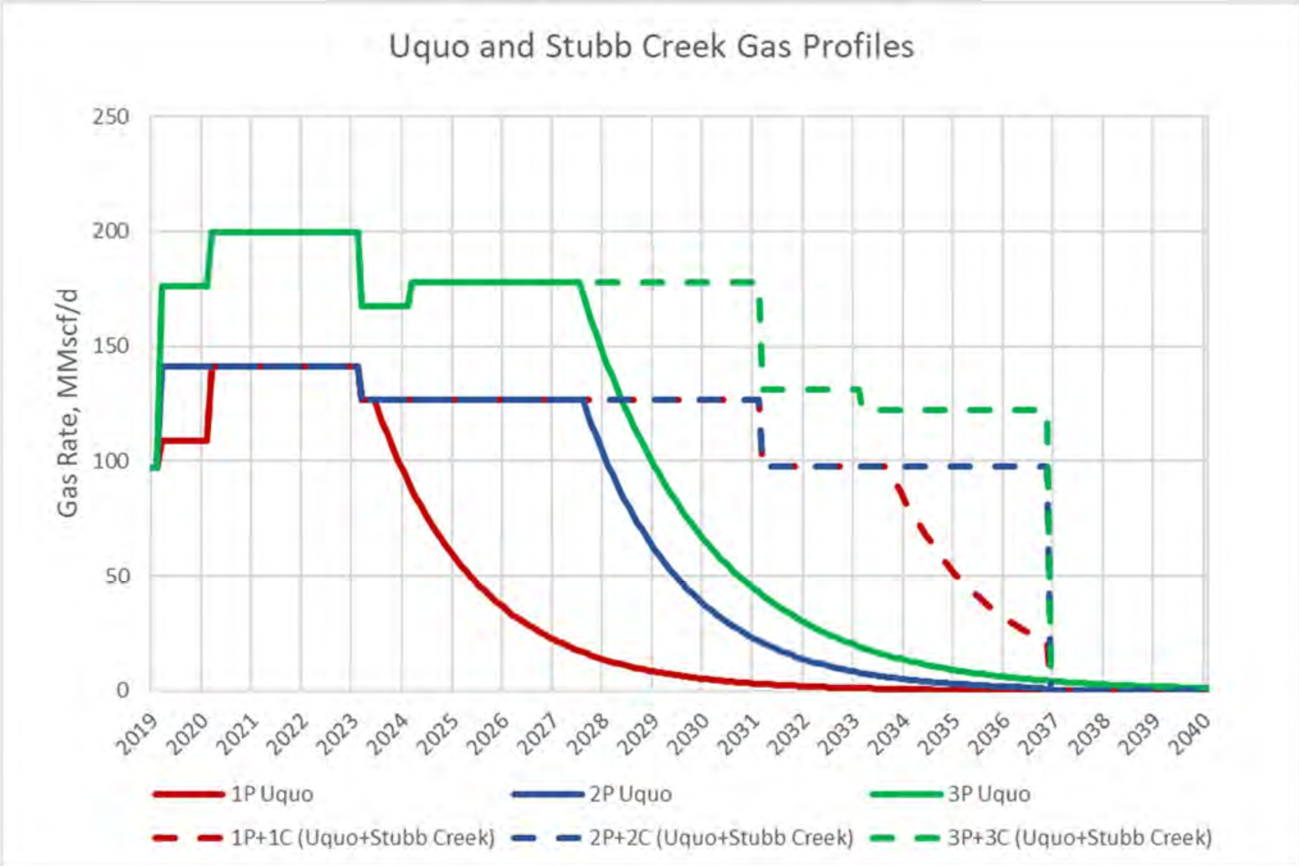

Figure 4-6 Uquo and Stubb creek Fields production forecast profiles (Reserves and Contingent Resources cases)

Annual production rates for all cases are tabulated in **Appendix A**.

5 FACILITES AND COSTS

This section presents details of the existing facilities and future development plans for the Uquo, Stubb Creek Fields, and Accugas Midstream Business. All costs are presented in 2019 terms.

5.1 Uquo Field

5.1.1 Existing facilities

Dedicated in-field flowlines transport produced gas individually from the producing wells owned by SUGL to a Central Processing Facility (CPF) owned by Accugas. The gas from the Uquo Field is relatively dry (approximately 97% methane).

5.1.2 Development plans

The proposed development plan for Uquo consists of drilling four additional gas wells, and the recompletion of one well (Uquo-3). An existing well will also be subject to a work-over.

Table 5.1 presents the work plan assumed for the 1P, 2P and 3P Reserves cases. All Reserves cases assume the same work elements but with different timings.

Year	1P	2P	3P	1C	2C	3C
2020	1 gas well and 1 recompletion	1 gas well and 1 recompletion	1 gas well and 1 recompletion			
2021	1 gas well	1 gas well	1 gas well			
2022	2 gas wells	1 gas well	1 gas well			
2023		1 gas well	1 gas well			
2024				2 gas wells		
2025						
2026						
2027						
2028					1 gas well	1 gas well
2029					1 gas well	1 gas well

Table 5-1 Uquo – Reserves and Contingent Resources Well Schedules

The estimated cost of each gas well is $18MM, comprising $15MM for the well itself and $3MM for the flowlines. The recompletion of Uquo-3 is estimated to be $7.2MM. The total cost is estimated to be approximately $80MM for each Reserves case.

An additional two wells costing $18MM each are assumed for the Contingent Resources cases.

These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

5.1.3 Operating costs

Operating costs for Uquo Field are assessed to be $6.5MM per year, with an additional $8.5MM in 2020 for the Uquo-7 workover.

5.1.4 Decommissioning costs

Decommissioning costs for the Reserves cases are estimated to be $20MM (2019 terms) for plugging and abandoning the wells, and removing the flowlines.

5.2 Stubb Creek Field

5.2.1 Existing facilities

Dedicated in-field flowlines from each well transport production to a 3,000 bopd Early Production Facility (EPF). From the EPF crude is transported via a 23 km 6 inch pipeline to the FUN manifold, and then to the Qua Iboe Terminal. A 31 km 6 inch pipeline has also been constructed to transport produced associated gas to the Uquo CPF, which is now operational and preventing flaring.

5.2.2 Development plans

The proposed Oil development plan for Stubb Creek consists of:

- De-bottlenecking the existing production facility, to increase gross capacity from 3,000 to 5,000 bopd (2021)
- Bringing on stream the two wells already drilled (2021)
- Drilling a water disposal well (2021)

The latter may be needed, based on evidence of strong aquifer support, although there is no water production at the current time.

Total capex for the above development plan is estimated to be $28MM comprising $15MM for the water well and $13MM for the production facility upgrade and water handling facilities.

For the Contingent Resources gas cases, six new wells are assumed, with an estimated total cost of $108MM.

Year	1C	2C	3C
2025	1 gas well		
2026			
2027	1 gas well		
2028	2 gas wells		
2029	1 gas well		
2030	1 gas well	1 gas well	1 gas well
2031			
2032		1 gas well	
2033			1 gas well
2034		1 gas well	
2035			1 gas well
2036		1 gas well	

Table 5-2 Stubb Creek - Contingent Gas Resources Wells Schedule

These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

5.2.3 Operating costs

Operating costs for the oil operations are $6.5MM per year, and an additional $2MM per year for the Contingent Resources gas case. There is also a crude handling charge of $1.37/bbl for use of the Qua Iboe Terminal.

5.2.4 Decommissioning

Decommissioning costs for the Reserves case are estimated to be $6MM (2019 terms) for plugging and abandoning the wells, and removing the flowlines and production facility.

5.3 Accugas

Accugas owns and operates the midstream gas facilities associated with the Uquo and Stubb Creek Fields. The principal assets comprise the Uquo CPF and the export pipelines.

The Uquo CPF, which is owned and operated by Accugas, consists of two process trains; each with a nameplate capacity of 100 MMscfd. The CPF provides the following services:

- hydrocarbon and water dew-point control,
- condensate stabilisation,
- crude processing,
- power generation

Gas from the CPF is currently exported through the following pipelines owned and operated by Accugas:

- a 62 km 18 inch pipeline via the Ikot Abasi Gas Receiving Facility to the Ibom power station
- a 63 km 24 inch pipeline via the Oron Tie-in to the Calabar Junction and then to the Calabar power station and the Unicem plant

Condensate is exported from the CPF via an 8 km 4 inch oil pipeline to the FUN manifold and then via a 2 km 10 inch oil pipeline to the Exxon Mobil operated Qua Iboe Terminal. Accugas also owns the 128 km East Horizon gas pipeline, which was originally constructed as the main export pipeline to Calabar. The FUN manifold is owned by a JV of the Uquo, Stubb Creek and Qua Iboe Marginal Field Operators.

Locations and details of the CPF and the pipelines are provided in **Figure 5-1**.

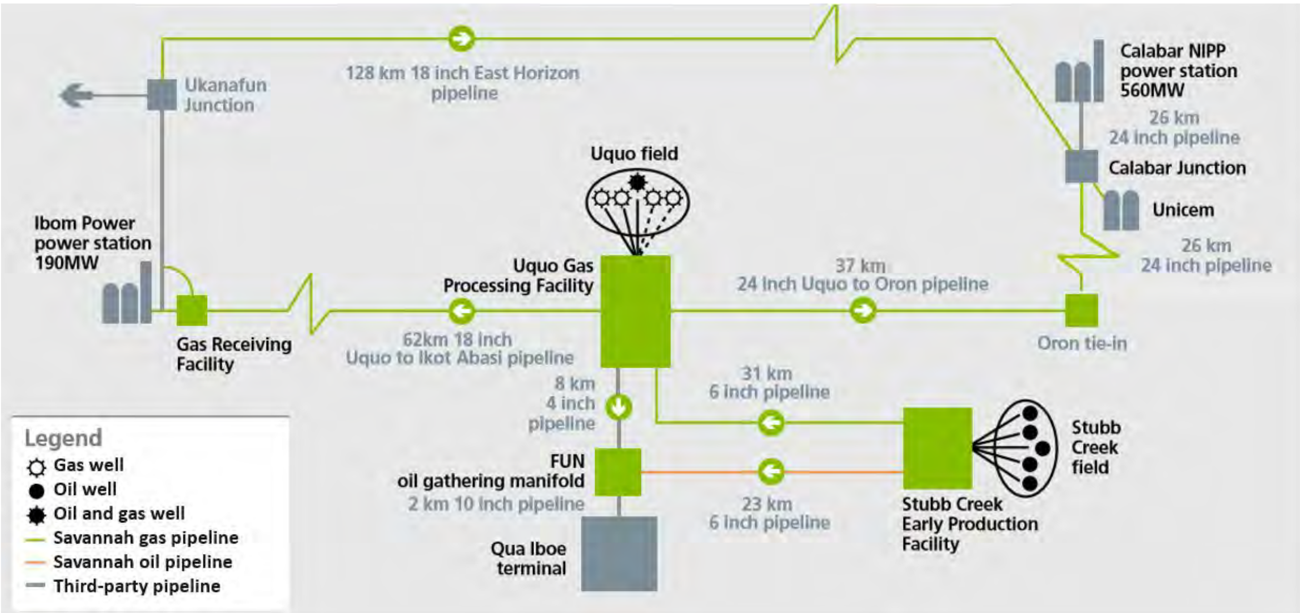

Figure 5-1 Uquo, Stubb Creek, Accugas and associated Infrastructure

5.3.1 Development costs

The CPF currently processes gas from the Uquo Field, but in the future it is planned to install compression facilities and to process gas from other fields, including Stubb Creek.

The planned capex for Accugas totals \$105MM comprising \$59MM for pipelines, \$45MM for compression and \$0.7MM of other costs. Compression is planned for 2023 (two stages) for the Proved case, 2026 (1st stage) and 2027 (2nd stage) for the Proved+Probable case, and 2025 (1st stage) and 2027 (2nd stage) for the Proved+Probable+Possible case

5.3.2 Operating costs

Operating costs are estimated at \$20MM in 2020, reducing to \$15MM thereafter without non-recurring costs incurred in 2020. In addition, there is a crude handling charge of \$1.37/bbl for use of the Qua Iboe Terminal. Accugas will also charge a processing fee of \$4.25/bbl to Frontier on any future oil production, although this has not been included in the valuation at this stage.

5.3.3 Decommissioning costs

Decommissioning costs for the Reserves case are estimated to be \$79MM (2019 terms) for removal of the facilities and land re-instatement.

6 ECONOMIC EVALUATION

6.1 Methodology

Net Present Values (NPVs) and economic Reserves have been calculated using Savannah's Excel™ integrated economic model of the Uquo and Stubb Creek Marginal Fields, and the Accugas Midstream business. The model has been subject to a high level review by CGG, and found to be in agreement with the fiscal and commercial terms applicable to the licences.

6.2 Paying and Revenue interests

Savannah has an 80% participating interest in the Uquo gas project via an 80% interest in SUGL.

Savannah has a 51% participating interest in the Stubb Creek Marginal Field via a 100% interest in UERL. The company's paying interest in the field is 20% for oil and 50% for gas, and the profit interest is 35% for oil and 60% for gas.

Savannah has an 80% participating interest in the Accugas Midstream Business.

6.3 Fiscal terms

It is assumed that the current Nigerian Marginal Field tax terms apply to Uquo and Stubb Creek Fields.

Accugas is assumed to be subject to standard Nigerian Corporate Income Tax.

The key features of the fiscal regime for Uquo and Stubb Creek assumed in the model are tabulated below.

Oil Royalty	0 – 2,000 bpd	2.5%
	2,001 – 5,000 bpd	2.5%
	5,001 – 10,000 bpd	7.5%
	10,001 – 15,000 bpd	12.5%
	> 15,001 bpd	18.5%
Gas Royalty	7%	
Overriding Royalty (oil)	0 – 2,000 bpd	2.5%
	2,001 – 5,000 bpd	3.0%
	5,001 – 10,000 bpd	5.5%
	10,001 – 15,000 bpd	7.5%
	> 15,001 bpd	TBD
Education tax	2.0%	
NDDC levy	3.0%	
Petroleum Profits Tax (PPT)	85% (Uquo tax holiday to end Nov 2018, Stubb Creek 65.75% to end 2019)	
CIT	30%	
Capital allowances	100% on exploration, development and the first two appraisal wells. 20% for years 1-4, then 19% for year 5 on other capex. Capital allowances used in any given year are restricted to 85% of assessable profit.	
Profit Investment Allowance (PIA)	5.0%	

Table 6-1 Summary of Fiscal Terms

Taxes have been adjusted to allow for brought forward capital allowances and tax losses.

6.4 Oil prices

Oil production from Stubb Creek is sold to ExxonMobil at the Qua Iboe terminal. It is assumed that the price achieved is at a $1.25/bbl premium to Brent based on historic sales for 2018 and 2019. Condensate is commingled with processed crude and sold at the same premium to Brent.

The Brent price assumed is based on the forward Brent strip as of 29th October 2019 until the end of 2026 and thereafter escalated at 2% per year. The Brent price assumed by year is tabulated below.

Year	$/bbl
2019	60.2
2020	59.3
2021	57.4
2022	56.9
2023	57.1
2024	57.7
2025	58.2
2026	58.9
2027	+2% pa

Table 6-2 Brent oil price assumed (nominal)

6.5 Gas prices

Gas from the Uquo Field is sold to Accugas under the Upstream GSA (Gas Sales Agreement). The contract runs until the end of December 2028, and thereafter extendable to the end of Uquo Field life. The DCQ (Daily Contracted Quantity) is 189.4 MMscfd with a ToP of 80% of the DCQ. The yearly base gas price for each year of the contract is tabulated below. The base price A transfers to base price B at the later of two years from the effective date or after cumulative production under the agreement has reached 110 Bscf.

Year	Base Price A (unindexed) $/Mscf	Base Price B (unindexed) $/Mscf
2019	1.25	-
2020	1.31	-
2021	1.37	1.57
2022	1.44	1.64
2023	1.51	1.72
2024	1.58	1.80
2025	1.58	1.80
2026	1.58	1.80
2027	1.58	1.80
2028	1.58	1.80

Table 6-3 Details of Upstream Gas Sales Agreement

These prices are adjusted by a “Weighted Average Index” based on the PPI-US/CPI-US adjustment calculated under the Downstream GSAs. The upstream nominal gas price assumed in the economic model is tabulated below.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gas Price ($/mcf)	1.28	1.37	1.61	1.69	1.80	1.82	2.31	2.35	2.39	2.42

Table 6-4 Upstream nominal gas price assumed in the economic model

Accugas sells processed gas under Downstream GSAs to the Ibom and Calabar power plants, and to the Unicem cement factory. The key terms of each GSA are tabulated below.

Contract term	Calabar Power Plant	Unicem Cement Plant	Ibom Power Plant
Length of contract	20 years	20 years	10 years
Contract end	Sept 2037	Dec 2031	Dec 2023
DCQ	131.0 MMscfd	38.7 MMscfd	19.7 MMscfd
Take or Pay (ToP)	80% of DCQ	80% of DCQ	80% of DCQ
Gas price	2019 $3.53/Mscf increasing in steps to $5.04/Mscf in 2024 All indexed to US PPI	$5.0/Mscf (all years)	2019 $2.18/Mscf Thereafter escalated with US CPI

Table 6-5 Details of Downstream Gas Sales Agreements

The average downstream nominal gas price assumed by year across the three contracts in the economic model is tabulated below.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Gas Price ($/mcf)	3.88	4.07	4.27	4.52	4.98	5.06	5.13	5.21	5.30	5.38

Table 6-6 Downstream average nominal gas price assumed in the economic model

6.6 Other assumptions

The following assumptions have also been used by CGG.

Parameter	Value
Discount Rate	10%
Discount Methodology	Monthly
Cost /Price Inflation	2% per annum
Valuation Date	1st November 2019

Table 6-7 Economic Parameters

6.7 Economic results

6.7.1 Upstream Assets

The Net Present Values (NPV) of future cash flows derived from the exploitation of the reserves are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes. The NPVs of Uquo are based on the gas sold under the GSAs and its associated condensate, while Stubb Creek is solely based on oil production.

NPV10 ($USMM) of Reserves Net to Savannah			
	Proved	**Proved & Probable**	**Proved, Probable & Possible**
Uquo (gas and condensate)	139.2	227.7	322.1
Stubb Creek oil	38.1	56.7	72.0
Total	**177.2**	**284.4**	**394.1**

Table 6-8 NPV10 ($USMM) of Reserves Net to Savannah as at 1st November 2019

Sensitivities have been calculated for total NPV for variations in oil price, capex and opex. The results of this analysis are tabulated below for the Proved & Probable case.

NPV10 ($USMM) Net to Savannah			
	Uquo	**Stubb Creek**	**Total**
Base case (Proved+Probable)	227.7	56.7	**284.4**
Oil price -25%	223.2	46.7	**269.9**
Oil Price +25%	232.2	65.8	**298.0**
Capex +25%	216.7	56.0	**272.7**
Capex -15%	234.3	57.2	**291.5**
Opex +25%	214.3	55.2	**269.5**
Opex -15%	235.9	57.7	**293.7**

Table 6-9 Proved+Probable NPV10 ($USMM) Sensitivities as at 1st November 2019

6.7.2 Midstream Assets (Accugas)

The Net Present Values (NPV) of the future cash flows accruing to the Accugas Midstream Business have been extracted from Savannah's integrated economic model and are tabulated below for the base case (ToP). The model has been subject to a high level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for the Accugas Midstream Business (100%) and for Savannah's net 80% interest after deduction of Royalties and Taxes.

Case	Accugas (100%)	Net to Savannah
Base Case (ToP)	840.9	672.8

Table 6-10 Accugas NPV10s ($USMM)

The values stated assume that the ToP volumes detailed in the respective gas sales agreements described in Section 6.5 are sold to the respective downstream buyers. These sales volumes are initially sourced from Uquo, with additional feedstock expected to come from Stubb Creek, and potentially other sources such as third party gas fields.

It should be noted that there are no gas Reserves or Resources associated with Accugas.

7 APPENDIX A: PRODUCTION PROFILES

Gross Production Profiles: Uquo Field

	Uquo Field											
	Condensate (bopd)			Gas (MMscf/d)			Condensate (bopd)			Gas (MMscf/d)		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2019	131.6	131.6	131.6	96.9	96.9	96.9	-	-	-	-	-	-
2020	147.6	191.7	239.6	108.7	141.1	176.4	-	-	-	-	-	-
2021	191.7	191.7	271.2	141.1	141.1	199.7	-	-	-	-	-	-
2022	191.7	191.7	271.2	141.1	141.1	199.7	-	-	-	-	-	-
2023	191.7	191.7	271.2	141.1	141.1	199.7	-	-	-	-	-	-
2024	153.1	171.7	227.3	112.7	126.5	167.4	18.6	-	-	13.7	-	-
2025	96.5	171.7	241.6	71.0	126.5	177.9	56.5	-	-	41.6	-	-
2026	59.4	171.7	241.6	43.7	126.5	177.9	36.6	-	-	26.9	-	-
2027	36.6	171.7	241.6	26.9	126.5	177.9	22.3	-	-	16.4	-	-
2028	22.5	160.2	224.4	16.6	118.0	165.2	13.5	11.5	17.2	10.0	8.5	12.7
2029	13.9	102.8	155.5	10.2	75.7	114.5	8.2	69.0	86.1	6.1	50.8	63.4
2030	8.5	62.1	104.5	6.3	45.8	76.9	5.0	75.9	110.1	3.7	55.9	81.1
2031	5.3	37.6	70.2	3.9	27.7	51.7	3.1	46.3	75.6	2.2	34.1	55.6
2032	3.2	22.7	47.2	2.4	16.7	34.7	1.9	28.2	50.9	1.4	20.8	37.5
2033	2.0	13.7	31.7	1.5	10.1	23.3	1.1	17.2	34.3	0.8	12.6	25.3
2034	1.2	8.3	21.3	0.9	6.1	15.7	0.6	10.5	23.1	0.4	7.7	17.0
2035	0.4	5.0	14.3	0.3	3.7	10.5	-	6.4	15.6	-	4.7	11.5
2036	-	3.0	9.6	-	2.2	7.1	-	3.9	10.5	-	2.9	7.7
2037	-	1.3	6.5	-	1.0	4.8	-	0.9	6.6	-	0.7	4.8
2038	-	-	4.3	-	-	3.2	-	-	-	-	-	-
2039	-	-	2.9	-	-	2.1	-	-	-	-	-	-
2040	-	-	2.0	-	-	1.4	-	-	-	-	-	-

Gross Production Profiles: Stubb Creek Field

	Stubb Creek Field											
	Oil (bopd)			Gas (MMscf/d)			Condensate (bopd)			Gas (MMscf/d)		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2019	2,250	2,500	2,750	1.7	1.9	2.1	-	-	-	-	-	-
2020	2,250	2,500	2,750	1.7	1.9	2.1	-	-	-	-	-	-
2021	3,218	3,575	3,933	2.4	2.7	3.0	-	-	-	-	-	-
2022	4,185	4,650	5,115	3.1	3.5	3.8	-	-	-	-	-	-
2023	3,832	4,650	5,115	2.9	3.5	3.8	-	-	-	-	-	-
2024	2,700	4,650	5,115	2.0	3.5	3.8	-	-	-	-	-	-
2025	1,871	4,650	5,115	1.4	3.5	3.8	27.7	-	-	13.8	-	-
2026	1,296	4,148	5,115	1.0	3.1	3.8	111.6	-	-	55.8	-	-
2027	897	3,214	5,115	0.7	2.4	3.8	166.3	-	-	83.1	-	-
2028	622	2,491	5,115	0.5	1.9	3.8	199.8	-	-	99.9	-	-
2029	431	1,930	5,115	0.3	1.4	3.8	220.4	-	-	110.2	-	-
2030	298	1,495	4,873	0.2	1.1	3.7	233.0	49.6	39.8	116.5	24.8	19.9
2031	207	1,159	3,845	0.2	0.9	2.9	240.7	129.5	141.2	120.3	64.7	70.6
2032	143	898	2,977	0.1	0.7	2.2	187.7	120.3	118.2	93.9	60.1	59.1
2033	99	696	2,304	0.1	0.5	1.7	190.6	149.7	165.5	95.3	74.9	82.7
2034	69	539	1,784	0.1	0.4	1.3	183.4	167.6	178.7	91.7	83.8	89.3
2035	48	418	1,381	0.0	0.3	1.0	123.0	178.4	200.1	61.5	89.2	100.0
2036	33	324	1,069	0.0	0.2	0.8	76.3	185.0	214.4	38.2	92.5	107.2
2037	23	251	828	0.0	0.2	0.6	37.5	143.1	167.4	18.8	71.6	83.7
2038	16	194	641	0.0	0.1	0.5	-	-	-	-	-	-
2039	11	151	496	0.0	0.1	0.4	-	-	-	-	-	-
2040	8	117	384	0.0	0.1	0.3	-	-	-	-	-	-

8 APPENDIX B: DEFINITIONS

8.1 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 June 2018, 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 (June 2018) are presented below.

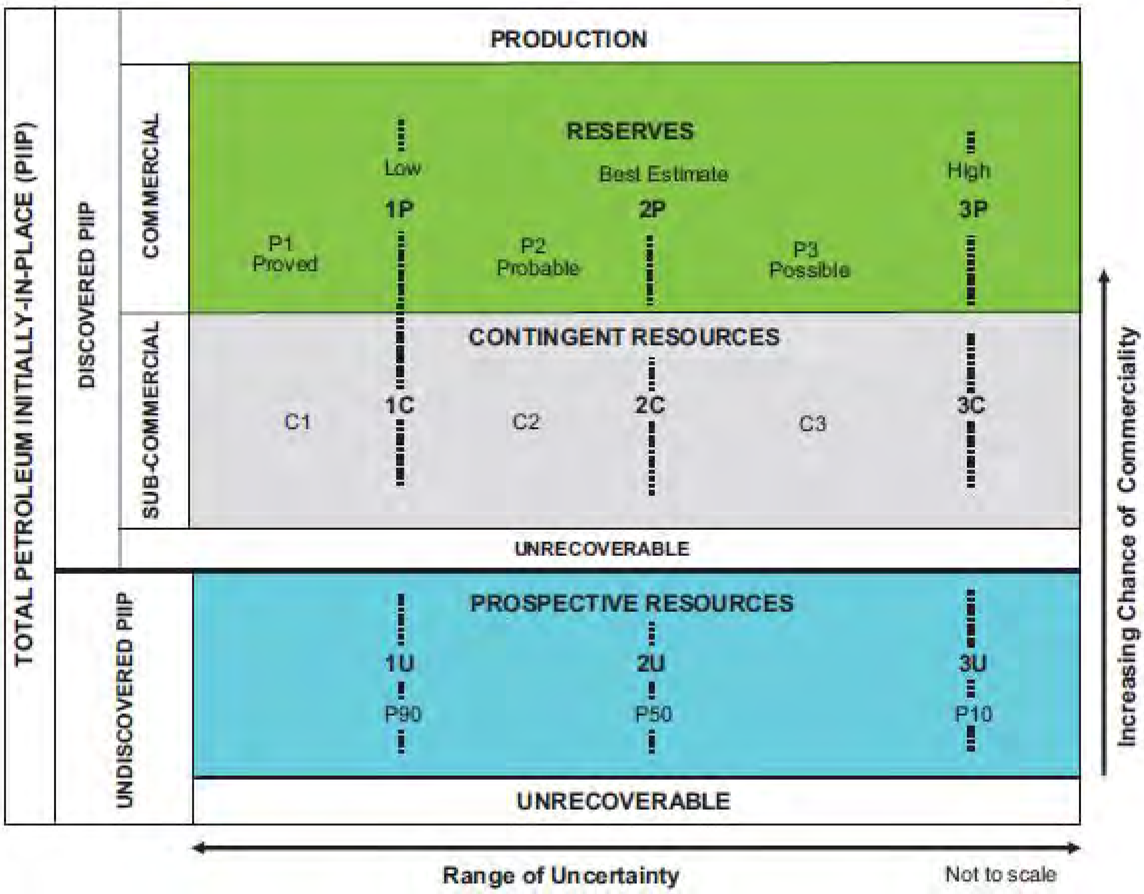

Figure 8-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

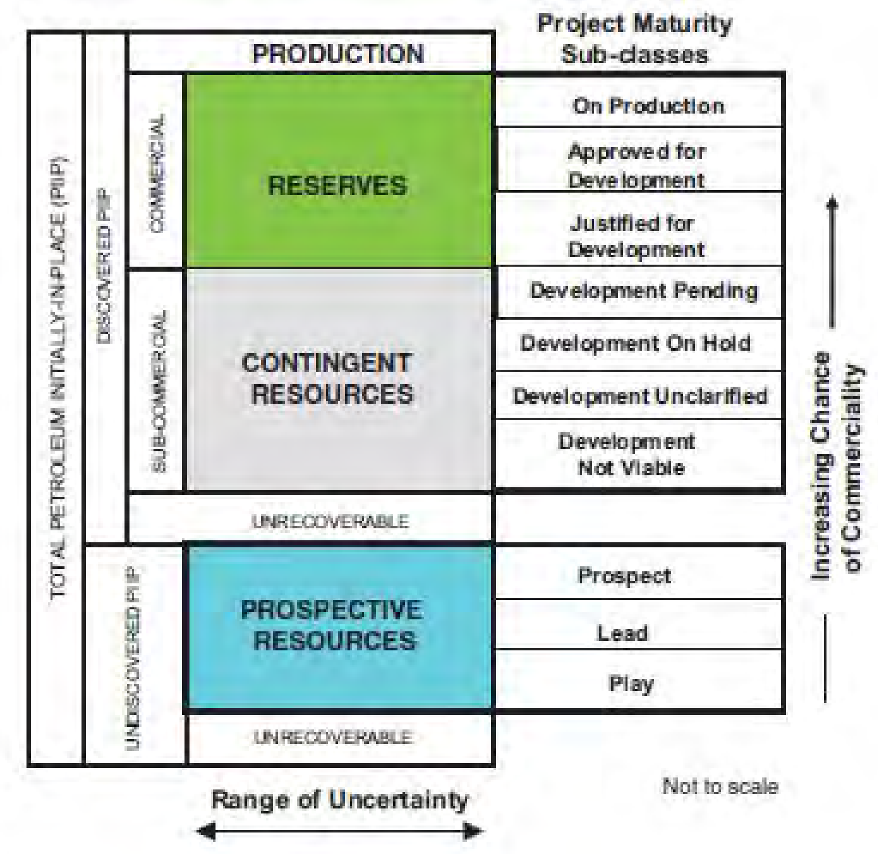

Figure 8-2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System 2018)

8.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

8.1.2 Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

8.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

8.2 Production

Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage (see Section 3.2, Production Measurement).

8.3 Reserves

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

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

8.3.1 Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

8.3.2 Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

8.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

(1) From new wells on undrilled acreage in known accumulations,
(2) From deepening existing wells to a different (but known) reservoir,
(3) From infill wells that will increase recovery
(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

8.3.4 Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

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.

8.3.5 Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P).

In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

8.3.6 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 plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

8.4 Contingent Reources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies.

Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

Projects classified as Contingent Resources have their sub-classes aligned with the entity’s plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources

Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

8.4.1 Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

8.4.2 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 commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.

The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

8.4.3 Contingent Resources: Development Unclarified

A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.

This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

8.4.4 Contingent Resources: Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.

The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

8.5 Prospective Resources

Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources
2U denotes best estimate scenario of Prospective Resources
3U denotes high estimate scenario of Prospective Resources

8.5.1 Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

8.5.2 Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

8.5.3 Play

A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

8.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

9 APPENDIX C: NOMENCLATURE

1-D, 2-D, 3-D	1-, 2-, 3-dimensions
1P	proved
2P	proved + probable
3P	proved + probable + possible
acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute
av.	Average
AVO	Amplitude vs. Off-Set
bbl	barrel
bbl/d	barrels per day
BHP	bottom hole pressure
BHT	bottom hole temperature
boe	barrel of oil equivalent
Bscf	billion standard cubic feet
Bscm	billion standard cubic metres
Btu	British thermal unit
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
DHC	dry hole cost
DHI	direct hydrocarbon indicators
DPT	deeper pool test
DROI	discounted return on investment
DST	drill-stem test
DWT	deadweight tonnage
E & P	exploration & production
E	East
e.g.	for example
EAEG	European Association of Exploration Geophysicists
EOR	enhanced oil recovery
ESP	Electrical Submersible Pump
et al.	and others
EUR	estimated ultimately recoverable
ftMD	feet measured depth
ftss	feet subsea
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
kg	kilogram
km	kilometre
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	metre
M	thousand
m/s	metres per second
Ma	million years (before present)
Mbbl/d	thousands of barrels per day
Mbbl/d	thousands of barrels per day
mbdf	metres below derrick floor
mbsl	metres below sea level
mD	millidarcies
MD	measured depth

mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
MJ	megajoule
ml	millilitres
mls	miles
MM	million
MMbbl	million bbls of oil
MMboe	million bbls of oil equivalent
MMscfd	million standard cubic feet per day
MMscm	million standard cubic metres
mmsl	metres below mean sea level
MMstb	million stock tank barrels
MMt	million tons
mN/m	interfacial tension measured unit
MPa	megapascals
Mscfd	thousand standard cubic feet per day
Mscm	thousand standard cubic metres
msec	millisecond(s)
MSL	mean sea level
mSS	metres subsea
MWh	MegaWatt-hours
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
no.	number (not #)
NPV	net present value
Ø	porosity
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P & A	plugged & abandoned
pbu	pressure build-up
perm.	permeability
PESGB	Petroleum Exploration Society of Great Britain
pH	-log H ion concentration
phi	unit grain size measurement
plc	public limited company
por.	Porosity
poroperm	porosity-permeability
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psia	pounds per square inch absolute
RFT	repeat formation test
ROI	return on investment
ROP	rate of penetration
RT	rotary table
S	South
SCAL	special core analysis
scf	standard cubic feet
scm	standard cubic metre*
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
stb	stock tank barrel
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
Tscf	trillion standard cubic feet
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar
US$MM	Millions of US dollars
UV	ultra-violet
VDR	virtual dataroom
W	West
WD	water depth
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
wt%	percent by weight
XRD	X-ray diffraction (analysis)

PART 9

COMPETENT PERSON'S REPORT FOR THE NIGERIEN ASSETS

CGG Services (UK) Limited

COMPETENT PERSONS REPORT
R1/R2/R4 and R3 Licence Areas, Agadem Basin, Niger

FOR
Savannah Energy PLC
Strand Hanson Limited

CGG Services (UK) Limited Reference No: BP535
April 2020

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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 Energy PLC (Savannah) 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 for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange.

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 Savannah Energy PLC, and on information in previous CGG in-house studies of African rift systems. CGG has relied on Savannah Energy 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 Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warrant as to Savannah Energy PLC's interest in the Properties.

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CGG affirm that from the as-of date of this report, 30th April 2020, 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 Energy 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 for Mining and Oil and Gas Companies published in June 2009 by the London Stock Exchange, for the purpose of inclusion within an AIM Admission document.

Conditions of Usage

The report was compiled during the period October 2019– April 2020 with the effective cut-off date for inclusion of data being 31st December 2019. The effective date for valuation reporting is 31st March 2020. 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 Energy 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 Energy 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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CGG Services (UK) Limited Reference No: BP510				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
01	30 April 2020	RC/PW	AW	Final

Date	**Originator**	**Checked & Approved**
Signed:		

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1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah) and Strand Hanson Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) relating to the R1/R2/R4 and R3 licence areas (the Licence Areas) operated by Savannah in the Agadem Rift Basin (ARB), Niger.

Savannah Petroleum Niger S.A. is the Operator of the R1/R2/R4 and R3 Licence Areas with a 100% ownership in the licences. Savannah has a 95% interest in Savannah Petroleum Niger S.A.

Licence	Operator	Savannah Interest (%)	Status	Licence expiry date	Licence Area
R1/R2/R4*	Savannah Petroleum Niger S.A.	95%	Exploration	2030	11,394 km^2
R3	Savannah Petroleum Niger S.A.	95%	Exploration	2024	2,261 km^2

* R1/R2/R4 PSC is in agreed form with the Ministry of Petroleum and pending transmission to the Ministers Council

Table 1-1 Current Licence Details

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 the China National Petroleum Corporation (CNPC). The Agadem Rift Basin is a part of the wider Central African Rift System (**Figure 1-1**) in which significant oil has been discovered. In the Agadem Rift Basin, three fields are currently on production. Oil from the three fields is currently evacuated by pipeline to the Zinder refinery, located in Niger.

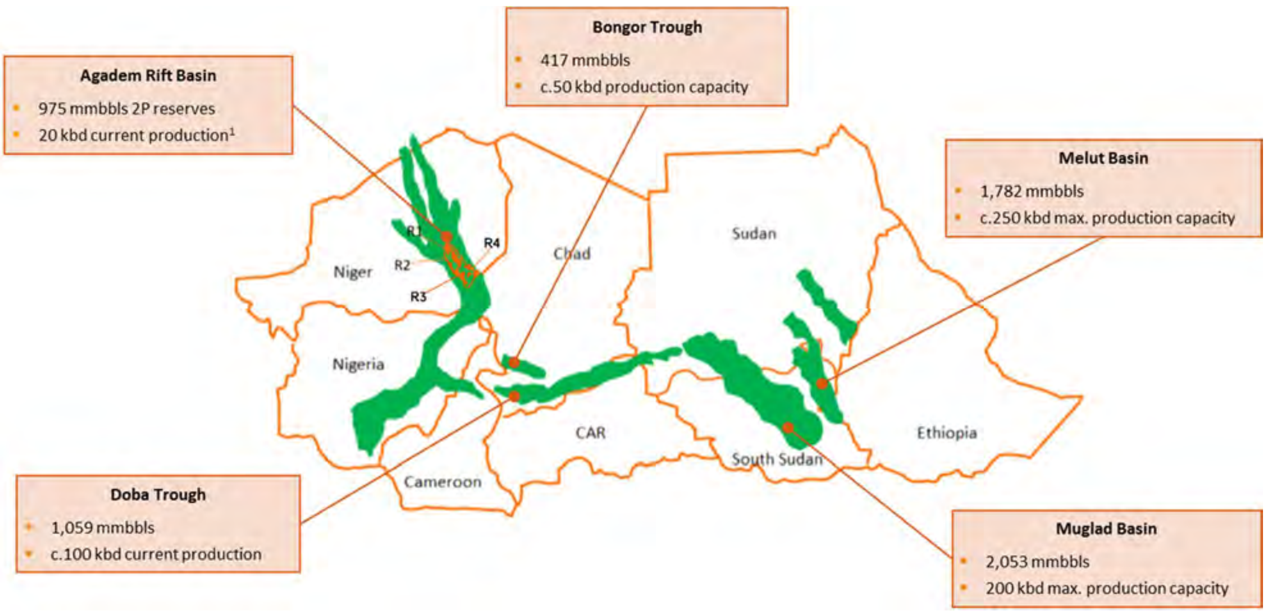


Figure 1-1 The Central African Rift System Discovered Resources (*Source: Savannah, 2017*)

Between 2008 and 2019, CNPC markedly increased the success rate of exploration in the basin, with c. 110 discoveries from 137 wells (80% success rate) establishing 2P Reserves of just under 1 billion barrels. Most of the discoveries made in the Sokor Alternances, demonstrate the low risk profile of this Tertiary play. In addition, several light oil discoveries have been made in the Cretaceous Yogou play directly to the South East of Savannah's R3 Licence area, which highlight the potential of this under-explored play.

Following its entry into Niger in 2014, Savannah has built a comprehensive database composed of existing 2D/3D seismic and well data, which have been interpreted to both build and de-risk the current exploration portfolio. To complement the existing dataset, Savannah acquired a Full Tensor Gravity Gradiometry (FTG) and High-Resolution Airborne Magnetic (HRAM) surveys in 2014/2015 over the full Agadem rift basin. Back in 2016, Savannah identified the R3 East area as low risk exploration region (93% success rate in surrounding wells), believed to be an extension of the light oil play successfully drilled by CNPC. To derisk this area, Savannah completed the acquisition and processing of an 806km^2 3D seismic survey in 2016/2017. Interpretation of the survey confirmed a number of previously identified Tertiary structures in the Sokor Alternances, and five of these were subsequently drilled in a back-to-back campaign in 2018. These discoveries (namely Bushiya, Amdigh, Kunama, Eridal and Zomo) confirm the presence of light sweet crude and good quality reservoir analogue to the currently producing fields. Amdigh's STOIIP estimates show the discovery to be one of the 10th largest in the basin. It should be noted that the average size of the Savannah discoveries, c. STOIIP of 30MMstb, is in line with the basin exploration statistics.

Savannah has built an exploration portfolio containing a total of 146 leads and prospects to date (**Figure 1-2**) with a total Unrisked Best Estimate of c. 6.7 bn bbls Oil Initially In Place. In addition to the prospect and lead inventory within proven plays, Savannah has also identified several new, potentially significant exploration plays which offer genuine high risk, high reward upside.

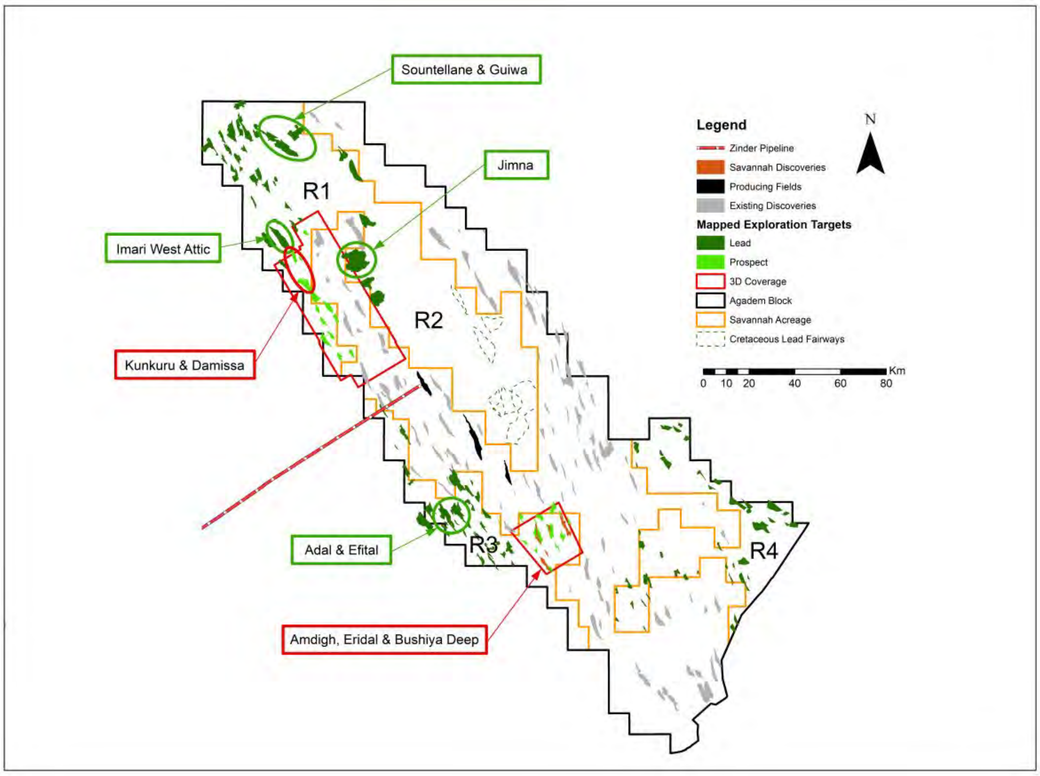


Figure 1-2 Savannah's Prospects and Leads Portfolio (*Source: Savannah, 2019*)

CGG has estimated STOIIP and Resource volumes for the five discoveries made on the R3 licence area in 2018 and a subset of eleven prospects and leads from Savannah's extensive exploration portfolio comprising of up to 146 prospects and leads, and has also provided estimates of the yet-to-find resources in the Licence Areas. The eleven prospects and leads have been identified as potential candidates for the next exploration drilling campaigns across the Licence Areas.

In addition, CGG has calculated expected recovery factors, and verified indicative economics for the early development scheme proposed by Savannah. CGG has conducted a technical review the five discoveries that have been drilled in 2018, namely: Bushiya, Amdigh, Eridal, Kunama and Zomo. **Figure 1-3** shows a map of the R3 East area showing the five oil discoveries which oil sampling confirm oils to be medium to light (24º to 33º API) and "sweet" (<0.5 wt. % Sulphur). Reservoir quality varies from medium (E1 and E2) to high (E3 to E5) and is in line with the neighbouring CNPC producing fields and discoveries.

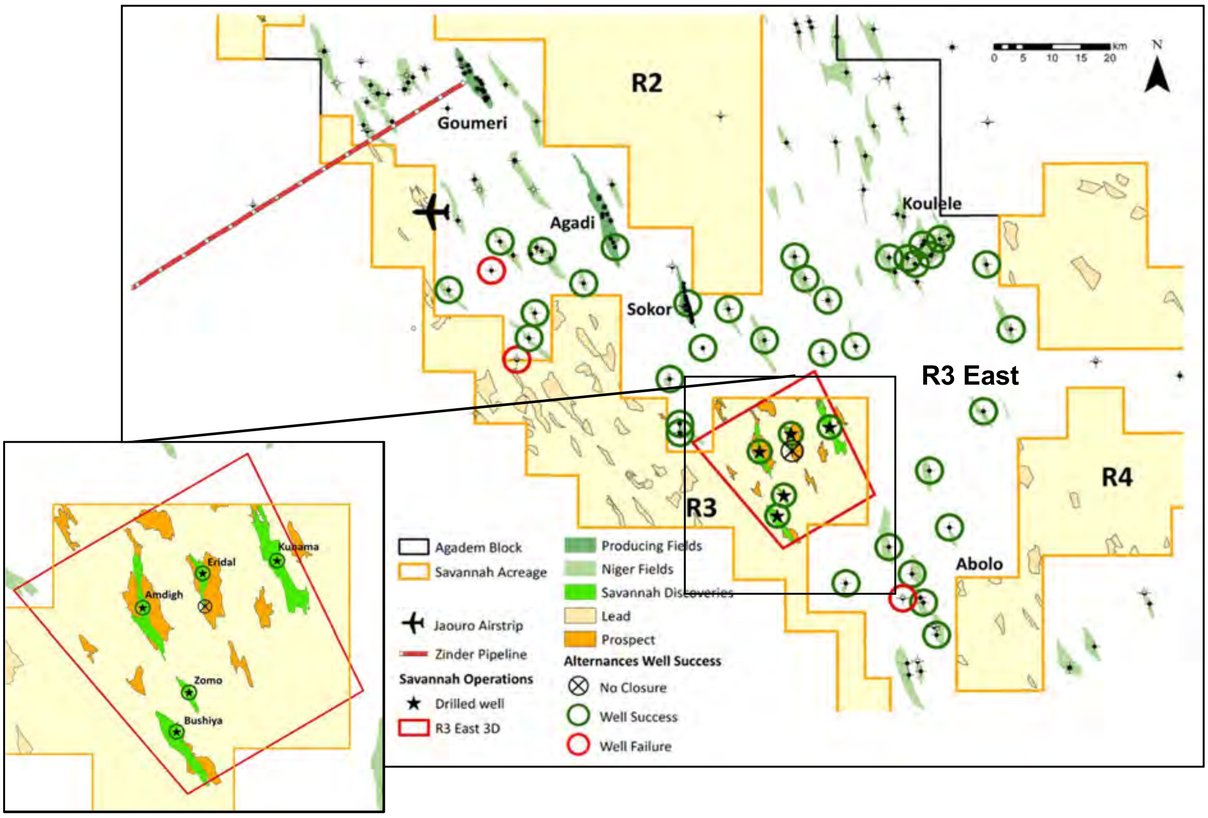


Figure 1-3 Map showing the location of the five 2018's discoveries (*Source: Savannah, 2019*)

CGG has used expected recovery factors for the discoveries 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 23%, 28% and 33% to the STOIIP figures to calculate recoverable volumes for the low, best and high Contingent Resources cases, respectively.

Contingent and Prospective Resources have been calculated by CGG in accordance with the Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) and the AIM Note for Oil and Gas Companies (2009) for the discoveries and identified prospects and leads, and are summarised in the tables below.

	Contingent Resources (MMstb)							
	Gross			Net attributable				
Discovery	1C	**2C**	3C	1C	**2C**	3C	**Risk factor**	**Operator**
Amdigh	*7.2*	18.4	*83.9*	*6.8*	17.5	*79.7*	low	Savannah
Eridal	*4.3*	6.2	*8.5*	*4.0*	5.9	*8.1*	low	Savannah
Bushiya	*3.3*	6.2	*12.9*	*3.2*	5.9	*12.3*	low	Savannah
Kunama	*1.8*	4.2	*9.3*	*1.8*	4.0	*8.8*	low	Savannah
Zomo*		0.2			0.2		medium	Savannah
Total**	***16.7***	**35.0**	***114.6***	***15.8***	**33.3**	***109.1***		

Notes

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
   Risk factor: low = > 75%, medium = 25% - 75%, high = <25%
5. *Full definitions of the Contingent Resource categories can be found in Appendix B*

** Indicative Resources pending PSDM evaluation,*
*** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding*

6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and government share of profit*

Table 1-2 Contingent Resources

Similarly, to the Contingent Resources, CGG has applied recovery factors of 23%, 28% and 33% to the STOIIP figures to calculate recoverable volumes for the low, best and high Prospective Resource cases, respectively. Individual stratigraphic reservoir volumes have been summed probabilistically, in order to calculate an overall prospect or lead resource total. Most leads and prospects are composed of stacked targets in the Upper Sokor, Sokor Alternances and Yogou formations which will be accessible from a single well trajectory.

Licence	Prospect/Lead	Unrisked Prospective Resources (MMstb)						Risk factor
		Gross			Net			
		Low Estimate	**Best Estimate**	High Estimate	Low Estimate	**Best Estimate**	High Estimate	
R3	**Bushiya Deep**	*1.8*	7.6	*22.5*	*1.7*	7.3	*21.3*	*medium*
R3	**Amdigh Deep**	*2.6*	10.9	*32.7*	*2.4*	10.4	*31.0*	*medium*
R3	**Eridal Deep**	*1.7*	6.9	*20.0*	*1.6*	6.6	*19.0*	*medium*
R3	**Adal**	*3.2*	20.6	*72.6*	*3.0*	19.6	*69.0*	*medium*
R3	**Efital**	*8.7*	44.0	*130.0*	*8.3*	41.8	*123.5*	*medium*
R1/R2/R4	**Sountellane**	*9.4*	35.8	*108.2*	*8.9*	34.0	*102.8*	*medium*
R1/R2/R4	**Damissa**	*13.2*	66.9	*188.1*	*12.5*	63.6	*178.7*	low
R1/R2/R4	**Imari W Attic**	*8.8*	45.4	*149.5*	*8.3*	43.1	*142.0*	high
R1/R2/R4	**Guiwa**	*6.5*	30.0	*89.8*	*6.2*	28.5	*85.3*	high
R1/R2/R4	**Kunkuru**	*1.9*	10.4	*31.3*	*1.8*	9.9	*29.8*	low
R1/R2/R4	**Jimna**	*17.2*	81.5	*254.8*	*16.3*	77.4	*242.0*	high
Total*		***74.9***	**360.1**	***1099.4***	***71.2***	**342.1**	***1044.4***	

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*
   Risk factor: low = > 75%, medium = 25% - 75%, high = <25%
6. *Net: the portion of the gross resources attributable to Savannah before royalties, taxes and government share of profit*
7. *Savannah is the Operator of the assets*

** Arithmetic sum, Total may not add exactly due to rounding*

Table 1-3 Selected Prospective Resources (for a subset of 11 out of 146 prospects/leads portfolio)

CGG has reviewed Savannah's in-house methodology for assessing gross mean Unrisked STOIIP for the selected eleven 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 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/R4 and R3 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.

	Gross Prospective Resources – "yet to find" (MMstb)					
	Unrisked			Risked		
Licence	**Low Estimate**	**Best Estimate**	**High Estimate**	**Low Estimate**	**Best Estimate**	**High Estimate**
R1/R2/R4	2156	5675	8456	851	2239	3337
R3	405	1126	1531	149	456	531
Total	**2561**	**6801**	**9987**	**1000**	**2695**	**3868**

* Arithmetic sum

Table 1-4 Estimate of gross Unrisked and Risked "yet to find" Resources

Since the drilling of the five discoveries, Savannah has developed an Early Production Scheme (EPS) which includes an early trucking phase followed by evacuation of crude via a new 90km pipeline (**Figure 1-4**). The proposed development plan utilises a leased Early Production Facility (EPF), which will permit early revenues before a permanent Central Processing Facility (CPF) is installed and commissioned. The recent development in the construction of the Niger to Benin export route is a milestone, that provides Savannah with an alternative route for its crude but more importantly enable the full potential of the Licence areas to be unlocked.

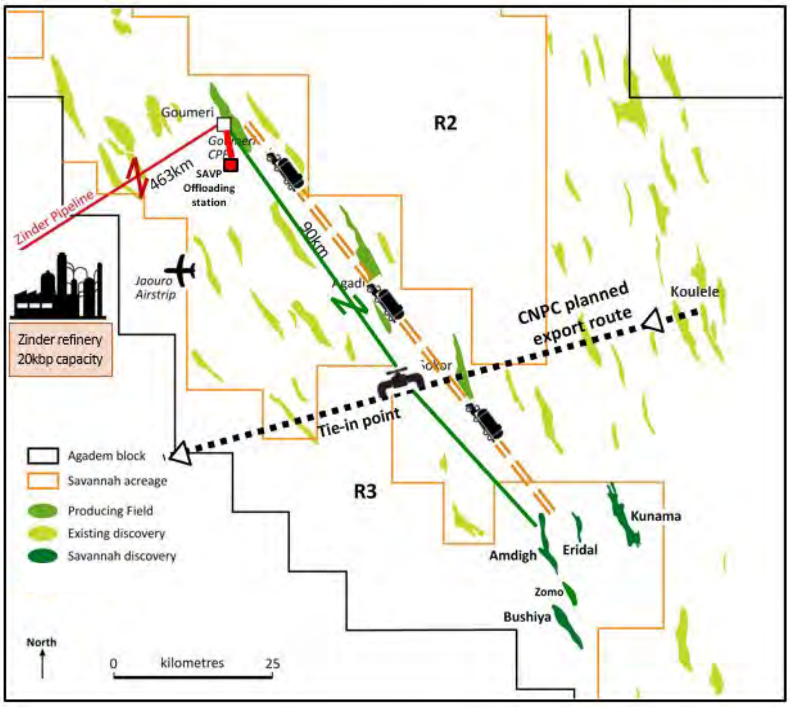


Figure 1-4 Proposed Early Production Scheme Development ***(Source: Savannah, 2019)***

The proposed Early Production Scheme is summarised below.

Phase I:- Trucking

- Expected to deliver a plateau of up to 1,500 bopd from the Amdigh-1 and Eridal-1 wells, following well testing.
- An Early Production Facility procured on a rental basis initially;
- Oil to be trucked c.120km to the Goumeri Export Station, then piped to the Zinder refinery (using the existing 463km Agadem to Zinder pipeline).

Phase II:- Pipeline Crude Evacuation

- Central Processing Facility (CPF) expected to be constructed at Amdigh, planned to be linked to a gathering system to enable proximal fields (e.g. Bushiya, Kunama, Eridal) to be tied into the CPF;
- Planned construction of a c. 90km pipeline between the CPF and the Goumeri Export Station;
- Production expected to ramp up to 5,000 bopd, one year after first oil and following completion of pipeline construction.

The results of the economic analysis are presented in the table below and are based on a fixed domestic oil price of US$42/bbl (at the refinery gate), followed by US$55/bbl- US$60/bbl- US$62.4bbl- Brent oil price between 2022 to 2024 (escalating at 2% per annum from 2025) when the CNPC Niger-Benin export pipeline has come online given the principal of export parity between the domestic price and the price that can be realised for the oil when exported.

Case	2C
NPV0 (US$MM)	358.9
NPV10 (US$MM)	132.8
NPV10/bbl (US$)	5.8

Notes

1. *NPVs are based on net production of 23 MMstb post economic cut-off and 15% government back-in right*

Table 1-5 Indicative Economics (net to Savannah) for Discoveries

NPV sensitivities relating to oil prices and costs have also been run on the base case, and are presented below.

The break-even domestic oil price which would enable Savannah to generate a 10% IRR on the development would be approximately US$26/bbl, assuming costs would be reduced at this oil price level by at least 20% from those prevailing at a long-term US$60/bbl assumption, which CGG has assessed as reasonable.

As a sensitivity, the economics of tying-in a 20 MMstb prospect to the Amdigh facilities have also been evaluated. On the basis of minimal modifications to the facilities, this analysis yielded an incremental unrisked NPV10 of approximately $100mn net to Savannah.

Case	2C
Base case	132.8
+30% factor on costs	74.9
-15% factor on costs	158.2
Oil price +25%	200.9
Oil price -25%	49.0
Production volume + 25%	192.9

Table 1-6 Sensitivities for Indicative Economics (NPV10, US$MM)

2 INTRODUCTION

2.1 Overview

The R1/R2/R4 and R3 License Areas are located in the Agadem Rift Basin (ARB) 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 is provided in **Figure 2-1**.

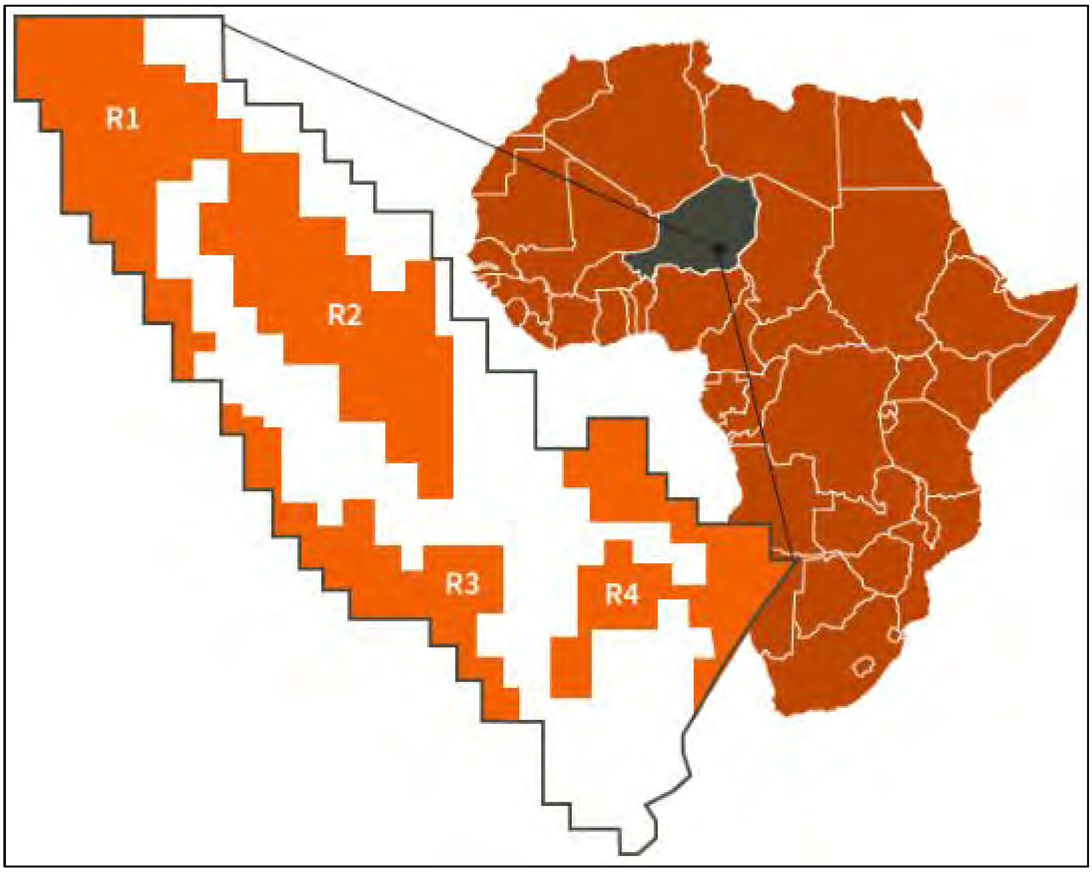


Figure 2-1 Map showing location of the assets (*Source: Savannah, 2017*)

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 (**Figure 2-2**). 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. The topography in the Licence Areas is relatively flat and although it is a desert there are no significant mobile sand dunes. The area is c.200km 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.

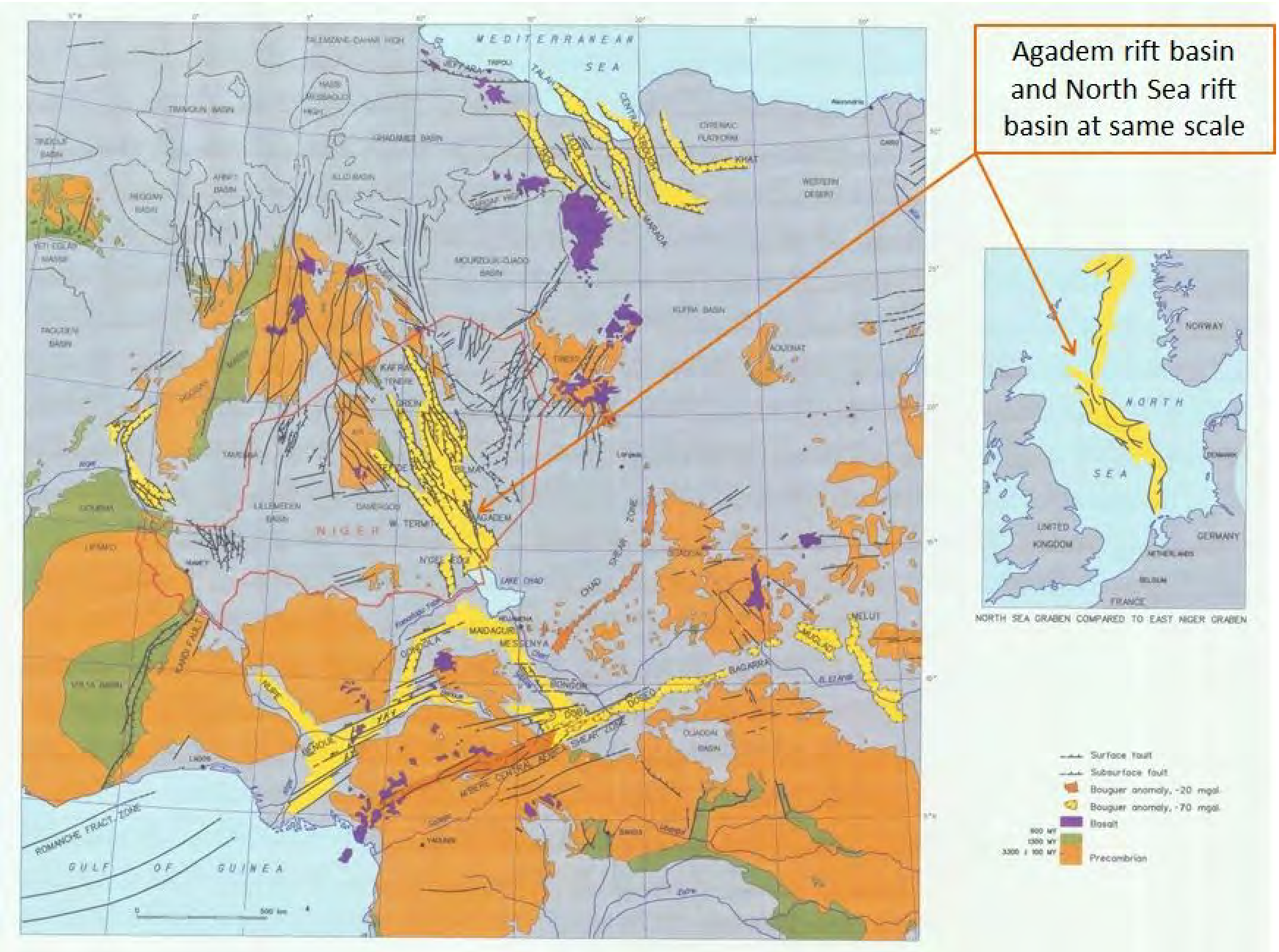


Figure 2-2 Map comparing magnitudes of the basins of Niger and the North Sea

(Source: Niger Ministry of Energy & Petroleum, and in-house Robertson studies, 2017)

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 S.A. is the Operator of the R1/R2/R4 and R3 Licence Areas with a 100% ownership in the licences. Savannah has a 95% interest in Savannah Petroleum Niger S.A.

The basin shows classic rift geometries (**Figure 2-3**) and in the Savannah Licences contains multiple stacked hydrocarbon plays **(Figure 2-4)**.

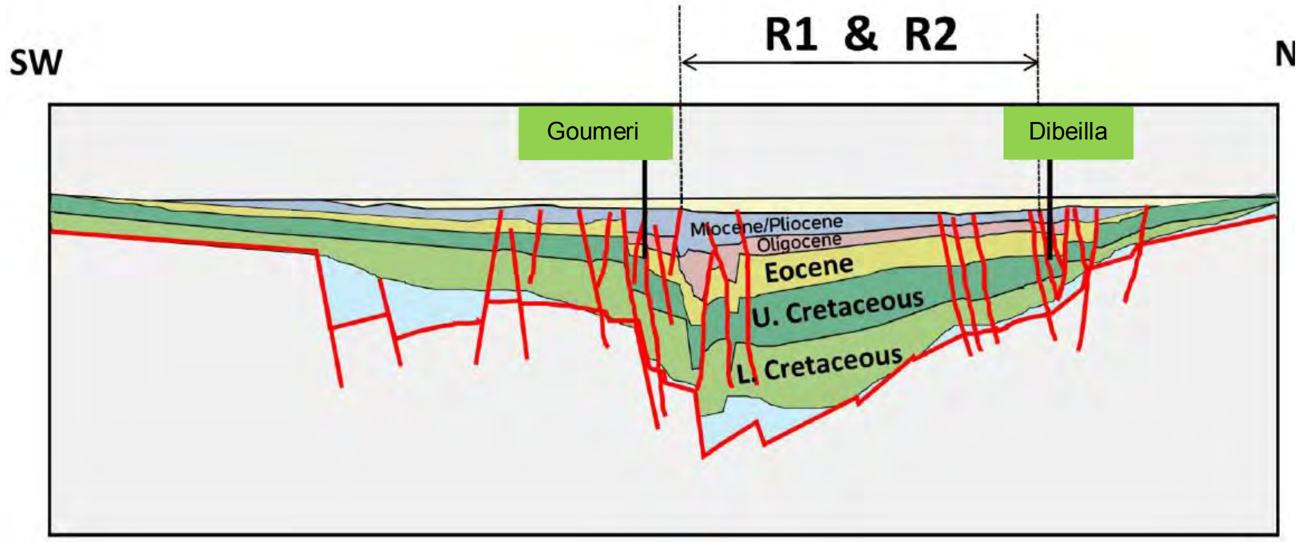


Figure 2-3 Schematic South-West to North-East Cross-Section through the Agadem Rift Basin, Niger

(Source: Niger Ministry of Energy & Petroleum and Savannah, 2017)

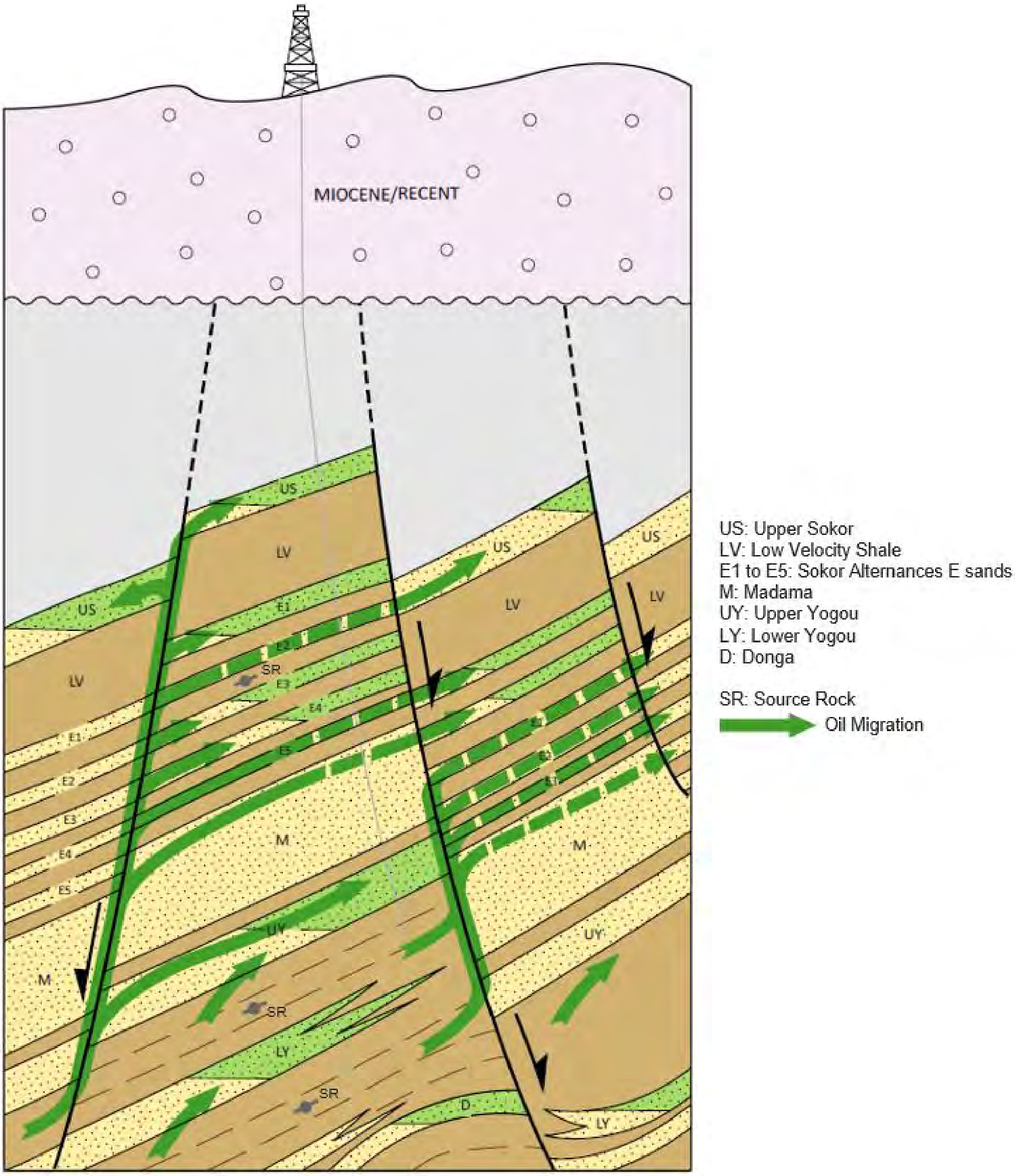


Figure 2-4 Schematic South-West to North-East cartoon cross-section to illustrate the main trapping and charging mechanisms in the Agadem Rift Basin *(Source: Savannah, 2019)*

2.2 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
- Work plans and budgets

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.

2.3 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 30 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.

Patricio Marshall

Patricio graduated with a degree in geology and has over 30 years' experience in the upstream oil and gas industry. He is Principal Geoscientist in the Geoconsulting Group at CGG. He worked 10 years with Pluspetrol in Argentina, Bolivia, Peru, Algeria and Tunisia doing exploration projects, 5 years with Golden Oil Corp. doing exploration and development projects in Argentina, Peru and Colombia, as well as asset evaluations in

Argentina, and 10 years as independent consultant working in exploration projects, regional studies, unconventionals, and asset evaluation projects. Member of the AAPG and SEG.

Toni Uwaga

Toni Uwaga has an MSc from Heriot Watt University, Edinburgh, in Petroleum Engineering. He has 22 years' industry experience. Over the years he has worked on oil and gas projects spanning the North Sea, East Irish sea, Gulf of Guinea, Middle East, India, Malaysia, North America and the Caribbean Sea. He functioned as Reserves Coordinator for Shell Petroleum Development Company, Nigeria. He has participated as Lead Reservoir Engineer in several CPRs across the various regions he has worked. He is a member of the Geological Society of Trinidad and Tobago (GSTT) and the Society of Petroleum Engineers (SPE). He has several technical papers, published by GSTT and SPE.

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.

2.4 Evaluation methodology

In evaluating the Resources associated with the discovered fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation.

As an initial stage in the evaluation process, Savannah demonstrated the seismic interpretations during a visit by CGG to their office in October 2019. During the other visits, geological, engineering and commercial issues were also discussed face to face with Savannah's technical staff.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Resources, projections of production profiles and estimates of capital and operating costs provided by Savannah. The Resources have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

In addition, CGG has estimated resource volumes for eleven indicative prospects and leads selected by Savannah from its exploration portfolio. These prospects and leads are currently under consideration as potential further drilling candidates in Savannah's next exploration drilling campaign. CGG has also provided estimates of the yet-to-find resources in the licences.

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.

The evaluation has been performed in accordance with the:

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)

- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

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 Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

3 RESOURCE DESCRIPTION

3.1 Tectonostratigraphy

The 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 with a total thickness of more than 5km 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, and 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 this was accompanied by uplift of the basin margins. 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.

3.2 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 the 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 biostratigraphy 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.

3.3 Petroleum geology of stratigraphic units

3.3.1 Upper Sokor Formation

Savannah currently carries oil volumes at this level in six 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 the 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 1600m. 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.

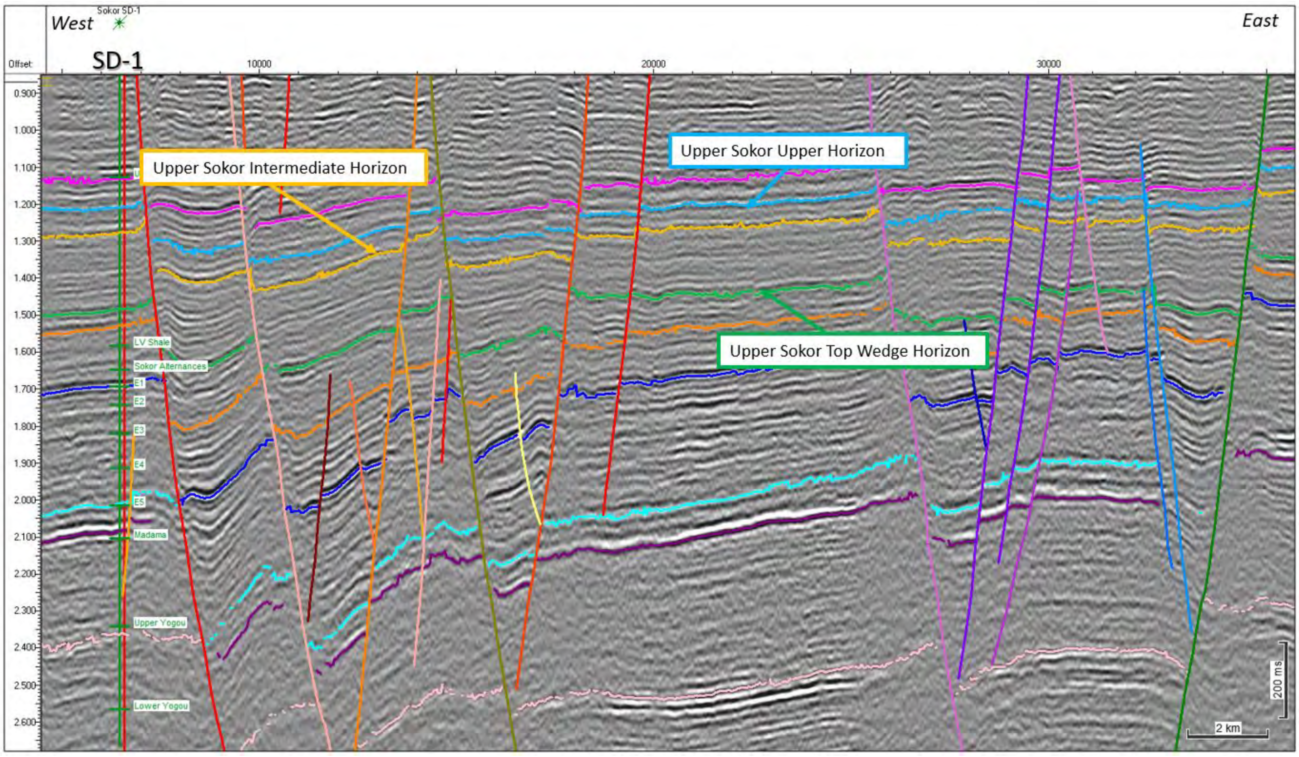


Figure 3-1 W-E 3D seismic profile through Sokor SD-1 well, in the R3 East 3D (*Source: Niger CPR 2017*). The Upper Sokor contains variable amplitudes within a subtle sedimentary wedge above the LV Shale (green to orange markers)

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

.

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.

3.3.2 Sokor Alternances Formation

Savannah currently carries oil volumes at this level in six 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 three or four charged reservoirs in the Eocene fields.

3.3.3 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.

3.3.4 Yogou Formation

Savannah currently carries oil volumes at this level in ten 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.

3.3.5 Lower Yogou and Donga Formation

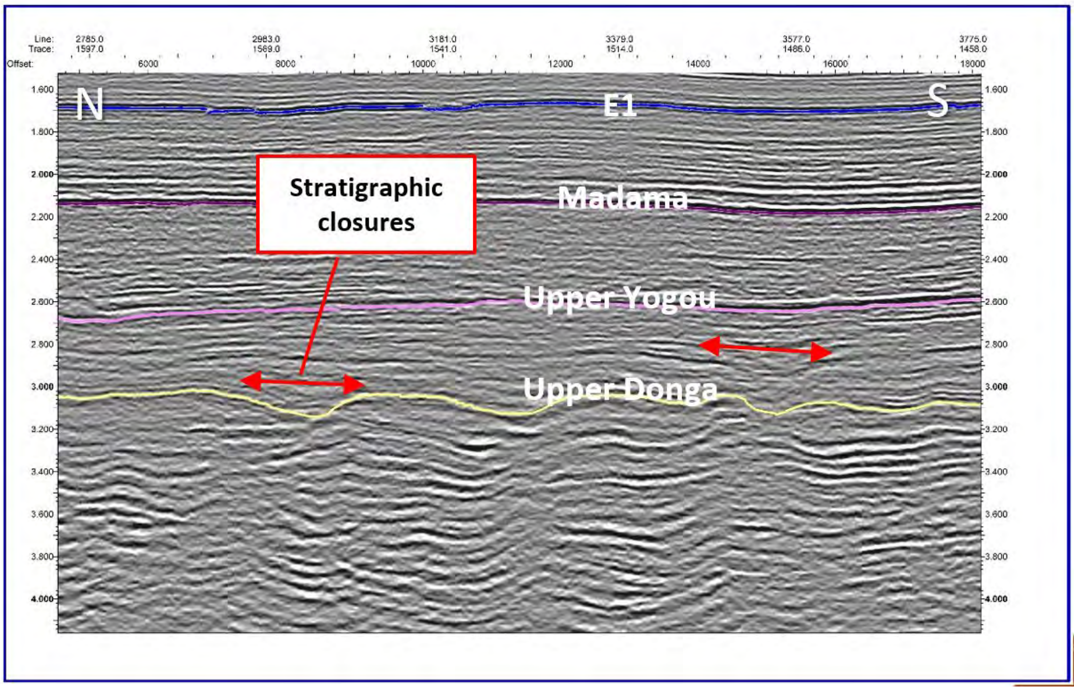
Cretaceous folding and Cenozoic faulting together form an additional set of trapping geometries beneath Savannah's acreage at Lower Yogou and Donga levels. **Figure 3-2** illustrates these features. In some parts of Savannah's acreage these intervals are found at depths that are relatively easily drillable.

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 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 4.3**).



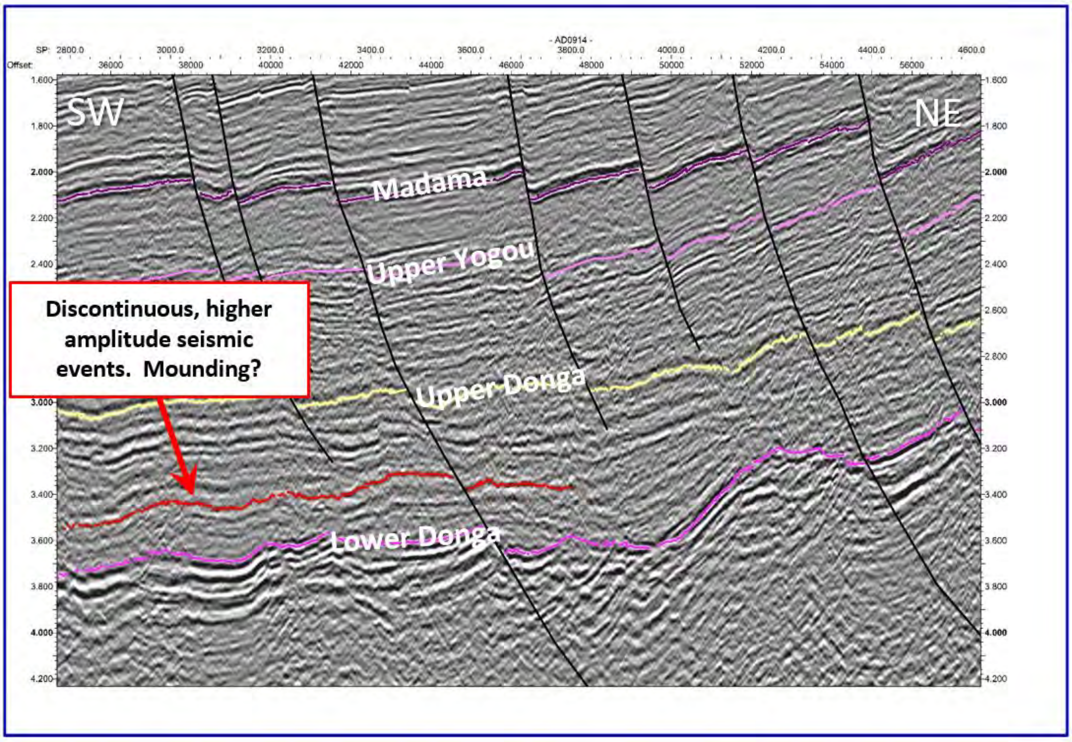


Figure 3-2 Structures at the Lower Yogou and Donga levels – Top: Arbitrary line within the R3 East 3D seismic survey Bottom: 2D seismic line within the R4 area *(Source: Savannah, 2019)*

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.

3.4 Discoveries

In 2018, Savannah selected five prospects to be drilled from their portfolio in the R3 East portion of the R3 License area. Of the five wells drilled (i.e. Amdigh-1, Eridal-1, Bushiya-1, Kunama-1 and Zomo-1), all found hydrocarbons within the Sokor Alternances (Eocene age) and can be considered discoveries giving a success rate of 100%.

All the structures are within the R3 East 3D seismic survey acquired by Savannah in 2016/2017 and also lie within the NW-SE regional oil discovery trend observed in the neighboring CNPC licence (**Figure 3-3**).

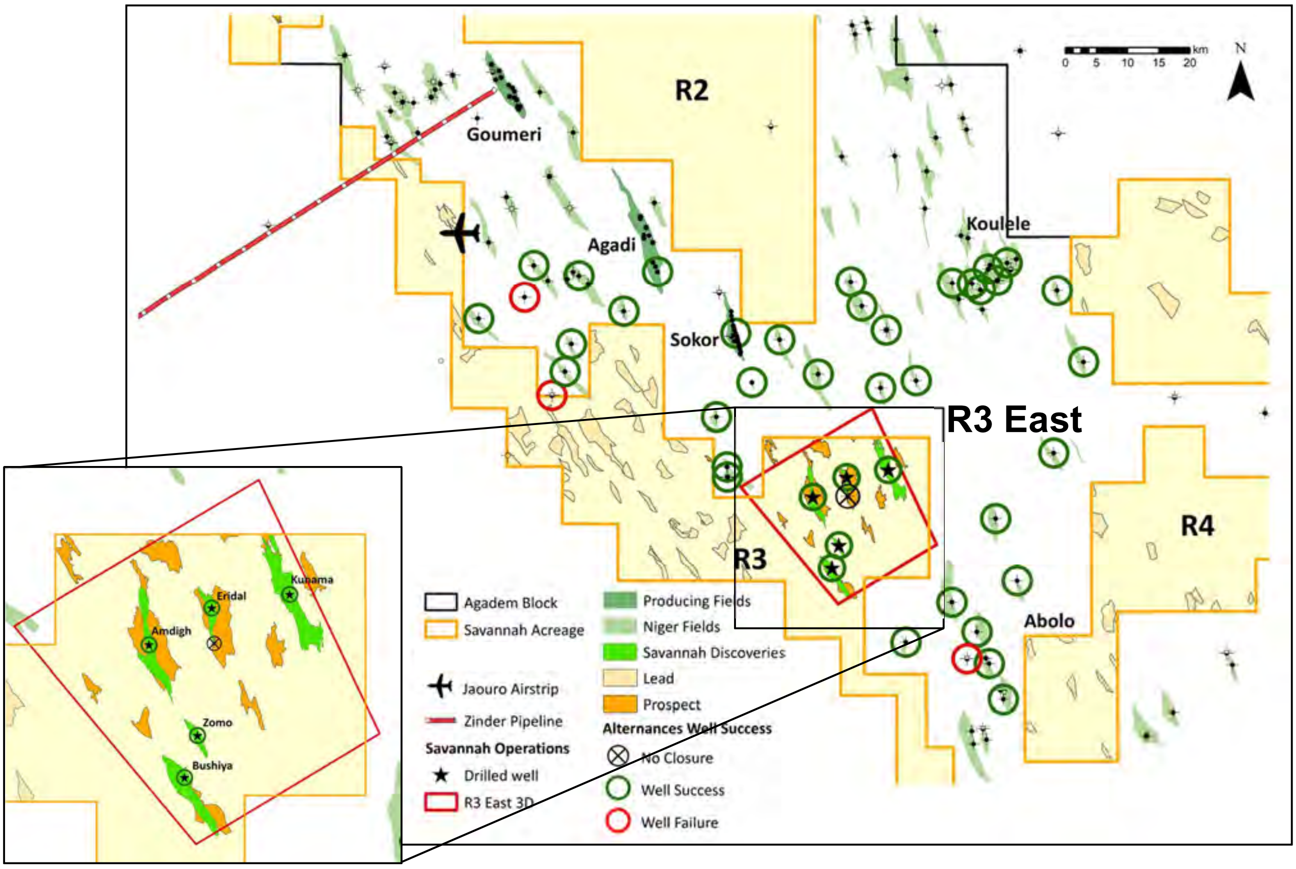


Figure 3-3 Location map of discoveries within the R3 East 3D survey *(red polygon, source: Savannah, 2019)*

CGG had access to Savannah's seismic project interpretation and performed a detailed QC of the interpreted closure areas (polygons) for the discoveries, confirming that the numbers of the estimated areas were reliable. All the well information mentioned below was provided by Savannah, and no further interpretation or petrophysical analyses were performed by CGG. Graphs and all the petrophysical parameters used in the Savannah volumetric calculations are extracted from documents given to CGG (R3 East Feasibility Study Report, Corporate and Technical presentations). It should be noted that the seismic interpretation used to generate depth maps and volumetric estimates is based on the Pre-Stack Time Migration (PSTM) R3 East 3D dataset processed in 2017. Savannah has now completed a Pre-Stack Depth Migration (PSDM) re-processing of the R3 East 3D seismic survey and is currently finalising its interpretation.

3.4.1 Amdigh discovery

Located in the central-north of the R3 East 3D survey, the trap consists of a tilted fault block, and encountered oil columns (c. 20m total net pay) in sequences E1, E2 and E3 of the Sokor Alternances. The well was drilled down to a TD of 2469 m MDBRT (2049 m TVDSS) after penetrating 55 m into the Madama Fm (**Figure 3-4**). The presence of oil in the E1 and E2 was confirmed by recovery of oil samples and by the interpretation of Reservoir Formation Tester (RFT) pressure data. The analysis of the E1 sample show an oil API gravity of 27.5° which is consistent with offset wells along trend and the depth/API trend observed across the basin. Based on the RFT interpretation, the E3 interval was considered as pay.

Within the same discovery, Savannah identified different segments for the E1, E2 and E3 (**Figure 3-5**), which were taken into consideration. The discovery well is drilled in segments 1&2, and it is considered that segment 3 is very likely to be in pressure communication due to the low displacement on the bounding fault especially towards the top of the structure. It is less clear if segments 4, 5 and 6 also form part of the discovery and hence those segments have been removed from the low and most likely cases and only considered in the high case (**Section 4**).

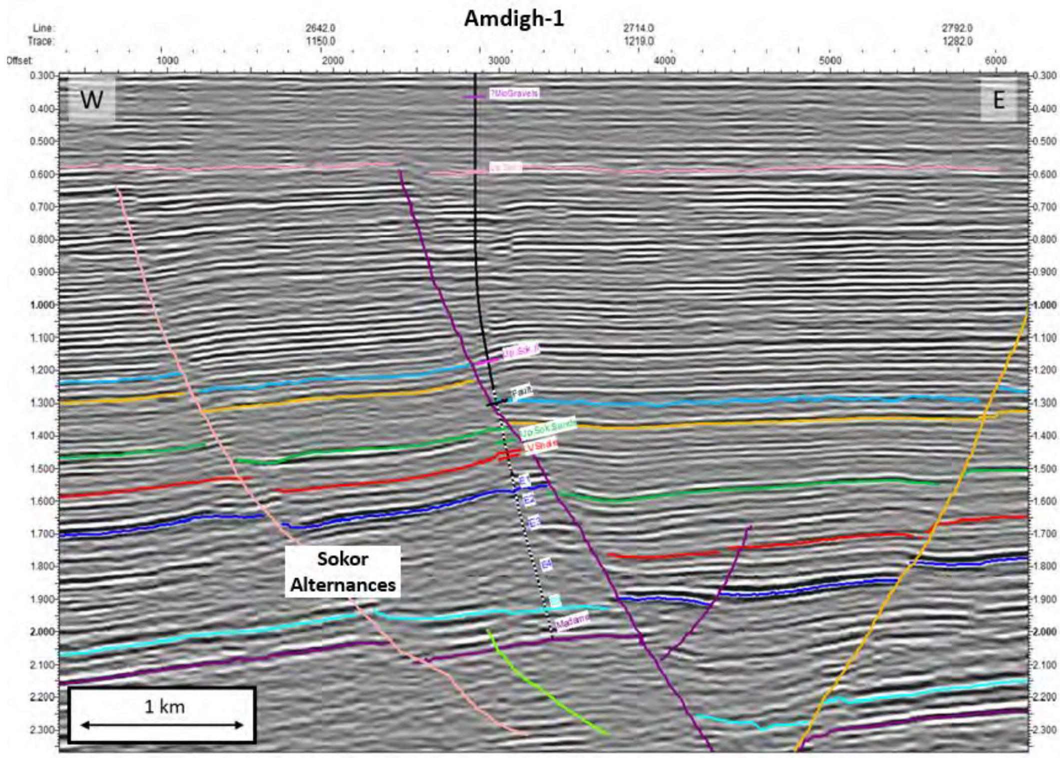


Figure 3-4 PSTM Seismic Section through the Amdigh-1 discovery well *(Source: Savannah, 2019)*

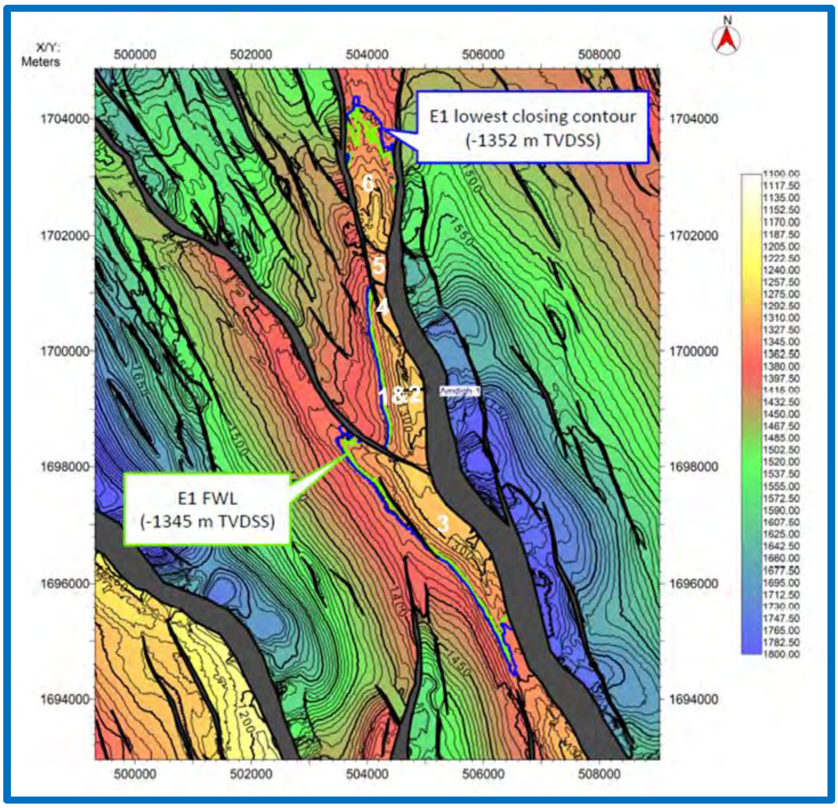


Figure 3-5 Amdigh E1 structural depth map (based on PSTM dataset) and the six segments *(Source: Savannah, 2019)*

3.4.2 Bushiya discovery

This discovery is situated in the southern part of the R3 East 3D survey, and the trap is a tilted fault block type. Bushiya-1 was drilled down to a TD of 2200 m MDBRT (1811 m TVDSS) after penetrating 109 m into the Madama Fm (**Figure 3-6** and **Figure 3-7**). Two oil columns were encountered in the E1 and E3 intervals with an estimated c. 10 m total net pay. The E1 column was proven by recovery via RFT of a 24.2°API oil sample, inline with the Amdigh-1 oil analysis from the same interval. The E3 oil column was interpreted from the RFT pressure data.

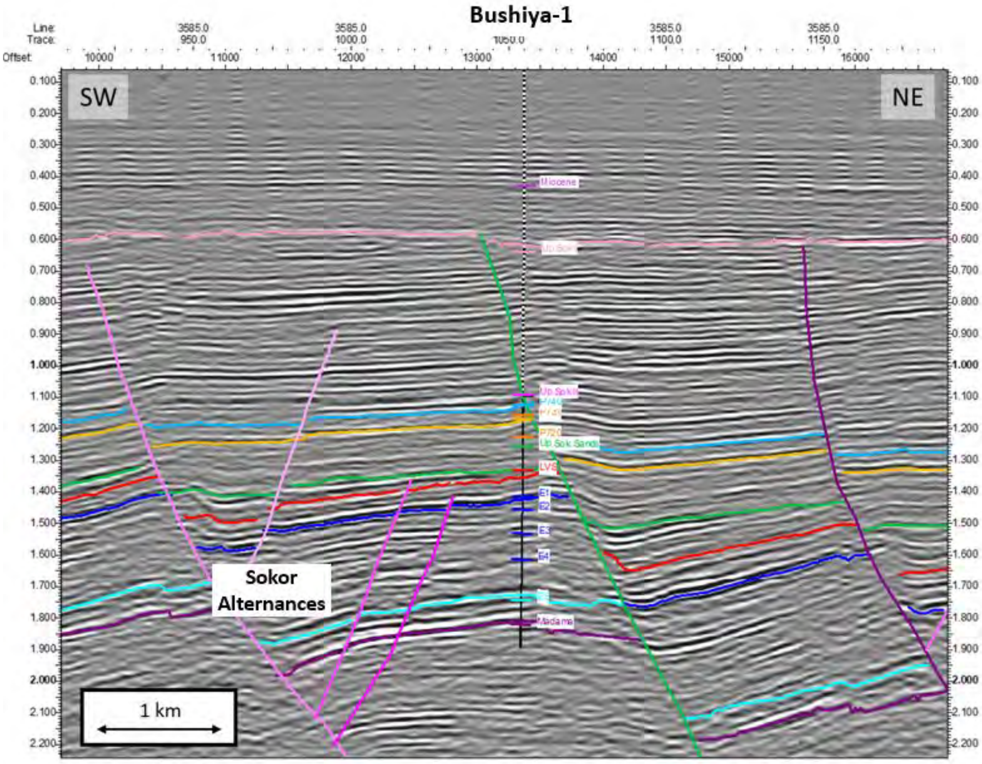


Figure 3-6 PSTM Seismic Section through Bushiya-1 discovery well *(Source: Savannah, 2019)*

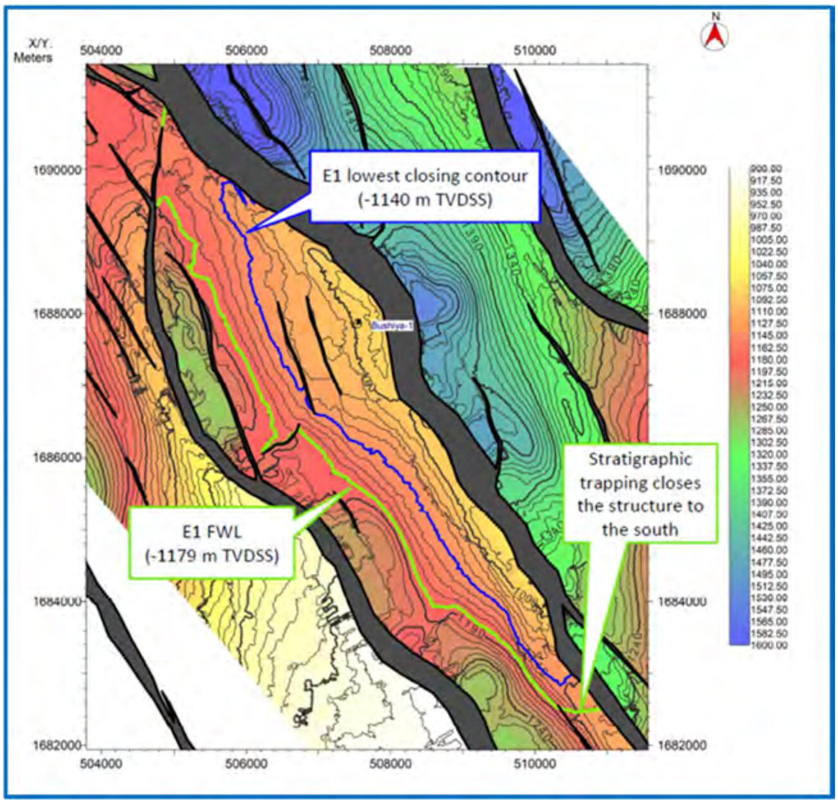


Figure 3-7 Bushiya E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

3.4.3 Kunama discovery

The Kunama-1 discovery is located in a slightly tilted block and was drilled down to a TD of 2460 m MDBRT (2118 m TVDSS) after penetrating 100 m into the Madama Fm (**Figure 3-8** and **Figure 3-9**). An oil column was proven in the E1 interval in the Sokor Alternances by recovery of 28°API oil in an RFT sample. A second oil sample of 24.6°API gravity was recovered by RFT in the E5 interval. A total net pay of c. 9 m was interpreted from logs. As for the oil recovered in Amdigh-1 and Bushiya-1, the oils in both E1 and E5 intervals are light. RFT pressure interpretation at Kunama was used to define a range of contact for subsequent STOIIP estimation.

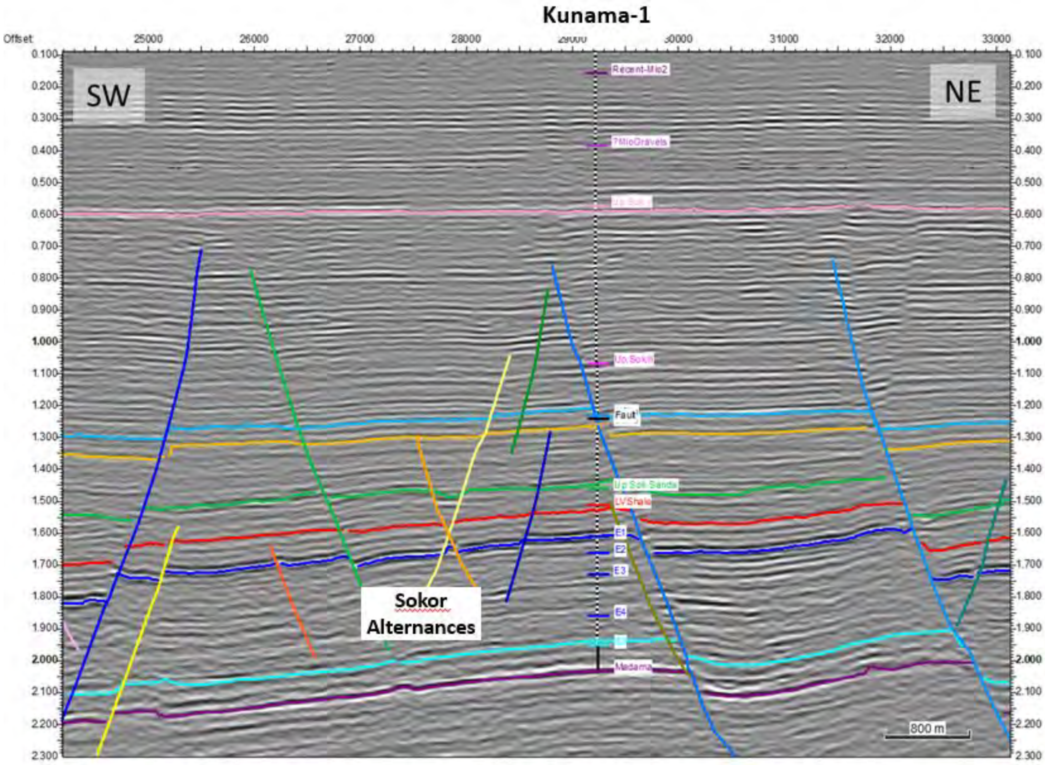


Figure 3-8 PSTM Seismic Section through discovery well Kunama-1 ***(Source: Savannah, 2019)***

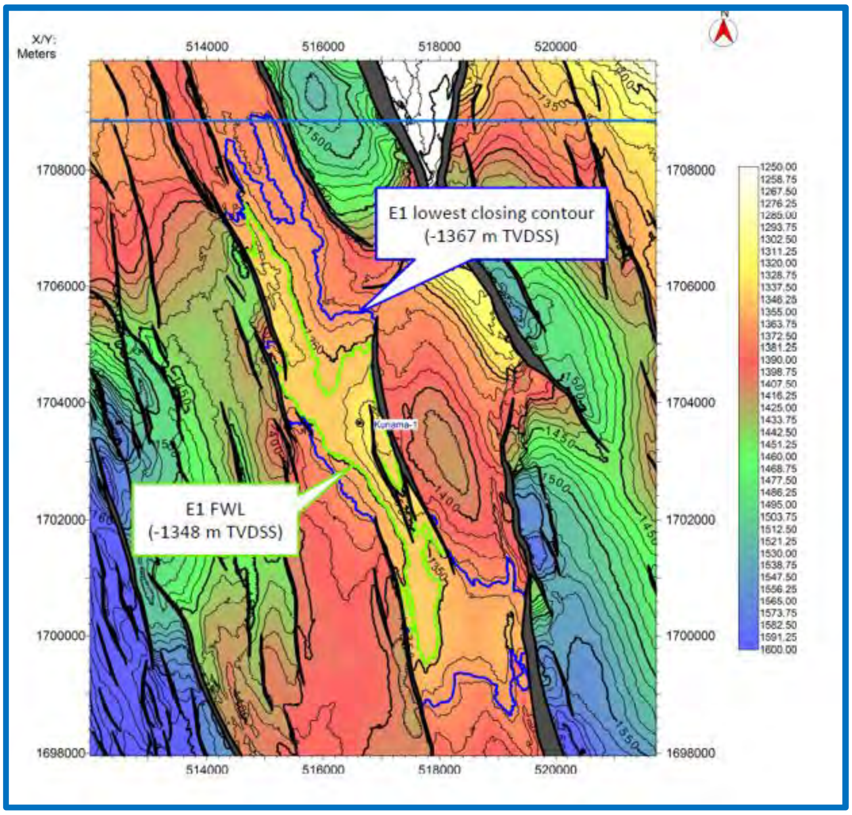


Figure 3-9 Kunama E1 structural depth map ***(based on PSTM dataset, source: Savannah, 2019)***

3.4.4 Eridal discovery

This is a tilted fault block, located to the east of Amdigh. Eridal-1 was drilled down to a TD of 2542 m MDBRT (2203 m TVDSS) after penetrating 97 m into the Madama Fm (**Figure 3-10** and **Figure 3-11**). The well encountered oil in the Sokor Alternances E1 section (c.10 m net pay), as proven by RFT gradient analysis, a RFT oil sample (33 °API) and petrophysical analysis. Interpretation of the RFT pressure data show that the E1 sand contains an oil column which is continuous within the pay section.

Along the same structural trend but to the south the Ourami-1 well (oil shows present in the Alternances) penetrated these levels but was likely drilled out of closure.

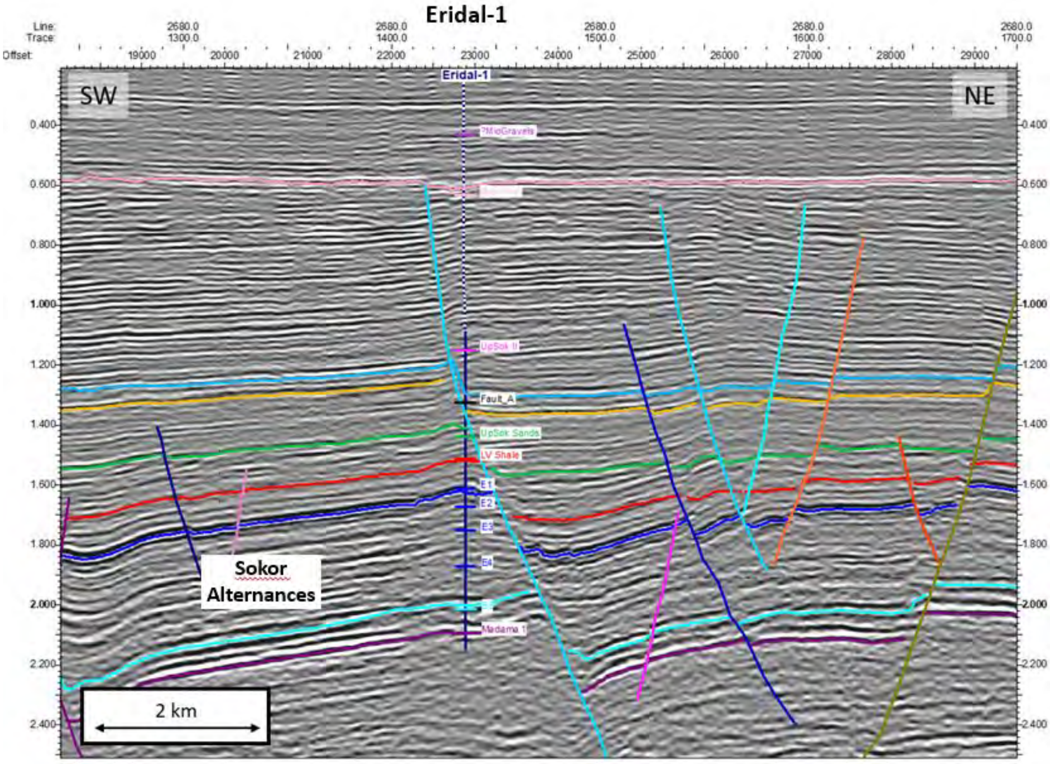


Figure 3-10 PSTM Seismic Section through Eridal-1 discovery well *(Source: Savannah, 2019)*

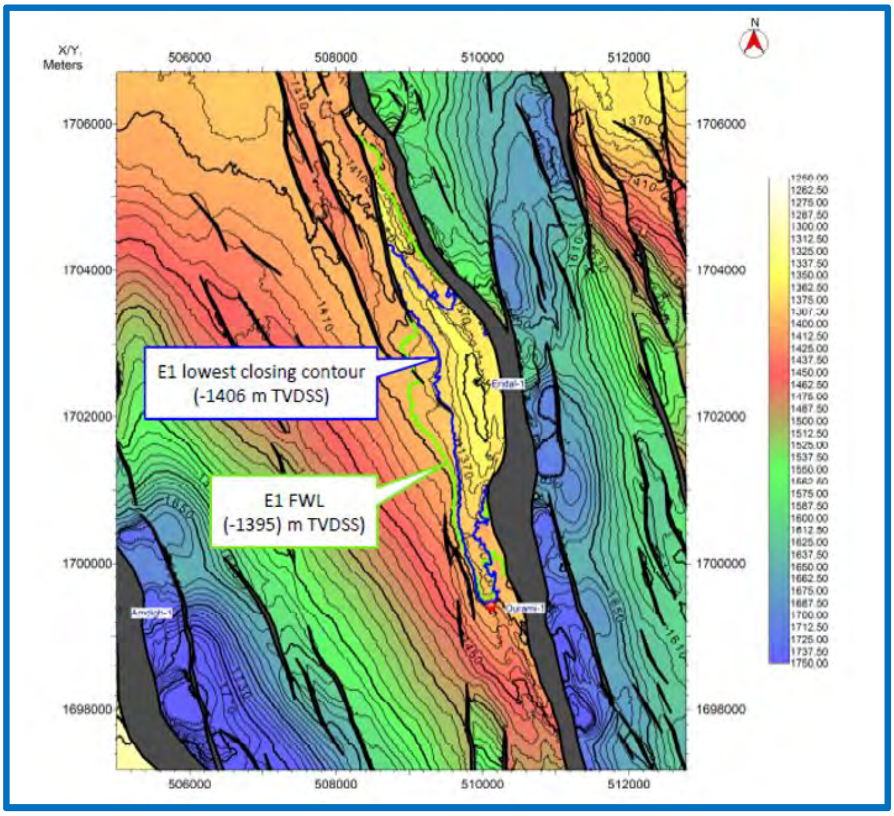


Figure 3-11 Eridal E1 structural depth map ***(based on PSTM dataset, source: Savannah, 2019)***

3.4.5 Zomo discovery

The Zomo-1 well was drilled on a structure immediately along strike from the Amdigh discovery and was drilled down to a TD of 2499 m MDBRT (2119 m TVDSS) after penetrating 97 m into the Madama Fm (**Figure 3-12** and **Figure 3-13**). The well encountered an oil column (5.4 m net pay) in the E1 interval of the Sokor Alternances. An oil sample was recovered with an API gravity of 23.7°.

An extensive RFT program was carried out in Zomo-1 to investigate its hydrocarbon column and possible relationship of the column to the proven columns in Amdigh-1. According to Savannah's interpretation, the RFT analysis proves that the oil columns in Zomo-1 and Amdigh-1 are separate.

Overall, the oils discovered in the five discoveries are medium to light (24º to 33º API) and "sweet" (<0.5 wt. % Sulphur) which is consistent with offset wells along trend and the depth/API trend observed across the basin.

Petrophysical analysis results in high calculated water saturations throughout the proven pay zone where oil was recovered. The implied low oil saturations are considered incompatible with the rest of the dataset for the well. Furthermore, oil producers in neighboring fields also exhibits low oil saturations based on petrophysical interpretation but are actually good oil producers. Therefore, the estimated pay has been adjusted by Savannah to take account of this uncertainty in water-saturation which CGG has judged a conservative approach to the net pay estimation.

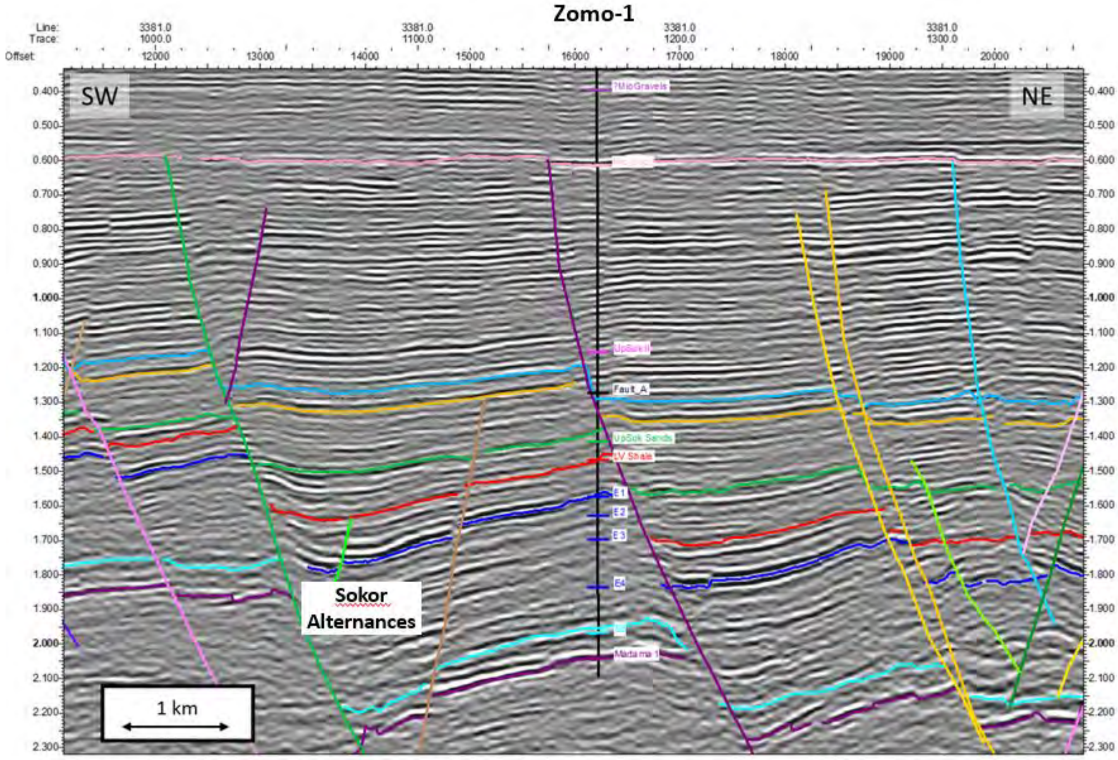


Figure 3-12 PSTM Seismic Section through Zomo-1 discovery well *(Source: Savannah, 2019)*

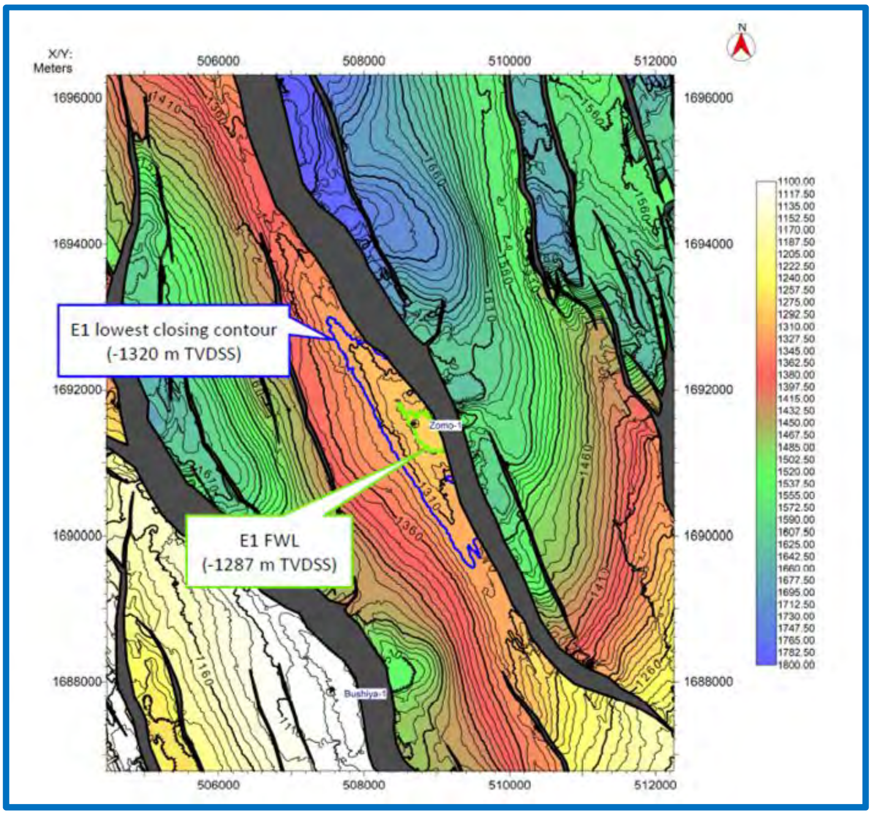


Figure 3-13 Zomo E1 structural depth map *(based on PSTM dataset, source: Savannah, 2019)*

3.5 Prospects and Leads

The high discovery rate (80%) within the Eocene Sokor Alternances 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, especially in the Cretaceous intervals.

Within the Sokor Alternances, the main risk is the fault seal which requires sand/shale juxtaposition. The historical drilling show that within this interval, 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, which the high success rate validates. 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**. The R3 Central area has only 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 3.3.1**, 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. In the future, 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. Several discoveries have been made in the Upper Yogou around the basin.

There have been numerous seismic programs in the area, comprising 2D lines of various vintages and modern 3D, as shown in **Figure 3-15**. The 3D surveys relevant to this review of the prospects are the R3 East 3D and the Dinga 3D, as outlined in red in **Figure 3-14**. The eleven prospects and leads reviewed by CGG are presented in **Figure 3-16.**

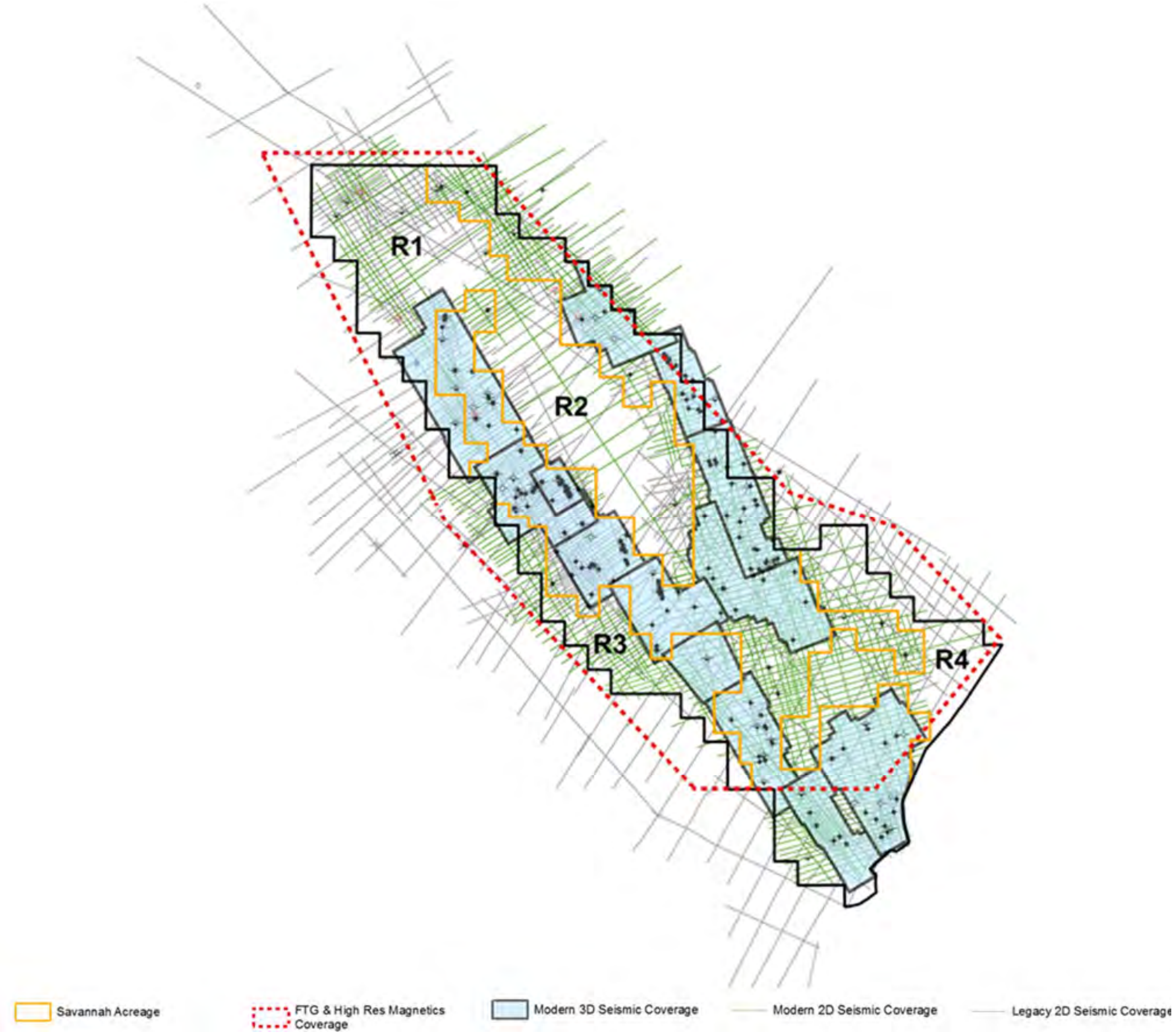


Figure 3-14 Seismic coverage in the Agadem Rift Basin ***(Source: Savannah, 2019)***

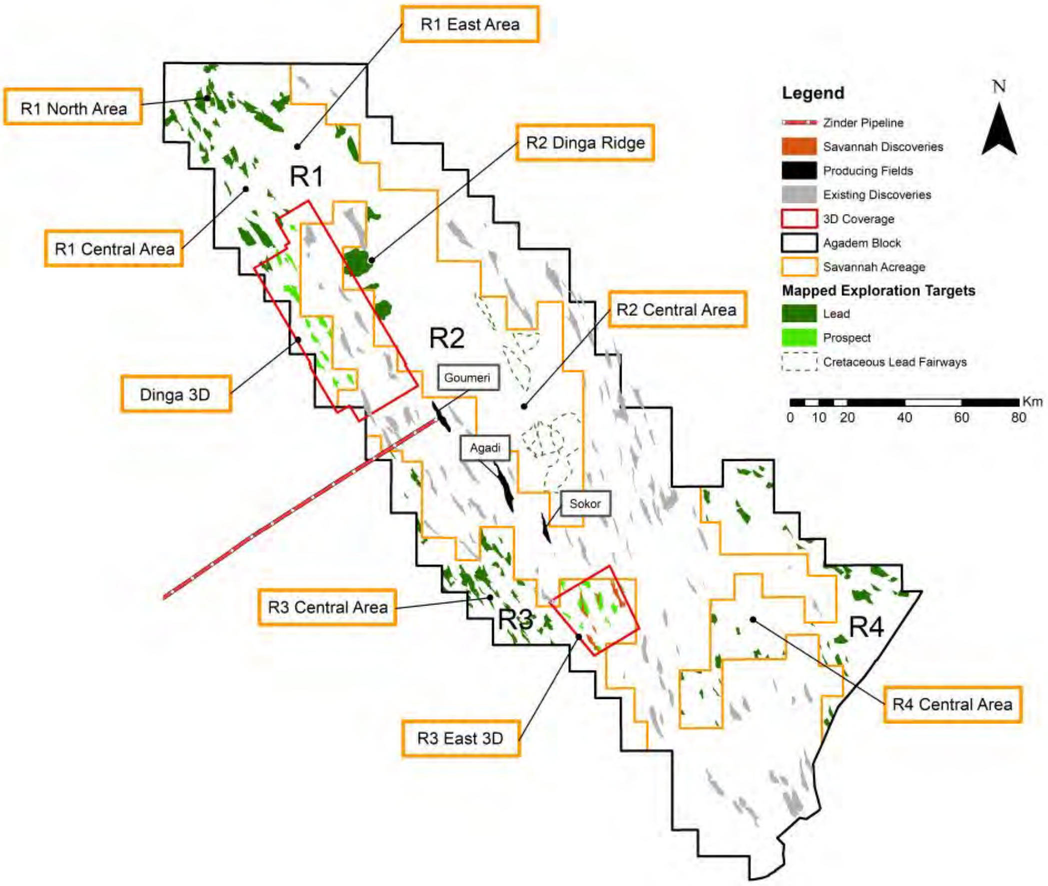


Figure 3-15 Savannah Prospects and Leads Portfolio with discovered fields and relevant 3D surveys (*Source: Savannah, 2019*)

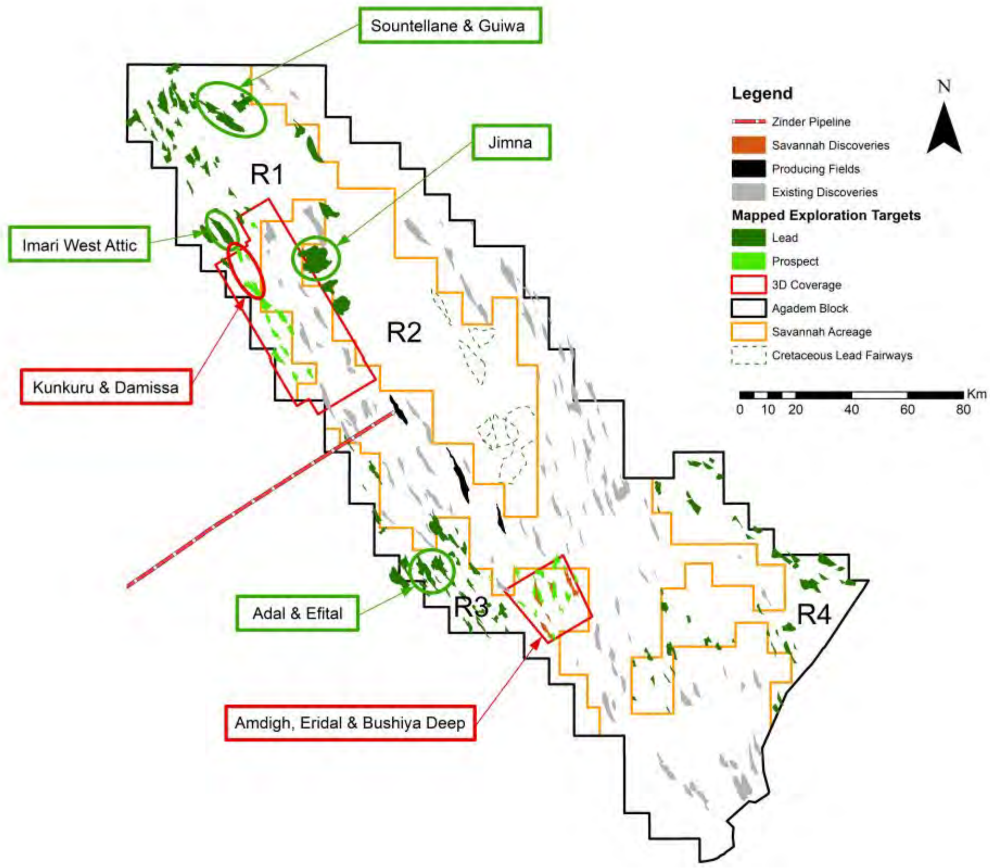


Figure 3-16 Map showing Prospects and Leads assessed by CGG (*Source: Savannah, 2019*)

4 RESOURCE ESTIMATION

4.1 Discoveries

CGG has estimated STOIIP and Resource volumes for the five discoveries resulting from Savannah's 2018 exploration drilling campaign. Based on the data provided, CGG made an independent estimation of the STOIIP with its own methodology to verify the estimated volumes of oil proposed by Savannah.

While visiting Savannah's offices (Data Room accessed November 11th, 2019), CGG got access to the seismic data of the R3 East 3D survey in Kingdom in order to verify the seismic interpretation and confirm the closure polygon areas selected for each discovery as inputs for the volumetric calculations.

Currently the depth conversion for the discoveries is based on the pre-drill depth map which has had a uniform shift applied for each individual discovery interval to tie the grid to the wells. A PSDM volume is currently being interpreted, which will use the velocity information at the wells and better constrain the geometries of the discoveries. Once this is interpreted the Contingent Resources numbers can be updated to reflect this new data.

Based on those structural maps, a series of Area-Depth tables were created by Savannah to use in their calculations for each discovery, reservoir and in the case of Amdigh even for each segment. These were used to estimate the Gross Rock Volume (GRV).

Additionally, the volumetric estimations performed by Savannah for each discovery and reservoir levels were made available which included all input parameters.

CGG have carried out an independent review of the available data to perform their own estimations of the in-place volume ranges. The results show an overall match between the two estimations. The alteration of the distributions generally leads to a slightly wider range of values but overall, only minor differences of small orders are observed.

The results of CGG estimations are summarised in the following tables:

Discovery	STOIIP (MMstb)		
	P90	**P50**	**P10**
Amdigh	31.3	65.9	254.3
Eridal	18.5	22.3	25.8
Bushiya	14.5	22.0	39.2
Kunama	8.0	14.9	28.1
Zomo*		0.7	
Total**	**72.4**	**125.1**	**347.4**

* Single deterministic case only, ** Arithmetic sum excluding Zomo
Total may not add exactly due to rounding

Table 4-1STOIIP to be developed by Discovery

It should be noted that in the case of Amdigh, only segments 1, 2 and 3 are assumed to be developed in the low and best cases. Therefore, **Table 4-1** does not include all the STOIIPS for the P90 and P50 cases. Amdigh total STOIIPs including all segments are 43.6 MMstb, 89.4 MMstb and 254.3 MMstb in the P90, P50 and P10 cases, respectively. Amdigh's STOIIP estimate show the discovery to be one of the ten largest in the basin.

Discovery	Contingent Resources (MMstb)		
	1C	2C	3C
Amdigh	7.2	18.4	83.9
Eridal	4.3	6.2	8.5
Bushiya	3.3	6.2	12.9
Kunama	1.8	4.2	9.3
Zomo*		0.2	
Total**	**16.7**	**35.0**	**114.6**

* Indicative Resources pending PSDM evaluation

** Arithmetic sum excluding Zomo, Total may not add exactly due to rounding

Table 4-2 Gross Contingent Resources

4.2 Prospects and leads

CGG has reviewed eleven exploration prospects and leads from the Savannah's portfolio. 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 in the Alternances 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).

The basis for sand thickness, porosity, oil saturation and FVF values were all found to be reasonable. Minimum and maximum areas of accumulation were, in almost all cases, also found to be reasonable, or were slightly modified by CGG for this review. The known traps are not filled to spill. The geological implications of this are discussed further in the discussion of "yet-to-find".

This review was undertaken to provide an independent validation of Savannah's numbers, as such a simplified version of the Savannah pay thickness approach was adopted, so that any differences in geological interpretation can be more readily compared.

The CGG depositional model summarised in **Section 3.2**, implies that "layer cake" geometries may apply to many of the reservoirs. **Section 5.3** 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 28% 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 portion of the R1/R2/R4 Licence Area.

4.2.1 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 oil or bitumen whilst drilling through the shallow section. In the data reviewed, only six of the many wells drilled in this basin are reported to contain oil accumulations in the Upper Sokor and shallower section. However, the vast majority of the Upper Sokor penetrations were not drilled in closure and therefore this play remained largely under-explored.

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 due 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.

4.2.2 Risk factors

The standard industry methodology of assigning probabilities to the different components of the petroleum system 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 to be 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.

The results from the five exploration wells confirm the prediction, both by CGG and Savannah, that the Alternances targets are low risk; oil was found in all five wells in this interval. The shallower level Upper Sokor targets were predicted to be high risk, and oil accumulations were not found at this level in any of the five wells.

4.2.3 STOIIP and Prospective Resource estimation

The table below summarises CGG's assessment of the STOIIP and Prospective Resources for the prospects and leads shown in **Figure 3-16**. This table only presents 11 out of 146 prospects and leads identified by Savannah. Recovery factors of 23%, 28% and 33% 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 5.0**.

			STOIIP (MMstb)			
Area	**Prospect/lead**		**P90**	**P50**	**P10**	**Mean**
R3 East	Bushiya Deep	Yogou Prospect	8.0	27.3	68.1	33.6
R3 East	Amdigh Deep	Yogou Prospect	11.2	39.1	99.0	48.6
R3 East	Eridal Deep	Yogou Prospect	7.4	24.8	60.5	30.3
R3 Central	Adal	Lead Total	13.9	73.6	220.0	87.8
R3 Central	Efital	Lead Total	37.8	157.0	394.0	170.0
R1	Sountellane	Lead Total	40.7	128.0	328.0	161.0
R1	Damissa	Prospect Total	57.4	239.0	570.0	283.0
R1	Imari West Attic	Lead Total	38.1	162.0	453.0	211.0
R1	Guiwa	Upper Sokor Lead	28.2	107.0	272.0	132.0
R1	Kunkuru	Prospect Total	8.2	37.3	94.9	45.6
R2	Jimna	Yogou Lead	74.8	291.0	772.0	130.0
Total*			**325.7**	**1286.1**	**3331.5**	**1332.9**

* Arithmetic sum

Notes:

1. *The volumes for individual prospect and lead totals are calculated probabilistically*

Table 4-3 Unrisked STOIIP by Prospect and Lead (for a subset of 11 out of 146 prospects/leads portfolio)

Area	Prospect/lead		Unrisked Prospective Resources (MMstb)				
			Gross				
			Low Estimate	Best Estimate	High Estimate	Risk factor	Operator
R3 East	Bushiya Deep	Yogou Prospect	1.8	7.6	22.5	medium	Savannah
R3 East	Amdigh Deep	Yogou Prospect	2.6	10.9	32.7	medium	Savannah
R3 East	Eridal Deep	Yogou Prospect	1.7	6.9	20.0	medium	Savannah
R3 Central	Adal	Lead Total	3.2	20.6	72.6	medium	Savannah
R3 Central	Efital	Lead Total	8.7	44.0	130.0	medium	Savannah
R1	Sountellane	Lead Total	9.4	35.8	108.2	medium	Savannah
R1	Damissa	Prospect Total	13.2	66.9	188.1	low	Savannah
R1	Imari W Attic	Lead Total	8.8	45.4	149.5	high	Savannah
R1	Guiwa	Upper Sokor Lead	6.5	30.0	89.8	high	Savannah
R1	Kunkuru	Prospect Total	1.9	10.4	31.3	low	Savannah
R2	Jimna	Yogou Lead	17.2	81.5	254.8	high	Savannah
	Total*		**74.9**	**360.1**	**1099.4**		

Notes:

1. *The volumes for individual prospect and lead 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*
   Risk factor: low = > 75%, medium = 25% - 75%, high = <25%

**Arithmetic sum*

Table 4-4 Unrisked Prospective Resources by Prospect and Lead (for a subset of 11 out of 146 prospects/leads portfolio)

4.3 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 result in different trap sizes 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. **Table 4-5** summarises our overall assessment of the Low, Best and High Case estimates, both unrisked and risked, for the areas R1/R2/R4 and R3.

	Gross Prospective Resources – "yet to find" (MMstb)					
	Unrisked			Risked		
Licence	**Low estimate**	**Best estimate**	**High estimate**	**Low estimate**	**Best estimate**	**High estimate**
R1/R2/R4	2156	5675	8456	851	2239	3337
R3	405	1126	1531	149	456	531
Total*	**2561**	**6801**	**9987**	**1000**	**2695**	**3868**

* Arithmetic sum

Table 4-5 Unrisked and risked gross "Yet to Find" prospective resource estimates

Across the areas as a whole, the estimated average play geological chance of success (GCOS) for the Alternances in exploration terms is high (>75%). The lower 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.

5 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.

5.1 Discovery PVT Evaluation

PVT samples were taken in four of the 2018 R3 East discovery wells. Downhole samples were retrieved in all cases via the wireline RFT tool. The samples are summarised below in **Table 5-1**. Overall, the discovered oils are medium to light (24 º to 33 º API) with a low sulphur content (<0.5 wt. %).

Indicator	Unit	Bushiya-1	Amdigh-1	Kunama-1	Eridal-1
Depth	mMD	1476.8	1712.4	1673.8	1719.4
E-Sequence		E1	E1	E1	E1
Type		Dead Oil	Dead Oil	Dead Oil	Dead Oil
Oil Density	g/cm³	0.9078	0.8893	0.8861	0.8591
Oil API @ 60ºF	°API	24.2	27.5	28	33.0

Table 5-1 Summary of Down hole samples

Savannah has used the Corelab PVT laboratory analysis results, alongside knowledge of offset well oil characteristics from previous analogue studies, to construct PVT models for use in production modelling. These PVT models were constructed within the industry-standard Petroleum Experts MBAL software package. The PVT models were applied for modelling both within MBAL as well as Petroleum Experts PROSPER (well modelling). Oil properties within the PVT models were varied with pressure/temperature by utilising PVT correlations from the literature.

5.2 Discovery Reservoir modeling

Savannah have built a Material Balance model using Petroleum Experts MBAL software for the 2018 discoveries. This R3 East MBAL model has been utilised primarily to:

- Capture and collate the data collected as part of the 2018 drilling program and learnings from prior and ongoing studies of Agadem Rift Basin (ARB) analogues into a model of the discovered reservoirs
- Simulate development scenarios to capture a range of potential production outcomes
- Conduct sensitivities to key uncertainties – importantly STOIIP & aquifer strength

Production profiles created from this model have been based on all available data and are specific to the underlying reservoir, well and project constraint assumptions of the scenario, many of which are uncertain. In order to be able to improve the prediction of water influx rates and timing, type curves have been derived from analogue fields.

5.3 Recovery factor estimation

The recovery factor is the recoverable amount of hydrocarbon-initially-in-place, normally expressed as a percentage. CGG has reviewed the MBAL work that has been carried out by Savannah with investigated Recovery Factor Sensitivity based on varying Aquifer Strength and water injection strategy. In light of the previous work that has been done on recovery factor estimation in the pre well estimates and the review of analogy and Empirical correlations the approach that has been used is viewed as reasonable. CGG has applied recovery factors presented in **Table 5-2** to the STOIIP figures to calculate recoverable volumes.

Case	R.F. %
Low	23.0
Mid	28.0
High	33.0

Table 5-2 Summary of recovery factor used for resource assessment

Figure 5-1 shows the base case from the MBAL model used in the indicative economics which demonstrates that Savannah is being conservative in its approach to the development and expected Ultimate Recovery. CGG have reviewed the assumptions and inputs into the MBAL model and believes that it has been built in a through manner and does not overstate the potential from the discoveries given the uncertainties and lack of well test data at this time.

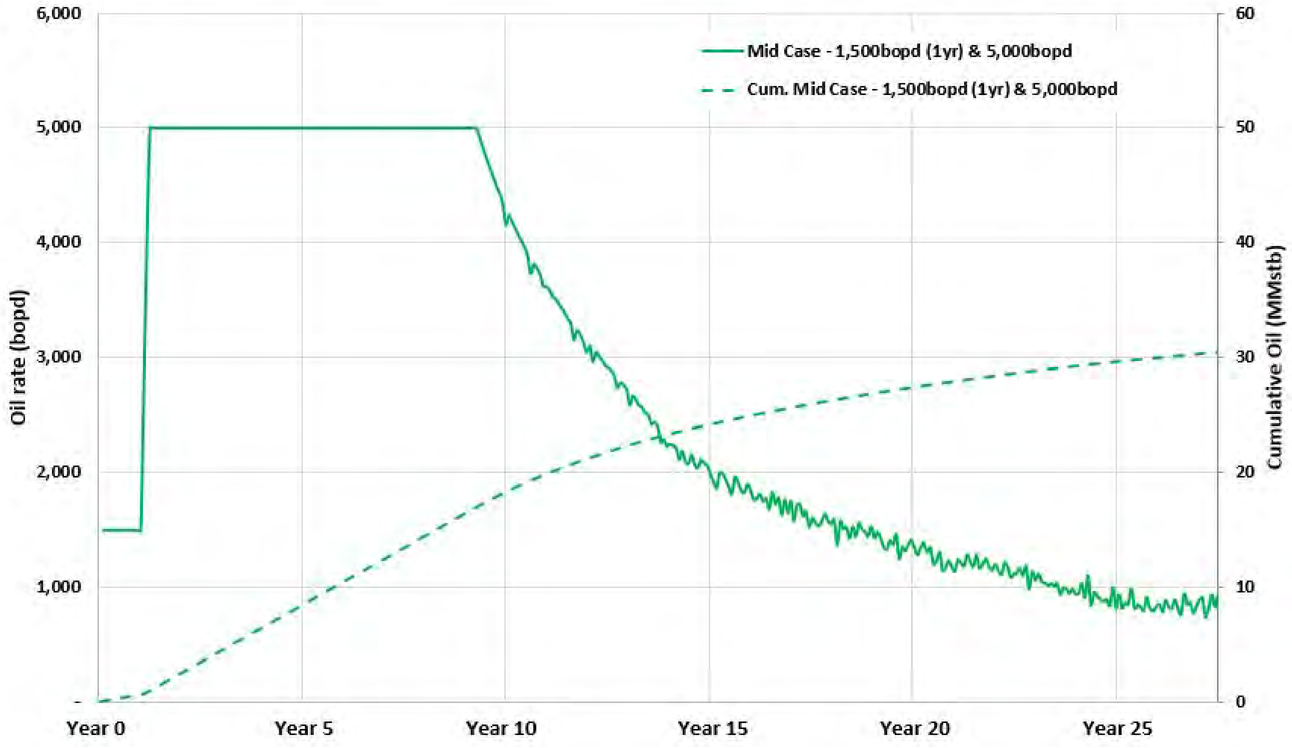


Figure 5-1 Base case Oil forecast for R3 East discoveries

6 DEVELOPMENT SCENARIOS

Savannah have prepared an early development scheme for exploiting the recent oil discoveries made by the company in the R3 Licence area. This development scheme is described and reviewed by CGG in the following sections.

Three fields (namely Goumeri, Sokor and Agadi) are on production in close proximity to the recent Savannah discoveries. CNPC currently sells domestically to the c. 20 kbpd capacity Zinder refinery, via the 463 km Agadem to Zinder domestic pipeline. The Société de Raffinage de Zinder (SORAZ) which operates the refinery, is a joint venture between CNPC (60%) and the Niger government (40%).

6.1 R3 East – Early Production Scheme

An Early Production Scheme has been proposed by Savannah, based on existing developments in the basin. The facility would be located at the Amdigh discovery, given its size and location relative to potential export routes. It is planned to develop the discoveries in two phases:

- Phase 1 – EPF (Early Production Facility) and trucking
- Phase 2 – CPF (Central Processing Facility) and pipeline crude evacuation

Figure 6-1 outlines the key components of the scheme.

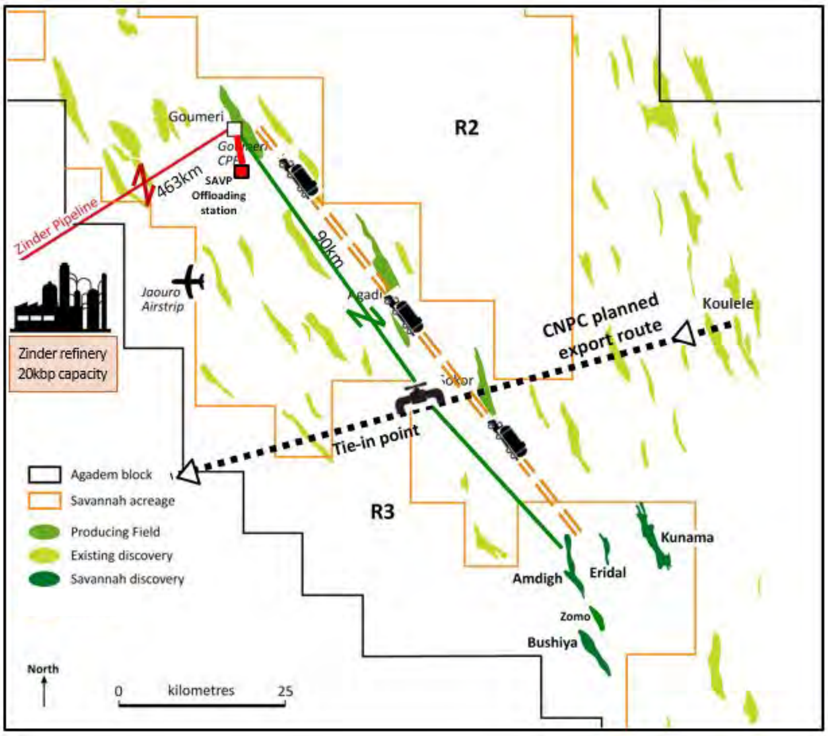


Figure 6-1 Proposed Early Production Scheme Development ***(Source: Savannah, 2019)***

6.1.1 Phase 1 – Trucking

Phase 1 involves production testing of the Amdigh-1 and Eridal-1 wells, with production processed using a leased EPF. Crude would then be trucked 120 km to the Goumeri Export Station, from where it would be transported to the SORAZ (Société de Raffinage de Zinder) refinery near Zinder via the existing CNPC operated 463km Agadem-Zinder pipeline. Expected plateau rates are c. 1,500 bopd, which is scheduled after the completion of the Amdigh-1 and Eridal-1 well testing.

The key components of the Phase 1 development are detailed in **Figure 6-2**.

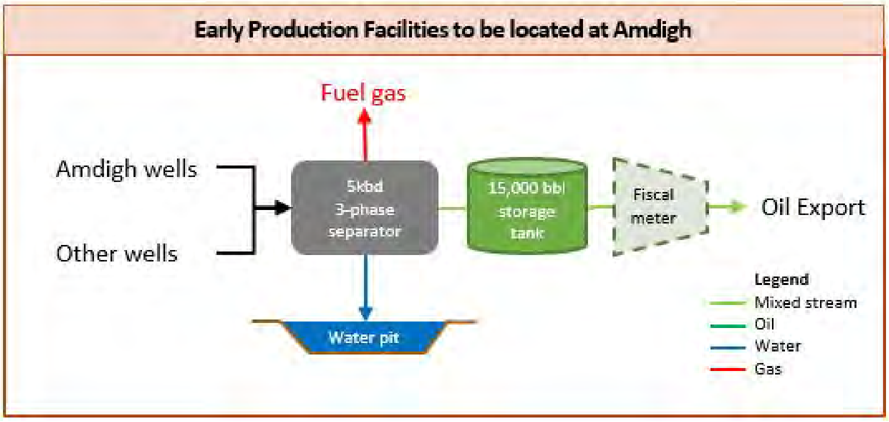


Figure 6-2 R3 East Early Production Facilities *(Source: Savannah, 2019)*

The facilities will be a leased Early Production Facilities (EPF), which will permit early revenues before the permanent CPF is installed and commissioned.

Total capital costs for Phase 1 have been estimated and are detailed in **Table 6-1**.

Item	**Cost, US$MM**
Completion of Amdigh-1 and Eridal-1 wells including pumps	3.4
EPF lease cost (over 2 years)	8.1
Goumeri unloading station	1.0
Unloading station to Goumeri pipeline	0.3
Eridal to Amdigh flowline	0.7
Civils works	0.9
Total	**14.4**

Table 6-1 Phase 1 Capex Estimate

Operating costs for Phase 1 are estimated at US$0.6MM per month, consisting of EPF, pipeline, unloading station, water treatment and allocated in-country overhead costs. An additional US$0.013MM per month per well is estimated for pump fuel.

Trucking costs are estimated to be US$12.5 per barrel, and operating costs for the Goumeri to Zinder pipeline are shared with CNPC on a throughput basis assuming a total capacity of 15,000 bopd and a total annual cost of US$32.9MM per year. Based on the 1,500 bopd plateau rate, this equates to approximately US$0.25MM per month.

CGG has reviewed the proposed development solution and costs for Phase 1, and consider them to be reasonable.

6.1.2 Phase 2 – Pipeline Crude evacuation

Depending on the results of the well tests in Phase 1, a Central Processing Facility (CPF) will most likely be built at Amdigh. The other discoveries, namely Bushiya, Kunama, Eridal, will then be tied-back to the CPF via inter field flowlines. Export will be via a new 90 km pipeline to the Goumeri Export Station.

The CPF will be designed for a plateau rate of 5,000 bopd, which is scheduled to be achieved one year after first oil. Total capital costs for Phase 2 have been estimated and are detailed in **Table 6-2**. This cost will be spread over the full life of field.

The total external funding requirement for Phase 1 and Phase 2, prior to the project becoming self-funding, is estimated at US$57.7m (2020 prices).

Item	**Cost, US$MM**
Amdigh to Goumeri pipeline	16.9
Inter-field flowlines	1.8
Production/Injection wells (x21)	146.4
Intra field flowlines	4.3
Water treatment	4.0
Export station	0.5
Total	**173.9**
Phase 1 & 2 external funding requirement	***57.7***

Table 6-2 Phase 2 Capex Estimate

Operating costs for Phase 2 are estimated at US$0.7MM per month, consisting of CPF, pipeline, unloading station, water treatment, and allocated in-country overhead costs. An additional US$0.013MM per month per well is estimated for pump fuel, giving an additional US$0.3MM per month cost once all wells are operating.

Operating costs for the Goumeri to Zinder pipeline are shared with CNPC on a throughput basis assuming a total capacity of 15,000 bopd and a total annual cost of US$32.9MM per year. Based on the 5,000 bopd plateau rate, this equates to approximately US$0.68MM per month (equivalent to c. US$4.5 per barrel).

Abandonment costs are assumed to be 15% of Phase 1 and Phase 2 Capex.

CGG has reviewed the proposed development solution and costs for Phase 2, and consider them to be reasonable.

6.2 Export Pipeline Construction

Existing production in the Agadem Rift Basin (ARB) is currently transported through a 463 km pipeline to the domestic Zinder refinery, located in the south of Niger. However, as the refinery has an approximate nominal capacity of only 20,000 bopd, an alternative evacuation route is required in order to maximise production from within the ARB where up to 1 Bbbl of 2P Reserves have been proven by CNPC in the adjacent licences to Savannah.

To meet this requirement in September 2019 CNPC signed a Transportation Convention with the government of Niger to construct a 2,000 km oil export pipeline running from Koulele in Agadem (near the R3 Licence) to Port Seme on the Atlantic coast in Benin (**Figure 6-3**) (1,298 km in Niger, 684 km in Benin). This is understood to be CNPC's largest cross-border pipeline and is estimated to cost in the region of US$7 billion. CNPC have issued guidance on completion being at the end of 2021.

Under the terms of the R1/R2/R4 and R3 PSCs, Savannah has access to Third Party infrastructure under terms that guarantee the owner a 12.5% return. On this basis Savannah estimate that the pipeline tariff would be in the order of US$14 per barrel in 2020 terms.

The development schemes for Savannah's discoveries to date outlined in this report, do not assume usage of this export pipeline. However, due to its proximity to the R3 East discoveries and Savannah adjacent prospects, it does offer an alternative route to realise the full potential of the Savannah's assets.

Figure 6-3 Proposed Route of Niger to Benin Export Pipeline

7 INDICATIVE ECONOMICS

7.1 Methodology

Net Present Values (NPVs) have been calculated using Savannah's Excel™ economic model of the R3/R4 PSC. The model has been subject to a high-level review by CGG, and found to be in agreement with the fiscal and commercial terms applicable to the contract area.

7.2 Input assumptions

7.2.1 Fiscal terms

Savannah's licences are subject to two different sets of fiscal terms.

- The R1/R2/R4 Licence Area is subject to a Production Sharing Contract (PSC) between Savannah Petroleum Niger S.A. (the Contractor) and the Republic of Niger.
- The R3 Licence Area is subject to a Production Sharing Contract (PSC) between Savannah Petroleum Niger 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.

7.2.1.1 Historical signature bonuses:

- R1/R2 PSC US$34MM of which 40% is cost recoverable
- R3/R4 PSC US$28MM of which 60% is cost recoverable

These were paid at the signing of the two contracts.

7.2.1.2 Royalties:

There is an oil royalty of 12.5% levied on the gross sales revenue less export pipeline costs.

7.2.1.3 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. Savannah estimate that approximately $125MM of costs related to R3/R4 PSC are unrecovered as of 2019 year-end.

7.2.1.4 Profit oil:

Profit oil is shared between the State and Savannah depending on the value of an R-factor as shown in **Table 7-1**. The R-factor is calculated as follows:

(cumulative cost and profit oil less exploitation costs)/ (cumulative exploration and capital costs)

R-Factor	Contractor	State
< 1.0	60%	40%
1.0 – 1.49	55%	45%
1.5 -1.99	50%	50%
> 2.0	45%	55%

Table 7-1 Profit Oil rates

7.2.1.5 Corporation tax:

No corporation tax is payable in Niger.

7.2.1.6 State participation:

The state has back-in rights to the licences as follows:

- R1/R2/R4: 20% of profit oil
- R3: 15% of profit oil

7.2.2 Oil prices

It is understood from Savannah that currently production from the ARB is sold to the SORAZ refinery at a government agreed fixed price of US$42 per barrel. From July 2022, when the CNPC Niger-Benin export pipeline has come online we expect export parity between the domestic price and the price that can be realised for the oil when exported to be achieved. It is assumed that from July 2022 the realised price at the refinery gate will be equivalent to the Brent price less a discount of US$9.5 per barrel to account for the expected Niger-Benin pipeline transportation costs.

Based on bank consensus forecasts as of 16th April 2020, Brent prices have been assumed as tabulated below.

Year	Brent Price (US$/bbl)
2022	55.0
2023	60.0
2024	62.4
2025	+2% pa

Table 7-2 Oil Price Forecast

7.2.3 Other

Other assumptions used by CGG in the economic evaluation are tabulated below.

Parameter	Value
Discount Factor	10%
Discount Methodology	Monthly
Cost Inflation[1]	2% per annum
Discount Date	31 March 2020

1. Savannah believe that they will be able to "lock into" current contract rates for the early phases of the development, and therefore costs for these phases has not been inflated in the evaluation.

Table 7-3 Other assumptions

7.3 Results

Indicative economics have been determined for the 2C resource case. The economics presented are net to Savannah's 95% interest, and assume that Savannah are able to achieve first production from Phase 1 in January 2021.

Case	2C
NPV0 (US$MM)	358.9
NPV10 (US$MM)	132.8
NPV10/bbl (US$)	5.8

Notes

1. *NPVs are based on net production of 23 MMstb post economic cut-off and 15% government back-in right*

Table 7-4 Indicative economics (net Savannah) for Discoveries

NPV10 sensitivities for each resource case have also been performed for +30%/-15% factors on costs, and +25%/-25% factors on oil price. The results of this analysis are tabulated below.

The break-even domestic oil price which would enable Savannah to generate a 10% IRR on the development would be approximately US$26/bbl, assuming costs would be reduced at this oil price level by at least 20% from those prevailing at a long-term US$60/bbl assumption, which CGG has assessed as reasonable.

As a sensitivity, the economics of tying-in a 20 MMstb prospect to the Amdigh facilities have also been evaluated. On the basis of minimal modifications to the facilities, this analysis yielded an incremental unrisked NPV10 of approximately $100mn net to Savannah.

Case	2C
Base case	132.8
+30% factor on costs	74.9
-15% factor on costs	158.2
Oil price +25%	200.9
Oil price -25%	49.0
Production volume +25%	192.9

Table 7-5 Sensitivities for Indicative Economics (NPV10, US$MM)

8 APPENDIX A: DEFINITIONS

8.1 Definitions

The petroleum reserves and resources definitions used in this report are in accordance with the Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE).

The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

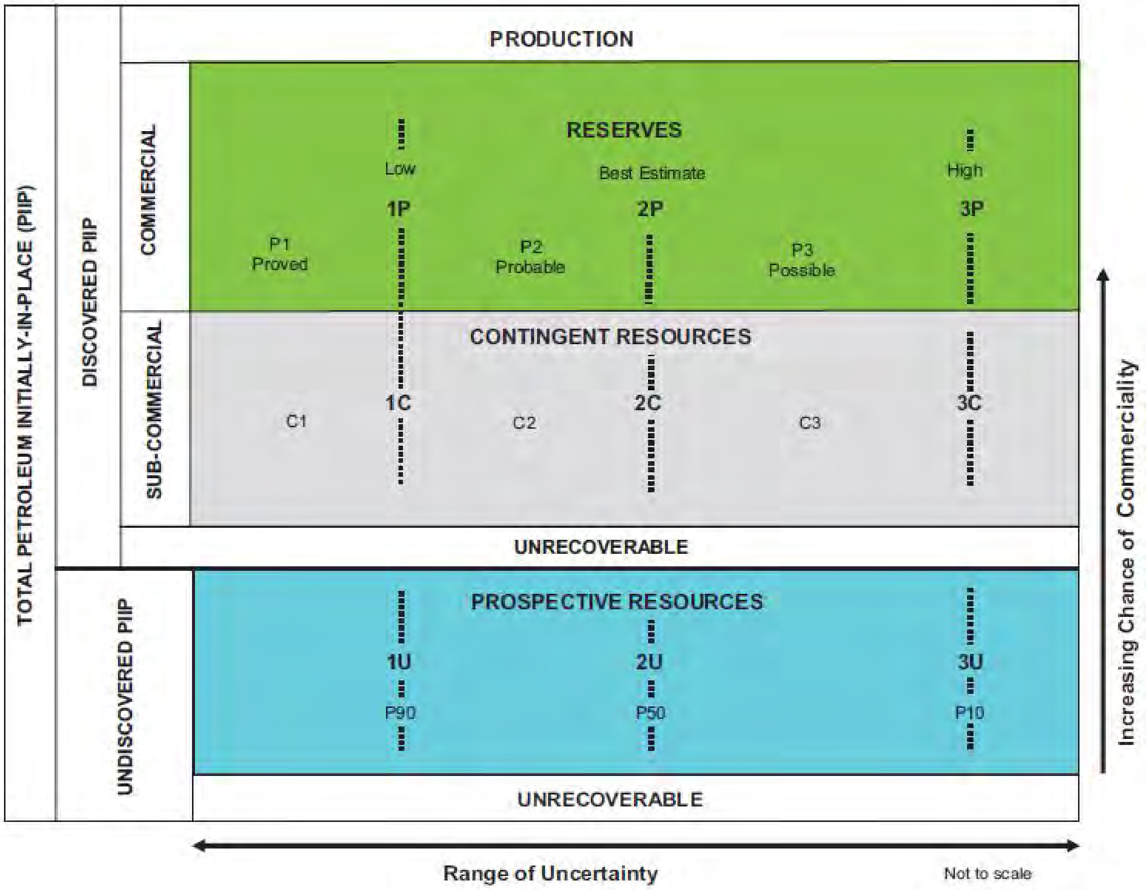


Figure 7-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System, 2018)

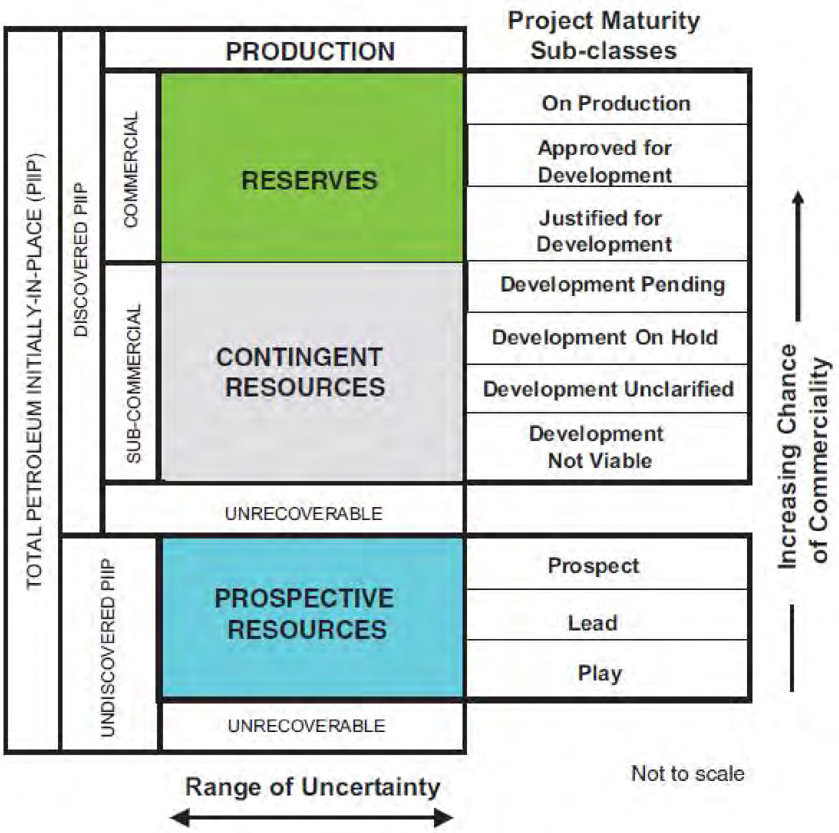


Figure 7-2 Resources Classification Framework: Sub-classes based on Project Maturity

(Source: SPE Petroleum Resources Management System, 2018)

8.1.1 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”).

8.1.2 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.

8.1.3 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.

8.2 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.

8.3 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.

8.3.1 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.

8.3.2 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.

8.3.3 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.

8.3.4 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.

8.3.5 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.

8.3.6 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.

8.4 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.

8.4.1 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.

8.4.2 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.

8.4.3 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.

8.5 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.

8.5.1 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.

8.5.2 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.

8.5.3 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.

8.6 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.

9 APPENDIX B: NOMENCLATURE

acre	43,560 square feet
AOF	absolute open flow
API	American Petroleum Institute (ºAPI 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
M	thousands
MM	million
m^3/day	cubic metres per day
Ma	million years (before present)

mbdf	metres below derrick floor	pbu	pressure build-up
mbsl	metres below sea level	perm.	permeability
MBOPD	thousand bbls of oil per day	PESGB	Petroleum Exploration Society of Great Britain
MCFD	thousand cubic feet per day	pH	-log H ion concentration
MCFGD	thousand cubic feet of gas per day	phi	unit grain size measurement
mD	millidarcies	Ø	porosity
MD	measured depth	plc	public limited company
mdst.	mudstone	por.	porosity
MFS	maximum flooding surface	poroperm	porosity-permeability
mg/gTOC	units for hydrogen index	ppm	parts per million
mGal	milligals	psi	pounds per square inch
MHz	megahertz	RFT	repeat formation test
million m^3	million cubic metres	ROI	return on investment
ml	millilitres	ROP	rate of penetration
mls	miles	RT	rotary table
MMBO	million bbls of oil	S	South
MMBOE	million bbls of oil equivalent	SCAL	special core analysis
MMBOPD	million bbls of oil per day	SCF	standard cubic feet, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
MMCFGD	million cubic feet of gas per day	SCF/STB	standard cubic feet per stock tank barrel
MMTOE	million tons of oil equivalent	SS	sub-sea
mmsl	metres below mean sea level	ST	sidetrack (well)
mN/m	interfacial tension measured unit	STB	stock tank barrels
MPa	megapascals	std. dev.	standard deviation
mSS	metres subsea	STOIIP	stock tank oil initially in place
m/s	metres per second	Sw	water saturation
msec	millisecond(s)	TCF	trillion (10^{12}) cubic feet
MSL	mean sea level	TD	total depth
N	north	TDC	tangible drilling costs
NaCl	sodium chloride	Therm	105 Btu
NFW	new field wildcat	TVD	true vertical depth
NGL	natural gas liquids	TVDSS	true vertical depth subsea
NPV	net present value	TVDmsl	true vertical depth below MSL
no.	number (not #)	TWT	two-way time
NTG	Net toGross	US$	US dollar, the currency of the United States of America
OAE	oceanic anoxic event	UV	ultra-violet
OI	oxygen index	VDR	virtual dataroom
OWC	oil-water contact		
P90	proved		
P50	proved + probable		
P10	proved + probable + possible		
P & A	plugged & abandoned		

W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)

PART 10

ADDITIONAL INFORMATION

1. RESPONSIBILITY

1.1 The Company and its Directors (whose names and functions appear on page 5 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 CGG Services (UK) Limited, whose registered address is at Crompton Way, Manor Royal Estate, Crawley, West Sussex, RH10 9QN, accepts responsibility for its reports set out in Parts 8 and 9 of this document. To the best of the knowledge and belief of CGG Services (UK) Limited (which has taken all reasonable care to ensure that such is the case), the information contained in its reports are in accordance with the facts and do 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 09115262), as a public limited company under the Act. The Company changed its name to Savannah Energy PLC on 16 April 2020.

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 Re-Admission.

2.5 The website address for the Company for the purposes of AIM Rule 26 is www.savannah-energy.com.

2.6 The principal legislation under which the Company operates 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.

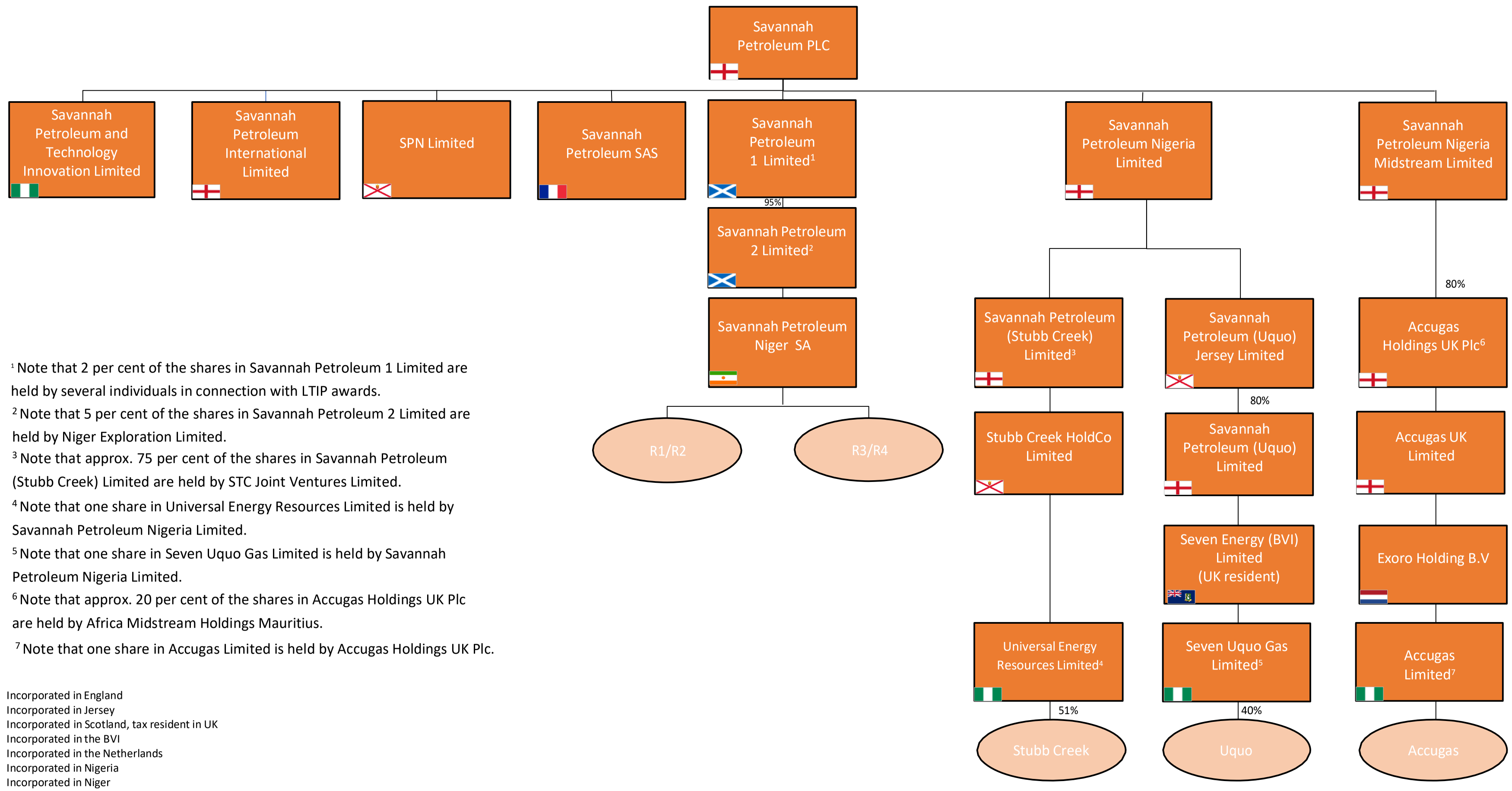
2.9 The Company is the ultimate holding company of the Group. On Re-Admission, the Company will have the following subsidiaries and other undertakings:

Name (Jurisdiction)	*Registered Office*	*Principal Activity*	*Issued Share Capital*
Savannah Petroleum 1 Limited (Scotland – SC453751)	50 Lothian Road, Festival Square, Edinburgh, Midlothian, EH3 9WJ	Subsidiary company	15,737,894 A1 ordinary shares of $0.000000001 each, two A2 ordinary shares of £0.000000001 each and 1,000,000,020 B ordinary shares of $0.000000001 each
Savannah Petroleum 2 Limited (Scotland – SC467099)	50 Lothian Road, Festival Square, Edinburgh, Midlothian, EH3 9WJ	Subsidiary company	105,264 ordinary shares of $0.00001 each
Savannah Petroleum Niger S.A. (Niger-RCCM NI-NIA-2014-B1940)	124 Rue des Ambassades AM-8, BP 11272, Niamey, Niger	Exploration and extraction of petroleum & natural gas	1,000 shares of CFA 10,000 each
SPN Limited (Jersey – 117216)	11 Bath Street, St Helier, Jersey, JE4 8UT	Subsidiary company	10,000 limited liability shares of £1.00 each
Savannah Petroleum SAS (France – 811 283 043)	3-5 Rue Saint-Georges, 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
Savannah Petroleum Nigeria Midstream Limited (England – 11685648)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	1 ordinary share of $1.00
Savannah Petroleum Nigeria Limited (England – 11290084)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	1 ordinary share of $1.00
Savannah Petroleum (Stubb Creek) Limited (England – 11309541)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	75 A ordinary shares of $1.00 each and 25 B ordinary shares of $1.00 each
Accugas Holdings UK plc (England – 11950135)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	62,502 ordinary shares of £1.00 each
Accugas UK Limited (England – 12257421)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	3 ordinary shares of £1.00 each
Exoro Holding B.V. (Netherlands – 27307262)	6 Chesterfield Gardens, London, W1J 5BQ	Subsidiary company	18,769 shares of €1.00 each

Name (Jurisdiction)	*Registered Office*	*Principal Activity*	*Issued Share Capital*
Accugas Limited (Nigeria – 881197)	35 Kofo Abayomi Street, Victoria Island, Lagos State	Gas processing, marketing and distribution	10,424,329 shares of NGN 1.00 each
Stubb Creek Holdco Limited (Jersey – 128339)	11 Bath Street, St Helier, Jersey, JE4 8UT	Subsidiary company	302 shares of $0.01 each
Universal Energy Resources Limited (Nigeria – 429120)	25 Idoro Road, Uyo, Akwa Ibom State, Nigeria	Exploration and extraction of petroleum & natural gas	480,000,000 shares of NGN 1.00 each
Savannah Petroleum (Uquo) Jersey Limited (Jersey – 130188)	11 Bath Street, St Helier, Jersey, JE4 8UT	Subsidiary company	3 shares of $1.00 each
Savannah Petroleum (Uquo) Limited (England – 12292632)	40 Bank Street, London, United Kingdom, E14 5NR	Subsidiary company	1,250 ordinary shares of $0.001 each
Seven Energy (BVI) Limited (British Virgin Islands – 1032686)	Midocean Chambers PO Box 805, Road Town Tortola, British Virgin Islands, Virgin Islands	Subsidiary company	56,068,924 class no. 1 ordinary shares with no par value
Seven Uquo Gas Limited (Nigeria – 659675)	35 Kofo Aboyomi Street, Victoria Island, Lagos, Nigeria	Exploration and extraction of petroleum & natural gas	100,000,000 shares of NGN 1.00 each
Savannah Petroleum & Technologies Innovations Ltd (Nigeria – 1399618)	18/24 Ajisegiri Str, Oshodi, Lagos	Subsidiary company	10,000,000 shares of NGN 1.00 each

2.10 A structure chart showing the principal members of the Group is shown below:

Figure 46, Group Structure Chart



[1] Note that 2 per cent of the shares in Savannah Petroleum 1 Limited are held by several individuals in connection with LTIP awards.

[2] Note that 5 per cent of the shares in Savannah Petroleum 2 Limited are held by Niger Exploration Limited.

[3] Note that approx. 75 per cent of the shares in Savannah Petroleum (Stubb Creek) Limited are held by STC Joint Ventures Limited.

[4] Note that one share in Universal Energy Resources Limited is held by Savannah Petroleum Nigeria Limited.

[5] Note that one share in Seven Uquo Gas Limited is held by Savannah Petroleum Nigeria Limited.

[6] Note that approx. 20 per cent of the shares in Accugas Holdings UK Plc are held by Africa Midstream Holdings Mauritius.

[7] Note that one share in Accugas Limited is held by Accugas Holdings UK Plc.

Incorporated in England
Incorporated in Jersey
Incorporated in Scotland, tax resident in UK
Incorporated in the BVI
Incorporated in the Netherlands
Incorporated in Nigeria
Incorporated in Niger
Incorporated in France

2.11 As detailed in figure 46 above, 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.

2.12 The Company owns indirectly:

2.12.1 (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 Managing Director in Niger;

2.12.2 (via Savannah Petroleum Nigeria Limited) 25 B ordinary shares in the capital of Stubb Creek Topco and STC Joint Venture Limited is the holder of the other 75 A ordinary shares in the capital of Stubb Creek Topco. The shareholders' agreement between Savannah Petroleum Nigeria Limited and STC Joint Venture Limited is described in paragraph 5.6 of Part 11 of this document; and

2.12.3 (via Savannah Petroleum Nigeria Midstream Limited) 50,002 ordinary shares in Accugas Holdings UK plc and Africa Midstream Holdings Mauritius (a subsidiary of AIIM) is the holder of the other 12,500 ordinary shares in issue.

2.13 Savannah Niger, Accugas Limited, SUGL and Universal Energy Resources Limited are the principal operating subsidiaries of the Group.

3. SHARE CAPITAL

3.1 The share 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 Lothian Capital Partners 1 Limited (**"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 18 July 2015, 43,779,000 Ordinary Shares were issued (being the first tranche of new Ordinary Shares issued in July 2015) as part of a placing of new Ordinary Shares in the Company for an issue price of £0.38 per Ordinary Share.

3.1.6 On 30 July 2015, 314,275 Ordinary Shares were issued to certain of the Company's Directors and employees by way of bonus remuneration at an effective subscription price of £0.4012 per Ordinary Share.

3.1.7 On 3 August 2015, 17,911,000 Ordinary Shares were issued (being the second tranche of new Ordinary Shares issued in July 2015) as part of a placing of new Ordinary Shares in the Company for an issue price of £0.38 per Ordinary Share.

3.1.8 On 11 July 2016, 19,334,000 Ordinary Shares were issued (being the first tranche of new Ordinary Shares issued in July 2016) as part of a placing of new Ordinary Shares in the Company for an issue price of £0.38 per Ordinary Share.

3.1.9 On 26 July 2016 and 27 July 2016, 60,501,682 Ordinary Shares were issued (being the second tranche of new Ordinary Shares issued in July 2016) as part of a placing of new Ordinary Shares in the Company for an issue price of £0.38 per Ordinary Share.

3.1.10 On 26 July 2016, 1,444,318 Ordinary Shares were issued to Andrew Knott and certain other members of the senior management team for an issue price of £0.38 per Ordinary Share.

3.1.11 On 28 December 2017, 27,462,000 Ordinary Shares were issued for an issue price of £0.35 per Ordinary Share.

3.1.12 On 9 February 2018, 514,885,980 Ordinary Shares were issued. Of this amount: (i) 239,000,000 Ordinary Shares were issued for an issue price of £0.35 per Ordinary Share; (ii) 224,021,689 Ordinary Shares were issued to the holders of the SSNs and 9,239,454 Ordinary Shares were deposited in trust in accordance with the terms of the Exchange Offer; and (iii) 42,624,837 Ordinary Shares were issued to the EBT.

3.1.13 On 26 June 2018, the English High Court confirmed the cancellation of the Company's share premium amount, which was effected by way of a special resolution of the Company dated 3 May 2018.

3.1.14 On 28 January 2019, 62,800,000 Ordinary Shares were issued for cash at an issue price of £0.28 per Ordinary Share.

3.1.15 On 14 November 2019, 116,638,985 Ordinary Shares were issued as part of the Transaction completion process.

3.2 The Company's issued fully paid share capital as at the date of this document is, and on Re-Admission will be, as follows:

	Present		*Immediately following Re-Admission*	
	Number	*Nominal Value*	*Number*	*Nominal Value*
Issued and fully paid	996,408,412	£996,408.412	996,408,412	£996,408.412

3.3 The Ordinary Shares in issue on Re-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 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 6).

3.4 The Ordinary Shares are denominated in Pounds Sterling.

3.5 The Company does not have in issue any equity securities not representing share capital.

3.6 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.

3.7 The International Security Identification Number for the Ordinary Shares is GB00BP41S218.

3.8 Save as disclosed in this paragraph 3 and paragraph 4 below:

3.8.1 there are no convertible securities, exchangeable securities or securities with warrants;

3.8.2 no person has any acquisition rights and or obligations over authorised but unissued capital, and there is no undertaking to increase the capital; and

3.8.3 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 the Long Term Incentive Plan;

4.1.2 the Supplementary Plan; and

4.1.3 the additional share option plan ("**Additional Share Scheme**").

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:

$X = A- ((AxB)/C)$

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) 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.

4.3 **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 the LTIP and the Supplementary Plan from time to time shall not exceed ten 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 £1.14 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 ceased 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 **Additional Share Scheme**

4.4.1 ***Introduction***

(a) On 15 June 2018, the Company established a new employee share option plan.

(b) The Additional Share Scheme is a discretionary share plan which will be administered by the Board or a committee appointed by the Board.

(c) Any employee (including an executive director) of the Company or any of its subsidiaries will be eligible to participate in the Additional Share Scheme at the discretion of the Board.

(d) Awards shall be granted in the form of options to acquire Ordinary Shares. Before Ordinary Shares are allotted pursuant to the exercise of any awards, the Board may decide to pay a cash amount equal to the value of the Ordinary Shares that the participant would otherwise have recorded, less the aggregate exercise price payable (the "**gain**"). Alternatively, the Board may deliver to the participant for nil or nominal value a number of Ordinary Shares with a value equal to the gain.

(e) Awards may be granted over pre-existing Ordinary Shares held by the EBT.

(f) The extent to which an award shall vest shall be determined by the Board by reference to a performance condition measuring the Company's total shareholder return ("**TSR**"). For the purposes of this performance condition, TSR shall be calculated as the VWAP of the Ordinary Shares over any period of 30 continuous dealing days within a period of five years from the relevant date of grant, plus the aggregate value of any dividends paid by the Company per Ordinary Share during such period. A performance condition may be amended or substituted if an event occurs which causes the Board to consider that an amendment/substitution would be appropriate and would not be materially less difficult to satisfy.

(g) Awards which are subject to performance conditions will normally vest as soon as practicable after the performance condition has been satisfied. Awards will normally be exercisable from the date of vesting until the tenth anniversary of the grant date.

(h) Various provisions will apply to the awards as set out below in the event of serious misconduct on the part of the participant where such conduct would justify their summary dismissal. At any time up to the date of vesting of an award, the Board may cancel the award or impose further conditions on it if the event described above occurs.

4.4.2 ***Ceasing to provide services to the Group: unvested awards***

(a) If a participant in the Additional Share Scheme ceases employment by reason of death, ill-health, injury, disability or for any other reason at the Board's discretion (a "**Good Leaver**"), any unvested award he holds will usually continue and vest at the normal vesting date. The Board will have discretion to vest the award at cessation of employment. If a participant in the Employee Plan ceases employment and is not a Good Leaver, he will be a "**Bad Leaver**" and his award will lapse.

(b) The extent to which an award held by a Good Leaver vests will be determined by reference to the extent to which any performance condition has been satisfied (as determined by the Board in the event of vesting before the end of the performance period). Unless the Board determines otherwise, the extent to which an award vests will be reduced to take account of the proportion of the vesting period that has elapsed at the date of cessation of employment.

4.4.3 ***Corporate events***

(a) In the event of a change of control of the Company, unvested awards will vest as soon as practicable, to the extent determined by the Board having regard to the extent to which any performance condition has been satisfied at the date of change of control (as determined by the Board) and/or such other factors as the Board considers appropriate. The Board may also take into account the extent to which the vesting period has elapsed in determining the extent of vesting.

(b) If other events occur, such as a winding up of the Company, demerger, delisting, special dividend or other event which, in the opinion of the Board, may affect the current or future value of Ordinary Shares, the Board may determine that awards will vest on the same basis as in the event of a change of control.

4.4.4 ***Adjustment of Awards***

In the event of a variation of the Company's share capital or a demerger, delisting, special dividend, rights issue or other event, which may, in the Board's opinion, affect the current or future value of Ordinary Shares, the number of Ordinary Shares subject to an award and/or the exercise price and/or any performance condition attached to awards, may be adjusted.

4.4.5 ***Amending the Additional Share Scheme, termination of the Additional Share Scheme and further terms of awards***

(a) The Board may amend the Additional Share Scheme at any time, provided that the approval of the Company's Shareholders in a general meeting will be required for any amendments to the advantage of participants relating to eligibility, limits, the basis for determining a participant's entitlement to, and the terms of, the Ordinary Shares comprised in an award and the impact of any variation of capital to become effective.

(b) However, any minor amendment to benefit administration, to take into account legislative changes, or to obtain or maintain favourable tax treatment, exchange control or regulatory treatment may be made by the Board without Shareholder approval.

(c) The Additional Share Scheme will in normal circumstances terminate on its tenth anniversary, but the rights of existing participants will not be affected by any termination.

4.5 **Awards**

4.5.1 As at the date of this document, 42,624,837 Ordinary Shares are held in the EBT.

4.5.2 As at the date of this document, the following awards (under the LTIP and the Supplementary Plan) have been granted over: (i) 15,464,013 ordinary shares in the capital of SP1L; and (ii) 9,999,874 Ordinary Shares (equal to approximately 1 per cent. of the existing Ordinary Shares. No awards have so far been granted under the Additional Share Scheme.

	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 Managers		
Yacine Wafy	547,765	257,450
Jessica Ross	273,883	531,332
Total	15,464,013	9,999,874

4.5.3 The Company intends, immediately following the publication of this document, to make the following awards under the Additional Share Scheme:

	Proposed share options to be granted under the Additional Share Scheme over Ordinary Shares held by the EBT
Directors	
Andrew Knott	21,312,418
Isatou Semega-Janneh	1,065,621
Senior Managers	
Yacine Wafy	1,065,621
Jessica Ross	1,065,621

4.5.4 The Company intends, immediately following the publication of this document, to make the following option awards to each of Sir Stephen O'Brien, David Clarkson and Michael Wachtel. Such awards are being made in full satisfaction of the Company's obligation to grant awards over new Ordinary Shares with an aggregate value of £50,000 (based on a price per Ordinary Share of £0.35) to each of them (see paragraph 7.2 of this Part 10 for further details). It is anticipated that the options will, *inter alia*, be granted over new Ordinary Shares, be exercisable for a period of five years and have an exercise price of £0.001 per Ordinary Share. There is no current intention to make the options subject to any vesting or other performance conditions.

	Proposed share options to be granted over new Ordinary Shares
Directors	
Sir Stephen O'Brien	142,857
David Clarkson	142,857
Michael Wachtel	142,857

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 dependent 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 he 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 which 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 18 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 of 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, all of which are legal and beneficial (except as noted below) in the issued share capital of the Company as at the Last Practicable Date are as follows:

Names	*As at the Last Practicable Date Ordinary Shares*	*%*
Directors		
Andrew Knott[8]	27,702,565	2.78
David Jamison[9]	651,009	0.07
Steve Jenkins	337,800	0.03
Mark Iannotti	3,066,887	0.31
Isatou Semega-Janneh	167,579	0.02
Sir Stephen O'Brien	–	–
Michael Wachtel	–	–
David Clarkson	357,000	0.04
Senior Managers		
Yacine Wafy[10]	762,555	0.08
Jessica Ross	74,776	0.01
Chris Thomas	–	–
Antoine Richard	–	–

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.

Other Interests of Directors in the Group

6.4 Andrew Knott owns legal and beneficial title to one ordinary share in the capital of each of LCP1 and Lothian Investment Partners Limited ("**LIP**"), comprising 100 per cent. of the issued share capital in each of LCP1 and LIP. LIP owns legal and beneficial title to one ordinary share in the capital of Ariadne Petroleum Limited, comprising 100 per cent. of the issued share capital in Ariadne Petroleum Limited. LCP1, LIP and Ariadne Petroleum Limited together own the legal and voting interest in 27,702,565 Ordinary Shares, being 2.78 per cent. of the Existing Ordinary Shares.

[8] Held through LCP1, Ariadne Petroleum Limited and LIP, all of which are 100 per cent. beneficially and legally owned by Andrew Knott.

[9] Held through Lowquest Limited, which is 100 per cent. beneficially and legally owned by David Jamison.

[10] Held through Rosambo Portfolio S.A., which is 100 per cent. beneficially and legally owned by Yacine Wafy.

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	Owlbrook LLP Scotia Oil & Gas LLP Osprey Petroleum Limited Wildcat Petroleum Limited GEP Castle Limited GEP Grey Owl Limited Franklin Petroleum Newfoundland Limited Savannah Petroleum 1 Limited Savannah Petroleum 2 Limited Savannah Petroleum International Limited Savannah Petroleum Services Limited Lothian Oil & Gas Partners LLP Djado Gold Limited	Lothian Investment Partners Limited Scotia Oil & Gas Exploration Limited Lothian Capital Partners 1 Limited Ariadne Petroleum Limited Golden Eagle Petroleum Limited Borealis Alaska Oil, Inc. Savannah Petroleum Niger S.A.
Isatou Semega-Janneh	N/A	Savannah Petroleum 1 Limited Savannah Petroleum International Limited Savannah Petroleum 2 Limited Savannah Petroleum Nigeria Midstream Limited Savannah Petroleum (Stubb Creek) Limited Savannah Petroleum (Uquo) Limited Savannah Petroleum Nigeria Limited Accugas UK Limited Accugas Holdings UK plc Exoro Holding B.V. Savannah Petroleum Niger S.A. Savannah Petroleum Technologies & Innovations Limited Savannah Petroleum (Uquo) Jersey Limited Seven Energy (BVI) Limited Stubb Creek Holdco Limited
David Lawrence Jamison	Angus Energy plc Mechcon International (Mechcon Ltd, Nigeria)	Lowquest Limited DJL Partners Limited Aquila Energy International Limited Energy Development and Investments UK Limited Jamison Family Property Management LLP
Stephen ("Steve") Ian Jenkins	Groliffe Limited Postgate Petroleum Limited Encounter Oil Limited	Circle Oil plc Hedgepig Growth Limited Oil & Gas Independents' Association Limited Terrain Energy Limited Talon Petroleum Limited Microenergy Generation Services Limited Evoterra Limited

Name	*Previous directorships/memberships*	*Current directorships/memberships*
Directors		
Marco ("Mark") Iannotti	Savannah Petroleum 1 Limited	Rocksteady Restaurant Enterprises Limited Galore Holdings Limited
Sir Stephen O'Brien	N/A	IVCC Observe Limited Motability Operations Group plc Department for International Trade Friends of the Global Fund Europe
David Clarkson	Bowleven plc Bowleven New Ventures Limited Bowleven (Kenya) Limited Bowleven Resources Limited Bowleven (Zambia) Limited FirstAfrica Oil Limited Bowleven Cameroon Limited Sound Energy plc	Adergy Limited
Michael Wachtel	N/A	Clyde & Co LLP
Senior Managers		
Jessica Kate Ross	N/A	Savannah Petroleum 1 Limited Savannah Petroleum International Limited Savannah Petroleum 2 Limited Savannah Petroleum Nigeria Midstream Limited Savannah Petroleum (Stubb Creek) Limited Savannah Petroleum Nigeria Limited Accugas UK Limited Accugas Holdings UK plc Savannah Petroleum (Uquo) Limited Exoro Holding B.V. Savannah Petroleum (Uquo) Jersey Limited Seven Energy (BVI) Limited Stubb Creek Holdco Limited
Chris Thomas	Old Brunswick Investments Limited Accugas UK Limited Savannah Petroleum (Uquo) Limited Accugas Holdings UK plc Stubb Creek Holdco Limited Exoro Holding B.V.	Seven Energy (UK) Limited Old Brunswick Resources Limited Seven Energy Finance Limited Seven Energy International Limited
Antoine Richard	N/A	N/A
Yacine Wafy	N/A	Primo et Geb S.A.R.L. Niger Exploration Limited Niger Exploration 1 Limited Savannah Petroleum Niger S.A.

6.6 Subject to paragraphs 6.7 and 6.8, 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. Steve Jenkins was a director of Postgate Petroleum Limited which was subject to a members' voluntary winding up on 28 August 2019.

6.8 Chris Thomas was a director of Renova Energy plc which filed for administration on 4 November 2008, and was dissolved via compulsory strike-off on 4 February 2010. Prior to this, the company's US subsidiary voluntarily filed for Chapter 11 bankruptcy protection in June 2008 as part of a financial restructuring process. Chris Thomas is a director of Seven Energy International Limited which was placed into administration on 13 November 2019 as part of the Transaction.

6.9 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:

6.9.1 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 Aberdeen plc	89,869,967	9.02%
TT International Asset Management	89,697,666	9.00%
Miton Asset Management Limited	85,524,292	8.58%
JO Hambro Capital Management	74,360,820	7.46%
Capital Group Companies, Inc.	59,840,179	6.01%
VR Global Partners, L.P.	57,340,868	5.75%
Cavendish Fiduciary Jersey Limited	51,864,291	5.21%
Ashmore Investment Management Limited	36,708,280	3.68%
Legal & General Investment Management Limited	29,965,689	3.01%

6.10 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.

6.11 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.

6.12 None of the Company's major holders of Ordinary Shares listed in paragraph 6.9 has voting rights which are different from other holders of Ordinary Shares.

6.13 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.

6.14 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.

6.15 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' SERVICE CONTRACTS AND REMUNERATION

The services of the Directors 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 28 February 2021. Under the terms of the agreement, Mr Knott is entitled to an annual salary of £525,000, 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 ten 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. Her service agreement shall continue until terminated on six months' written notice. Under the terms of the agreement, Isatou Semega-Janneh is entitled to an annual salary of £250,000, which is payable on a monthly basis and, at the sole discretion of the Company's remuneration and nomination committee, a bonus of up to 100 per cent. of her annual salary. Isatou Semega-Janneh is also eligible to participate in any management incentive programme that the Group may adopt. Her 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 ***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 £175,000 payable monthly.

7.2.2 ***Sir Stephen O'Brien***

On 21 December 2017, Sir Stephen O'Brien was appointed as non-executive vice chairman. The appointment shall continue until terminated by either the Company or Sir Stephen O'Brien on three months' written notice. Sir Stephen O'Brien is paid an annual fee of £60,000 payable monthly, and is entitled to a grant of awards over new Ordinary Shares with an aggregate value of £50,000 (based on a price per Ordinary Share of £0.35). Please see paragraph 4.5.4 of this Part 10 for further details of such awards.

7.2.3 ***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 £60,000 payable monthly, and is entitled to a grant of awards over new Ordinary Shares with an aggregate value of £50,000 (based on a price per Ordinary Share of £0.35). Please see paragraph 4.5.4 of this Part 10 for further details of such awards.

7.2.4 ***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 £60,000 payable monthly.

7.2.5 ***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 £60,000 payable monthly.

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 36 months' written notice. Mr Wachtel is paid a base annual fee of £60,000 payable monthly, and is entitled to a grant of awards over new Ordinary Shares with an aggregate value of £50,000 (based on a price per Ordinary Share of £0.35). Please see paragraph 4.5.4 of this Part 10 for further details of such awards.

7.3 **Directors' Appointment Details**

Name	*Date of Appointment*	*Date of Expiration of Current Term of Office*
Andrew Knott	3 July 2014	2021 AGM
Mark Iannotti	3 July 2014	2021 AGM
David Jamison	26 July 2014	2021 AGM
Steve Jenkins	26 July 2014	2021 AGM
Isatou Semega-Janneh	21 December 2017	2021 AGM
Sir Stephen O'Brien	21 December 2017	2021 AGM
David Clarkson	21 December 2017	2021 AGM
Michael Wachtel	21 December 2017	2021 AGM

8. EMPLOYEES

8.1 As at 31 December 2019, the Savannah Group had 169 employees and, as at the date of this document, the Savannah Group has 210 employees.

Location	*Number of Employees*
United Kingdom	28
Niger	14
Nigeria	168

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 entered into in connection with the Transaction are summarised in Part 11 of this document.

9.2 **Material contracts entered into by the Existing Group**

9.2.1 ***Financial adviser appointments***

(a) On 4 April 2019, the Company appointed Jefferies International Limited as its Joint Corporate Broker. The Company agreed to pay Jefferies International Limited an annual retainer fee in respect of its services. Jefferies International Limited no longer acts as Joint Corporate Broker.

(b) On 11 September 2019, the Company appointed Numis Securities Limited as its Joint Corporate Broker. The Company has agreed to pay Numis Securities Limited an annual retainer fee in respect of its services.

9.2.2 ***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**"). 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.

9.2.3 ***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 (US$34,000,000) and their advisers (US$2,720,000). The minimum work programme, as amended, required: (i) the acquisition of 500 km^2 3D seismic; and (ii) drilling two wells to a minimum depth of 2,500 m during the initial period of the exclusive exploration authorisation.

As at the date of this document, the initial term of the Exclusive Exploration Authorisation on the R1/R2 PSC has expired and the Company has agreed with the Ministry of Energy and Petroleum that a new PSC will be issued to Savannah Niger and that the R4 area of the R3/R4 PSC will be combined with the R1/R2 PSC Area into a new R1/R2/R4 PSC to be issued under the Petroleum Code 2017.

A summary of the key terms of the R1/R2 PSC is set out in Appendix C of this document.

9.2.4 ***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 Exclusive Exploration Authorisation on the R3/R4 PSC was renewed with respect to the R3 East portion of the R3/R4 PSC for a further two year term expiring 31 August 2021. The Company has agreed with the Ministry of Energy and Petroleum that the R4 area, which was relinquished at the end of the initial Exclusive Exploration Authorisation in accordance with the terms of the R3/R4 PSC, will be combined with the R1/R2 PSC Area into a new R1/R2/R4 PSC to be issued under the Petroleum Code 2017. The minimum work programme with respect to this first renewal period under the R3/R4 PSC requires: (i) the acquisition, processing and interpretation of 250 km^2 of new 3D seismic profiles; and (ii) the drilling of one exploration well to a minimum depth of 2,500 m.

A summary of the key terms of the R3/R4 PSC is set out in Appendix C of this document.

9.2.5 ***Proposed R1/R2/R4 PSC***

(a) The Company has been in discussions with the Government of Niger with respect to the terms of the proposed R1/R2/R4 PSC. The form of the proposed R1/R2/R4 PSC is subject to approval by the Council of Ministers and will be formally awarded to Savannah Niger on payment of the signature bonus. The Directors expect that Council of Ministers approval will be forthcoming shortly after publication of this document.

(b) A summary of the key terms of the proposed R1/R2/R4 PSC is set out in Appendix C of this document.

9.2.6 ***Admission Agreement***

On 30 April 2020, the Company, the Directors and Strand Hanson entered into an admission agreement in relation to Re-Admission. The Company has given certain representations, warranties, undertakings and indemnities to Strand Hanson and the liability of the Company under the admission agreement is unlimited as to amount and time.

9.2.7 ***Lock In Agreements***

The Company, Strand Hanson, each of the Directors and certain Senior Managers holding Ordinary Shares entered into lock-in agreements on 30 April 2020 whereby each of the Directors and members of Senior Management holding Ordinary Shares have agreed not, without the prior written consent of Strand Hanson (acting in their absolute discretion), to dispose of any part of their interests in Ordinary Shares held by them or their associates at Re-Admission for the period of 12 months from Re-Admission.

9.2.8 ***Placing Agreements***

(a) On 22 December 2017, the Company, the Directors, Barclays Bank PLC, Strand Hanson, Mirabaud, Hannam & Partners and Shore Capital entered into a placing agreement in relation to the placing by the Company of 266,462,000 Ordinary Shares at a price of £0.35 per Ordinary Share. The Company has given certain representations, warranties, undertakings and indemnities to Barclays Bank PLC, Strand Hanson, Mirabaud, Hannam & Partners and Shore Capital and the liability of the Company under the placing agreement is unlimited as to amount and time.

(b) On 24 January 2019, the Company, the Directors, Strand Hanson, Mirabaud, Hannam & Partners and Shore Capital entered into a placing agreement in relation to the placing by the Company of 62,800,000 Ordinary Shares at a price of £0.28 per Ordinary Share. The Company has given certain representations, warranties, undertakings and indemnities to Strand Hanson, Mirabaud, Hannam & Partners and Shore Capital and the liability of the Company under the placing agreement is unlimited as to amount and time.

9.2.9 ***Signature of MoU with the Republic of Niger***

On 8 August 2018, Savannah Niger entered into a legally binding memorandum of understanding with the Republic of Niger. The memorandum of understanding affirms both Parties' commitment to the realisation of a proposed early production scheme ("**EPS**") utilising crude oil resources associated with the Group's discoveries in the R3 portion of the R3/R4 Production Sharing Contract area in the Agadem Rift Basin ("**ARB**") of South East Niger. The MOU further binds both parties to work together towards the realisation of the EPS and contains specific provisions relating to the actions each Party undertakes to conduct as well as setting out the key timelines associated with the project.

9.2.10 ***Loan facilities***

(a) 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 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.

(b) On 18 October 2019, the Company entered into a new US$10,000,000 unsecured loan agreement. The facility is provided by funds managed by Riverfort Global Capital Ltd and Yorkville Advisors Global, LP. Of the US$10,000,000 facility, US$3,350,000 is currently outstanding and is repayable on 6 June 2020, and US$5,000,000 can be drawn down by the Company within a two year period with the agreement of the facility provider. A fixed interest premium of seven per cent. is payable at maturity.

(c) On 30 April 2020, the Company entered into a US$15 million finance agreement with Vision Energy LTD. The finance is available for use in connection with the Group's general corporate and working capital purposes. A redemption fee of eight per cent. per annum accrues on any amounts of the finance drawn down from time to time on a straight line basis and is payable on the date any amount of the finance is repaid. The finance agreement also provides for an arrangement fee of US$750,000 to be payable on the final repayment date under the finance agreement, being the earlier of the date falling: (i) 18 months after the date the finance agreement was entered into; or (ii) 15 business days after a qualifying debt or equity fundraising by the Company raising more than US$5 million. The Company's ability to draw down on the finance is dependent on Andrew Knott being CEO of the Company at that time, though any departure of Andrew Knott does not trigger immediate repayment of drawn amounts.

9.2.11 ***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.

9.2.12 ***Warrant Instrument***

On 21 December 2017, the Company entered into a warrant instrument pursuant to which it issued 133,231,000 warrants each entitling the holder thereof to subscribe for Ordinary Shares at £0.35 payable in cash in full on exercise. No warrants were exercised prior to the expiry date of 11 February 2019 and all the warrants have now lapsed in accordance with the terms of the warrant instrument.

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 Part 11 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

Save as disclosed in this document, 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. The Company also has establishments in: (i) Lagos, Nigeria; (ii) Uyo, Nigeria; (iii) Eket, Nigeria; (iv) Abuja, Nigeria; (v) Niamey, Niger; (vi) St Helier, Jersey; and (vii) Paris, France.

13. WORKING CAPITAL

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

In making the above working capital statement, the Directors, as required by the ESMA Recommendations, are required to assess whether there is sufficient margin or headroom to cover a reasonable worst case scenario.

COVID-19 has resulted in significantly increased levels of uncertainty for many companies, with a wide range of possible financial impacts, resulting in challenges to COVID-19-impacted businesses in producing sufficiently reliable forecasts of their future financial performance to determine the reasonable worst case scenario.

For purposes of this working capital statement, the Company has formed its view of a reasonable worst case scenario using the following COVID-19-specific assumptions, which the working capital statement is therefore dependent upon:

- force majeure clauses under the downstream GSAs with the Calabar, Ibom Power and Unicem are not successfully invoked as a result of the COVID-19 situation; and
- the price of Brent crude, which has been significantly impacted by the COVID-19 outbreak, does not fall below $23.70 per barrel for a sustained period.

The working capital statement in this Admission Document has been prepared in accordance with the ESMA Recommendations and the technical supplement to the FCA Statement of Policy published on 8 April 2020 relating to the COVID-19 crisis.

14. LITIGATION

14.1 Subject to paragraph 14.2, no member of the 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 The Company and, inter alia, members of the Enlarged Group have been named in a suit brought by an indirect shareholder in SEIL in the High Court in Nigeria seeking interlocutory relief in respect of the

Acquisition. The Directors, having taken legal advice, believe the case lacks merit and is defending its position.

15. COVID-19 RELATED CLAIMS

The Enlarged Group has received notices from two of its gas offtakers, Unicem and Ibom Power, claiming force majeure on the basis of the COVID-19 pandemic. Neither counterparty has provided the requisite information to substantiate its claim and therefore, having taken initial legal advice from external counsel, the Enlarged Group is refusing to recognise these force majeure claims.

16. NO SIGNIFICANT CHANGE STATEMENT

16.1 Save as disclosed in this document, there has been no significant change in the trading or financial position of the Existing Group since 30 June 2019, the date to which the last interim accounts of the Existing Group were published.

16.2 Save as disclosed in this document, there has been no significant change in the trading or financial position of the Target Companies since 30 June 2019, the date to which the unaudited interim historical financial information of the Target Companies included in this document was prepared.

17. GENERAL

17.1 The total costs and expenses of, or incidental to, Re-Admission, all of which are payable by the Company, are estimated to be approximately US$2.6 million (exclusive of value added tax).

17.2 The Competent Person's reports in respect of the Nigerien and Nigerian assets are included, in the form and context in which they are included, with the consent of CGG Services (UK) Limited which has authorised the contents of its reports for the purposes of the AIM Rules. CGG Services (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.

17.3 BDO LLP, Chartered Accountants and Registered Auditors, of 55 Baker Street, London, W1U 7EU, has given and has not withdrawn its consent to the inclusion of its Accountant's Report on the historical financial information of the Target Companies in Part 6A 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.

17.4 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.

17.5 Save as disclosed in of this document, the Directors are unaware of any exceptional factors which have influenced the Group's activities.

17.6 Save as set out in paragraph 17.7 of this Part 10 and as otherwise 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 Re-Admission any fees, securities in the Company or any other benefit to the value of £10,000 or more.

17.7 In connection with the Transaction, VR Global Partners, L.P. ("**VR**") received 3,273,152 new Ordinary Shares in full satisfaction of an underwriting fee of US$1 million due to VR under the terms of an underwriting agreement entered into between, inter alia, VR and the Company dated 5 February 2018, as amended and restated on 1 February 2019 and as further amended and restated on 6 February 2019.

17.8 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.

17.9 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.

17.10 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.

17.11 There are no provisions in the Articles which would have the effect of delaying, deferring or preventing a change of control of the Company.

17.12 Save as disclosed in this document, the Directors are unaware of:

17.12.1 any significant trends in production, sales and inventory and costs and selling prices since 31 December 2018 to the date of this document; and

17.12.2 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.

17.13 The Articles contain no restriction on the objects of the Company.

18. UK TAXATION

18.1 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 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, such as persons owning shares as securities to be realised in the course of a trade, persons owning more than a ten 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.

Certain Shareholders, such as dealers in securities, collective investment schemes, insurance companies and persons acquiring their Ordinary Shares 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 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 Ordinary Shares.

18.2 Dividends

Dividends received from the Company by a UK tax 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 £2,000 of taxable dividend income received by the shareholder in a tax year. Where the dividend income is above the £2,000 dividend allowance, the first £2,000 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.

UK tax resident corporate shareholders will not generally be subject to tax on dividends received by the Company as long as the dividends fall 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 ten per cent. of the issued share capital of the payer.

Non-UK tax 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.

18.3 **Capital Gains**

A disposal of Ordinary Shares by a Shareholder resident or, in the case of an individual, resident for UK tax purposes in the United Kingdom may, depending on the Shareholder'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.

A disposal of Ordinary Shares by a Shareholder who is resident in the United Kingdom for United Kingdom tax purposes or who is not UK tax 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 circumstances and subject to any available exemption or relief.

In the absence of any available allowances and reliefs, a gain arising on the disposal of Ordinary Shares by a UK tax resident Individual Shareholder will be taxed at a rate of ten 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 (£50,000 for the tax year ending 5 April 2020), in which case it will be taxed at the rate of 20 per cent. The capital gains tax annual exemption (£12,300 for the tax year ending 5 April 2021) may be available to an individual shareholder to offset against chargeable gains realised on the disposal of Ordinary Shares. Please note the receipt of carried interest gains and gains arising on the disposal of UK residential property can be taxed at 18 per cent. and 28 per cent. instead of ten per cent. and twenty per cent.

For a Shareholder which is a UK tax resident company, any gain on the disposal of its Ordinary Shares will be subject to corporation tax (19 per cent. for the tax year ending 31 March 2021) 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 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 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.

18.4 **Stamp duty and stamp duty reserve tax**

No UK 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 Company remains listed on AIM, the Ordinary Shares are admitted to trading on AIM but not listed on any other market, and AIM continues to be a recognized growth market for the purpose of the Finance Act 2014, subsequent dealings in Ordinary Shares should not be subject to

UK ad valorem stamp duty or SDRT. Otherwise, transfers of Ordinary Shares for value will generally give rise to a liability for the buyer 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). An exemption from UK ad valorem stamp duty will be available provided that the amount or value of the consideration is less than £1,000, and the instrument contains a certificate that the current transfer does not form part of a larger transaction or series of transactions where the total would exceed £1,000.

Special provisions may apply to transfers of Ordinary Shares to depositary receipts regimes, clearance services and market intermediaries.

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. If any Shareholder is unsure about their tax position, they should obtain professional tax advice.

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

19.1 **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 per cent. 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.

19.2 **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 ten 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.

19.3 **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.

20. 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:

20.1 the memorandum and articles of association of the Company; and

20.2 the Accountant's Report on the Historical Annual Financial Information of the Target Companies from BDO LLP set out in Part 6A of this document.

21. 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-energy.com.

PART 11

MATERIAL CONTRACTS

1. MATERIAL CONTRACTS RELATING TO THE TRANSACTION

1.1 *Accugas Term Facility*

1.1.1 On 23 June 2015, Accugas Limited entered into a term facility agreement between, amongst others, certain financial institutions as lenders and FBNQuest Capital Limited as facility agent (the "**Facility Agent**") (as amended pursuant to an amendment agreement dated 1 August 2019 between, amongst others, Accugas Limited and the Facility Agent) (the "**Existing Term Facility**").

1.1.2 The Existing Term Facility was further amended and restated (the "**Amended and Restated Term Facility**") pursuant to an amendment and restatement agreement dated 7 November 2019 between, amongst others, Accugas Limited and the Facility Agent entered into in connection with the Transaction (the "**Amendment and Restatement Agreement**"). The Amended and Restated Term Facility is a US$382.1 million term facility with a maturity date of 31 December 2025 and interest rate of USD LIBOR + 10.43 per cent. The Amended and Restated Term Facility is secured against the assets and the shares of Accugas Limited.

1.1.3 The Amended and Restated Term Facility has fixed semi-annual amortisation payments (30 June and 31 December of each year) with a cash sweep semi-annually applied against principal, together with historic and forecast debt service cover ratios and forecast interest cover ratio financial covenants and restrictions on the repayment of shareholder loans and dividends until the facility is fully repaid.

1.1.4 On 23 June 2015, Accugas Limited entered into an accounts bank agreement between, amongst others, Accugas Limited, the Facility Agent and certain account banks (the "**Existing Accounts Bank Agreement**"). The Existing Accounts Bank Agreement has been further amended and restated pursuant to the Amendment and Restatement Agreement (the "**Amended and Restated Accounts Bank Agreement**"). The Amended and Restated Accounts Bank Agreement governs the account arrangements of Accugas Limited, including in relation to withdrawals from, lock-up and set-off of accounts, the waterfall of payments from the collection accounts and arrangements in respect of the gas prepayment accounts.

1.2 *Working Capital Facility*

1.2.1 On 2 October 2015, SUGL, Seven Energy (BVI) Limited, Seven Energy (Jersey) Limited, Seven Energy Ltd. and Seven Exploration and Production Limited entered into a working capital facility agreement with, amongst others, the Facility Agent (the "**Existing Working Capital Facility**").

1.2.2 The Existing Working Capital Facility has been amended and restated pursuant to the Amendment and Restatement Agreement (the "**Amended and Restated Working Capital Facility**"). The Amended and Restated Working Capital Facility is between SUGL as borrower and FBNQuest Merchant Bank Limited as original lender and is a NGN 4.8 billion (approx. US$13.3 million) term facility with a maturity date of 31 December 2026 and interest rate of NIBOR + five per cent. The Amended and Restated Working Capital Facility is secured against the shares of Savannah Petroleum Nigeria Limited's subsidiaries as well as the assets of Savannah Petroleum Nigeria Limited and its subsidiaries, including the interests the Group owns in the Uquo Field and the Stubb Creek Field, and benefits from guarantees from Savannah Petroleum Nigeria Limited and its subsidiaries. Such security and guarantees rank *pari passu* with those granted in favour of the SUGL Notes (as defined below).

1.2.3 All amounts borrowed under the Amended and Restated Working Capital Facility have been applied towards SUGL's general corporate and working capital purposes. The Amended and Restated Working Capital Facility amortises semi-annually (31 December and 30 June).

1.3 ***Promissory Note***

1.3.1 On 21 July 2015, Seven Energy Finance Limited as outgoing payor (the "**Outgoing Payor**") and FBNQuest Capital Limited as the payee (the "**Payee**") entered into a deed of novation and variation in relation to a US$12,000,000 promissory note originally issued by Seven Energy International Limited to the benefit of GEC Petroleum Development Company Limited on 12 December 2014 and which was subsequently novated on 12 December 2014, such that the Payee was the payee thereunder and the Outgoing Payor was the payor thereunder (the "**Original Promissory Note**").

1.3.2 The Original Promissory Note was novated and amended pursuant to a deed of novation and amendment dated 6 November 2019 between the Outgoing Payor, Accugas HoldCo, as payor (the "**Payor**"), the Payee and Accugas MidCo, as guarantor, entered into in connection with the Transaction (the "**Amended and Restated Promissory Note**"). The Amended and Restated Promissory Note is a US$11.5 million promissory note with a maturity date of 31 December 2025, cash interest rate of eight per cent. and an ability for the Payor to elect to pay PIK interest rather than cash interest at a PIK interest rate of ten per cent.

1.3.3 The Promissory Note is secured against the shares of Accugas HoldCo, Accugas MidCo and Exoro as well as the assets of Accugas HoldCo and Accugas MidCo, but not (for the avoidance of doubt) against the shares or assets of Accugas Limited. The Payee also benefits from a guarantee from Accugas MidCo. Such security and guarantees rank *pari passu* with those granted in favour of the Accugas HoldCo Senior Secured Notes and the Reinstated First Bilateral Facility (each as defined below).

1.3.4 The Promissory Note is additionally secured against the shares of Savannah Petroleum Nigeria Limited's subsidiaries as well as the assets of Savannah Petroleum Nigeria Limited and its subsidiaries, including the interests the Enlarged Group owns in the Uquo Field and the Stubb Creek Field, although such security ranks behind that granted in favour of the SUGL Notes (as defined below) and the Amended and Restated Working Capital Facility.

1.3.5 The Payee also benefits from guarantees from Savannah Petroleum Nigeria Limited and its subsidiaries from the date on which the SUGL Notes and the Amended and Restated Working Capital Facility are discharged.

1.3.6 The Promissory Note amortises semi-annually with repayment instalments of US$500,000 commencing on 30 June 2021.

1.4 ***Accugas HoldCo Senior Secured Notes***

1.4.1 Pursuant to the terms of the Lock-up Agreement, holders of the SSNs who elected to subscribe for the SSN Shares were also entitled to a *pro rata* share of the US$20 million senior secured notes with a maturity date of 15 November 2025 (the "**Accugas HoldCo Senior Secured Notes**") that were issued by Accugas HoldCo to certain SSN holders and underwriters upon completion of the Transaction.

1.4.2 Cash interest on the Accugas HoldCo Senior Secured Notes accrues on a pay-if-you-can basis at six per cent. per annum and paid-in-kind interest accrues at eight per cent. per annum. The Accugas HoldCo Senior Secured Notes are secured against the shares of Accugas HoldCo, Accugas MidCo and Exoro as well as the assets of Accugas HoldCo and Accugas MidCo, but not (for the avoidance of doubt) against the shares or assets of Accugas Limited. The Accugas HoldCo Senior Secured Notes also benefit from a guarantee from Accugas MidCo. Such security and guarantees rank pari passu with those granted in favour of the Promissory Note and the Reinstated First Bilateral Facility (as defined below).

1.5 ***SUGL Notes***

1.5.1 Pursuant to the terms of the Implementation Agreement, upon completion of the Transaction SUGL issued US$105 million of notes with a maturity date of 31 December 2026 (the "**SUGL Notes**") (payable in NGN at the prevailing NAFEX rate) to the holder of SEFL's 10.50 per cent. Senior Secured Notes due 2021.

1.5.2 The SUGL Notes have an annual amortisation profile of US$8.4 million, paid semi-annually, and a bullet at final maturity. Interest is payable in cash only and accrues at eight per cent. per annum. The SUGL Notes are secured against the shares of Savannah Petroleum Nigeria Limited's subsidiaries as well as the assets of Savannah Petroleum Nigeria Limited and its subsidiaries, including the interests the group owns in the Uquo Field and the Stubb Creek Field, and benefit from guarantees from Savannah Petroleum Nigeria Limited and its subsidiaries. Such security and guarantees rank *pari passu* with those granted in favour of the Amended and Restated Working Capital Facility.

1.6 ***Liquidity Facility Agreement***

1.6.1 On 14 November 2017, the Company as lender entered into a super senior secured revolving credit facility (as amended and/or restated from time to time, the "**Liquidity Facility**") with, inter alios, SEIL and SUGL as borrowers in order to provide the Seven Group with additional finance for general corporate and working capital requirements in connection with the Transaction.

1.6.2 Pursuant to the terms of the Liquidity Facility, prior to completion of the Transaction the Company made certain loans available to SEIL, the outstanding aggregate principal amount (including capitalised interest) of which as at completion of the Transaction was US$34,963,035.46 (the "**Outstanding Amount**").

1.6.3 As part of completion of the Transaction on 14 November 2019, SEIL's outstanding obligations to the Company under the Liquidity Facility, consisting of the Outstanding Amount, were assumed by Eight Holdco and an advance in an aggregate principal amount equal to the Outstanding Amount (the "**Advance**") was deemed to be made by the Company to Eight Holdco pursuant to the amendment and restatement of the Liquidity Facility as an unsecured subordinated shareholder loan within the Company's group.

1.6.4 The rate of interest on the Advance is six per cent. per annum which will be capitalised and added to the principal amount of the Advance bi-annually on each interest payment date, and the Advance is repayable (together with all accrued, including capitalised, interest) in full on demand. The Liquidity Facility is subject to the terms of the SUGL Intercreditor Agreement.

1.7 ***Reinstated First Bilateral Facility***

In connection with the Transaction, the existing US$24.1 million facility made available to SEFL and Seven Energy Ltd. was restructured such that US$20 million was reinstated at Accugas HoldCo (the "**Reinstated First Bilateral Facility**"), with a residual amount of $4.1 million remaining at SEFL and Seven Energy Ltd. The Reinstated First Bilateral Facility has a maturity date of 14 November 2025 with a cash interest rate of six per cent. and PIK interest rate of eight per cent. It is repaid in full on the maturity date. The Reinstated First Bilateral Facility is secured against the shares of Accugas HoldCo, Accugas MidCo and Exoro as well as the assets of Accugas HoldCo and Accugas MidCo, but not (for the avoidance of doubt) against the shares or assets of Accugas Limited. The Reinstated First Bilateral Facility also benefits from a guarantee from Accugas MidCo. Such security and guarantees rank pari passu with those granted in favour of the Promissory Note and the Accugas HoldCo Senior Secured Notes. Following completion of the Transaction, the Reinstated First Bilateral Facility was purchased by the Company as lender and was re-characterised as subordinated liabilities for the purposes of the Accugas HoldCo Intercreditor Agreement.

1.8 ***SEIL Sale and Purchase Agreement***

On 14 November 2019, as part of the Completion mechanics, SEIL (acting by its English and Mauritian administrators who also entered into the sale and purchase agreement in their own capacity), as vendor, entered into a sale and purchase agreement with Savannah Petroleum Nigeria Limited, Savannah Petroleum Nigeria Midstream Limited and SP1L as purchasers. The agreement effected the transfer to the Existing Group of SUGL and Accugas Limited (by virtue of the transfer of their holding companies) as well as certain contracts, miscellaneous assets and intellectual property. The total consideration payable by the Existing Group under the agreement was approximately US$141.4 million and consisted of approximately:

1.8.1 US$55,000 in cash;

1.8.2 a US$183,000 promissory note;

1.8.3 US$34.963 million in assumed debt; and

1.8.4 US$106.231 million in transferred SSNs.

1.9 ***SEPL Sale and Purchase Agreement***

On 14 November 2019, as part of the Completion mechanics, SEPL as vendor entered into a sale and purchase agreement with Savannah Petroleum Nigeria Limited, Accugas Limited, SUGL and Savannah Petroleum (Stubb Creek) Limited as purchasers. The agreement effected the transfer to the Existing Group of Universal and its minority shareholder Stubb Creek HoldCo Limited, as well as a single share in SUGL and certain contracts; certain contracts and miscellaneous assets were also transferred to SUGL, which had been transferred to the Existing Group pursuant to the SEIL sale and purchase agreement referred to in paragraph 1.8 above. The total consideration payable by the Existing Group under the agreement was approximately US$58.29 million and consisted of circa:

1.9.1 US$3,317,000 in promissory notes;

1.9.2 new Ordinary Shares with a value of US$9.2 million; and

1.9.3 US$45.769 million in transferred SSNs.

1.10 ***SEUK Sale and Purchase Agreement***

On 14 November 2019, as part of the Completion mechanics, Seven Energy (UK) Limited as vendor entered into a sale and purchase agreement with SP1L as purchaser. The agreement effected the transfer to SP1L of certain contracts and miscellaneous assets. The total consideration payable by the Group under the agreement was approximately US$0.01 million in cash.

2. MATERIAL CONTRACTS RELATING TO THE UQUO FIELD

2.1 ***Uquo HoldCo Shareholders' Agreement***

2.1.1 On 14 November 2019, African Upstream Holdings Mauritius ("**AIIM Uquo**"), Savannah Petroleum (Uquo) Jersey Limited ("**Uquo TopCo**") and Savannah Petroleum (Uquo) Limited ("**Uquo HoldCo**") entered into a shareholders' agreement relating to Uquo HoldCo (the "**Uquo SHA**").

2.1.2 There shall be no more than five directors on the board of Uquo Holdco. The Uquo TopCo shall have the right to appoint three directors and AIIM Uquo shall have the right to appoint two directors.

2.1.3 There shall be no more than five directors on the board of SUGL. Uquo TopCo shall have the right to appoint three directors of SUGL and AIIM Uquo shall have the right to appoint two directors of SUGL. The CEO shall be a director of SUGL (as a Uquo TopCo nominated director). Uquo Topco shall propose candidates for the role of chief executive officer of SUGL for approval by AIIM Uquo (acting reasonably). Uquo TopCo and AIIM Uquo shall give joint written notice to the board of SUGL to appoint the CEO.

2.1.4 The initial rolling five-year business plan and rolling annual budget has been approved by Uquo TopCo and AIIM Uquo. Each subsequent business plan and budget shall be prepared by the CEO and senior management of SUGL and submitted annually to the board of Uquo Holdco for approval. The board of Uquo HoldCo shall consult with, and reasonably consider the comments of, the shareholders.

2.1.5 Shareholders are not obliged to provide any capital to Uquo HoldCo by way of subscription for further shares or by way of a loan. Subject to the approval of the board of Uquo HoldCo and the terms of any third party financing agreements, Uquo HoldCo may request further funding from the shareholders. Each shareholder may provide to Uquo HoldCo its proportion of any additional funding in cash by way of a shareholder loan on certain agreed commercial terms (an "**Uquo Additional Shareholder Loan**"). If a shareholder elects not to provide an

Uquo Additional Shareholder Loan, the other shareholders may elect to provide all or part of the funding shortfall by providing an additional shareholder loan on certain agreed commercial terms (an "**Uquo Additional Shortfall Loan**"). If any employees join any employee share scheme of the Company or its affiliates, the corresponding amount of such employee share scheme shall be deemed an interest free shareholder loan between Uquo HoldCo and Uquo TopCo (an "**Uquo Employee Share Scheme Loan**").

2.1.6 Subject to: (i) the terms of any third party financing agreements; (ii) applicable law and insolvency legislation; (iii) maintaining a minimum US$10 million cash reserve; and (iv) making appropriate provision for working capital and liabilities of the group as the board of Uquo HoldCo deems appropriate; the board of Uquo HoldCo shall resolve (and procure that the group companies resolve) to distribute all distributable cash to the shareholders on a quarterly basis or as soon as possible after a capital event. Such distributable cash shall be allocated and distributed in the following priority: (i) repayment of interest and principal amounts outstanding under all Uquo Additional Shortfall Loans; (ii) repayment of interest and principal amounts outstanding under all Uquo Additional Shortfall Loans; (iii) repayment to Uquo TopCo of the amounts outstanding under all Uquo Employee Share Scheme Loans; and (iv) the remainder to the shareholders as a dividend *pro rata* the number of shares in Uquo HoldCo held at the time.

2.1.7 The following reserved matters (applicable to Uquo HoldCo, Seven Energy (BVI) Limited and SUGL) shall require an 85 per cent. majority vote of the shareholders:

(a) any change to the articles of Uquo Holdco, the business, the auditors, the distribution policy, the share capital or share rights;

(b) any material amendment to, or withdrawal or relinquishment from, the Uquo JOA;

(c) any transfer of SUGL's participating interest under the Uquo JOA;

(d) sale of any fixed assets with a value greater than US$20 million or which are a material part of the infrastructure of the Uquo business;

(e) change to the business plan and budget (other than due to inflation or the undertaking of a new revenue generating activity) that may result in an increase of the aggregate of total operating and administrative costs in a financial year by more than fifty per cent. when compared against the amount budgeted for that financial year;

(f) SUGL undertaking an Exploration Operation (described below);

(g) settlement of disputes with a value of over US$5 million or relating to the material assets;

(h) winding up, proposing any arrangement or composition with creditors of Uquo HoldCo, applying for an administration order or appointing a receiver or administrator in respect of Uquo HoldCo;

(i) any material transaction with a shareholder or any of its affiliates, or any guarantee or indemnity not in the ordinary course of business and on arm's length terms;

(j) any material amendment to the Uquo Services Agreement;

(k) mergers and acquisitions, or the entry into of any partnership, joint venture or consortium agreement not included in the business plan and budget;

(l) acquiring or disposing of any material undertaking of company or closing down any material business operation;

(m) any issue of share capital other than to a group company which is wholly owned by Uquo HoldCo; and

(n) sale of shares in Seven Energy (BVI) Limited or SUGL.

2.1.8 Save for a permitted transfer, shareholder consent is required for a shareholder to transfer any shares. Permitted transfers are:

(a) Where Uquo TopCo wishes to transfer all or part of its shares in Uquo HoldCo to a third party purchaser on arm's length terms, Uquo TopCo must procure that the third party purchaser, subject to certain conditions, makes a written offer to AIIM Uquo to purchase a *pro rata* amount of its shares in Uquo HoldCo.

(b) Where Uquo TopCo wishes to transfer all (but no part only) of its shares in Uquo HoldCo to a *bona fide* third party purchaser on arm's length terms, subject to certain conditions, Uquo TopCo shall have the option to require the other shareholders to sell their shares to the third party purchaser. If the proposed purchase price of the shares held by AIIM Uquo is less than the higher of: (i) 20 per cent. IRR on AIIM Uquo's total investment expenditure in Uquo HoldCo at such date; or (ii) 2.5 times AIIM Uquo's total investment expenditure in Uquo HoldCo at such date, AIIM Uquo has the right to decline to sell its shares in Uquo HoldCo. If AIIM Uquo declines the third party purchaser's offer, it shall no longer have the right to exercise the Uquo Exit Option (describer below).

(c) Save if the transferee is a restricted person, where a shareholder wishes to transfer to an affiliate.

(d) Where a shareholder wishes to sell all or part of its shareholding (the "**Uquo Sale Shares**") in Uquo Holdco the selling shareholder shall notify the other shareholders in writing of its intention to sell the Uquo Sale Shares, and each remaining shareholder may notify the selling shareholder in writing of the cash price (the "**Uquo Offer Price**") at which it would be willing to purchase the Uquo Sale Shares and the key terms of such purchase (the "**Uquo Offer Terms**"). If the selling shareholder does not accept any Uquo Offer Terms or Uquo 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 Uquo Offer Price and on materially the same terms as the Uquo Offer Terms. Where the proposed purchaser is a Uquo 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 Uquo TopCo considers, acting reasonably, would restrict or prevent Uquo TopCo or SUGL 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 Uquo Sale Shares for the same price and on the same terms as offered by such Uquo Matching-Right Transferee.

(e) Under the Uquo SHA, AIIM Uquo has a non-transferrable option to require Uquo TopCo to purchase all of AIIM Uquo's shares in Uquo HoldCo on any date falling within 30 calendar days of 14 November 2023 ("**Uquo Exit Option**"). The consideration for such shares (the "**Uquo Exit Consideration**") is to be calculated in accordance with an agreed Uquo Exit Consideration formulae at the date AIIM Uquo serves notice on Uquo TopCo to exercise its option. If prior to the date the Uquo Exit Option arises the Company is taken over by a third party, the Exit Consideration shall be calculated in accordance with the Uquo Exit Consideration formulae and capped at an amount equal to 18 per cent. IRR on AIIM Uquo's total investment expenditure at such date in Uquo HoldCo.

(f) Uquo Topco or any of the directors of SUGL nominated by Uquo TopCo may propose that it undertakes the acquisition or licensing of seismic data for exploration purposes and/or the drilling of any exploration well in accordance with the terms of the Uquo JOA ("**Exploration Operation**"). A decision to pursue an Exploration Operation is a shareholder reserved matter. If the shareholders elect not to approve the Exploration Operation, the Uquo TopCo or its affiliate shall have the right to pursue the unapproved Exploration Operation through an affiliate of SUGL under the Uquo JOA (a "**SUGL Exploration Affiliate**"). The shareholders shall procure that SUGL transfers the minimum percentage of its participating interest under the Uquo JOA to the relevant SUGL Exploration Associate as is necessary for the same to undertake the unapproved Exploration Operation as a sole risk operation in accordance with the Uquo JOA. The SUGL Exploration Affiliate shall bear the entire cost of the unapproved Exploration Operation sole risk operations, and be entitled to 100 per cent. of any hydrocarbons produced therefrom. If, during the unapproved Exploration Operations, a discovery of previously unproven hydrocarbons is made, subject to certain conditions (including the payment of a back-in premium amount), AIIM Uquo shall have the right to elect to back-in and participate in such Exploration Operations.

2.2 ***Uquo Field Farm-Out Agreement***

2.2.1 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 and the holders of OML 13 at this time, agreed to terms of a farm-out agreement under which the Uquo Field would be developed by Frontier (the "**Uquo FOA**"). As at the date of this document, Nigerian Petroleum Development Company ("**NPDC**"), a wholly owned subsidiary of NNPC, is the holder of OML 13 (i.e. the farmor). The term of the Uquo FOA was for an initial period of sixty months and subsequently renewed. As at the date of this document, the DPR has requested a licence renewal fee of US$1 million for a ten year renewal of the Uquo FOA until 2026. The requested renewal fee has not yet been paid by Frontier. The Company intends to pay any renewal fees that are ultimately found to be due.

2.2.2 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**"). This assignment was approved by the MPR on 4 October 2006. Red Rock then assigned the interest to SUGL, itself an affiliate of Red Rock. This assignment was approved by the MPR on 3 October 2007.

2.2.3 The Uquo FOA requires Frontier to pay to the Uquo FOA farmor 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. 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 document, daily production of natural gas from the Gas Project has exceeded 20 MMscfpd, but no agreement has been made between the parties as to the level of the overriding royalty rate. The farmor can lift its crude oil entitlement from the field or elect to receive its 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.

2.2.4 Under the Uquo FOA if Frontier owes money to the farmor for a continuous period of three months, Frontier will be in default. If Frontier is deemed to be in default it is deemed to have granted to the farmor 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 farmor. The farmor is entitled to sell the production and, after deducting all costs incurred during the sale, is entitled to recover from the remaining proceeds all amounts owed to the farmor by Frontier.

2.2.5 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 FOA farmor can also terminate on

30 days' notice if Frontier ceases operations for more than 90 days without acceptable cause or justification.

2.2.6 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 farmor were required to enter into an abandonment security agreement. As at the date of this document, 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.

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 amounts 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 ***Uquo Field Joint Operating Agreement***

2.3.1 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 has been amended from time to time to reflect the changes in the parties' interests, and was most recently amended and restated on 31 December 2019. Unless otherwise terminated in accordance with its terms, 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).

2.3.2 The terms of the Uquo JOA provide that, save for certain joint operations retained by the parties (mentioned below), with effect from 31 August 2018 (the "**Economic Effective Date**") Frontier and SUGL have separated the operations at the Uquo Field such that:

(a) SUGL has 100 per cent. of the economic benefit of, shall retain all gas produced and gross proceeds from (including associated natural gas produced from the Oil Project), shall pay for all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the Gas Project (being the exploration, appraisal, development and production of gas reservoirs at the Uquo Field);

(b) Frontier has 100 per cent. of the economic benefit of, shall retain all crude oil produced and gross proceeds from, shall pay for all costs, taxes and royalties, and take all risks, obligations and liabilities with respect to the Oil Project (being the exploration, appraisal, development and production of oil reservoirs and drilling and completion of the water-reinjection well at the Uquo Field); and

(c) Frontier and SUGL have maintained certain joint operations (detailed below), from which Frontier and SUGL shall own, take in kind and separately dispose of all hydrocarbons produced from the same *pro rata* to their participating interest share.

2.3.3 Frontier is the operator of the Uquo Field and responsible for undertaking all oil and gas operations on behalf of the parties (save with respect to the drilling and completion of new gas wells, which Frontier delegates responsibility for undertaking to SUGL until completion). The operations are conducted by a Field Operations Team, led by an operations director (appointed by Frontier). The Field Operations Team is comprised of: (i) a Gas Team (headed by the Head of Gas Operations), composed of SUGL secondees, which is responsible for managing and operating the Gas Project; and (ii) an Oil Team (headed by the Head of Oil Operations), composed of Frontier secondees, which is responsible for managing and operating the Oil Project.

2.3.4 Decisions in respect of the Uquo Field's 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 operations at the Uquo Field. The joint operating committee is made up of four members, two of whom are appointed by Frontier ("**Frontier Representatives**") and two of whom are appointed by SUGL ("**SUGL Representatives**"). All decisions of the joint operating committee require the unanimous vote of Frontier and SUGL. Save with respect to matters where a representative has a *bona fide* belief that it will result in a breach of compliance policies, applicable law or may lead to an operations conflict between the Oil Project and Gas Project, with respect to matters relating to:

(a) the Gas Project, the Frontier representatives must vote in accordance with the SUGL Representatives;

(b) the Oil Project, the SUGL representatives must vote in accordance with the Frontier Representatives;

(c) the joint operations and other matters which are non-specific to the Oil Project and Gas Project, the Frontier and SUGL Representatives may freely exercise their votes.

2.3.5 With respect to the Oil Project and Gas Project operations, the Uquo JOA provides for certain circumstances where a party can elect to have a well from the other party's project transferred to its own project.

2.3.6 In addition, if a party obtains all necessary approvals to drill for hydrocarbons deeper than the Uquo Field farm-out area (i.e. below 10,350 feet TVDSS) (a "**Deep Well**"), the other party shall, subject to certain conditions, have the right to elect to participate in the proposed Deep Well as a joint operation. If a Deep Well is conducted as a joint operation in accordance with the terms of the Uquo JOA, each party shall: (i) bear their participating interest share of costs and liabilities of conducting such exploration; and (ii) shall own, take in kind and separately dispose of all hydrocarbons produced from the same *pro rata* to their participating interest share.

2.3.7 Other joint operations include shared services, as agreed between the parties (including maintenance of joint property, asset protection and logistics), carried out by Frontier (as operator) on behalf of the parties. Until 31 December 2020, SUGL shall carry Frontier's share of shared services costs and expenses. From 31 December 2020, Frontier shall bear SUGL's shared services costs and expenses until it has paid an amount on SUGL's behalf equal to the carried amount paid by SUGL. The basis on which the allocation of the costs and expenses of the shared services shall be borne between the parties shall be agreed every two years between the parties.

2.3.8 The Uquo JOA includes a number of events of default, including where: (i) a party fails to pay certain payments to the other party relating to Deep Wells and the transfer of wells between parties; (ii) a party fails to perform its indemnity obligations under the Uquo FOA or Uquo JOA; (iii) an order is made by a court or an effective resolution is passed for the dissolution, liquidation or winding up of a party, or a party dissolves, liquidates or is wound up, or a receiver is appointed for a substantial portion of the party's assets; (limbs (i) to (iii) being "**Financial Defaults**"); and (iv) a party is responsible for an act or omission, contrary to the standard of a reasonable and prudent operator, which if not cured could be expected to result in a material risk to the non-defaulting party's title to its participating interest (a "**Title Risk Default**").

2.3.9 During any such event of default, subject to certain notice and cure periods, the defaulting party shall be restricted from taking certain actions and exercising certain of its rights under the Uquo JOA, including no rights to: (i) vote on joint operating committee decisions relating to joint operations; (ii) consent to or reject to another party's transfer of participating interest or take assignment of any portion of another party's participating interest; (iii) receive any entitlement for joint operations; and (iv) submit a proposal to drill a Deep Well to the joint operating committee. If a Financial Default is not remedied by the 180th day following the default, or, subject to certain exceptions, a Title Risk Default by the 30th day following notice of the default, the non-defaulting party may require the defaulting party to withdraw from the Uquo JOA.

2.3.10 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.

2.4 ***Uquo Upstream GSA***

2.4.1 On 6 November 2019, SUGL and Accugas entered into a natural gas sales agreement relating to the sale of unprocessed gas produced by SUGL to Accugas Limited ("**Uquo GSA**") for onward supply by Accugas Limited to its downstream customers under the Calabar PRG GSA, the Ibom Power GSA and the Unicem GSA. The Uquo GSA became effective on 14 November 2019. The previous gas sales arrangements between Accugas, SUGL and Frontier have been terminated.

2.4.2 The term of the initial period of the Uquo GSA is until 31 December 2028, thereafter the Uquo GSA shall continue until the expiry of 12 months' written notice from SUGL that it is no longer technically possible to produce commercial quantities of gas from the Uquo Field.

2.4.3 The Uquo GSA is on a pay when paid basis. Accugas Limited is obliged to pay SUGL for the quantities of gas supplied within five business days following the date on which Accugas Limited receives payment from the relevant downstream customer with respect to such quantities of gas (the "**Due Date**").

2.4.4 The source of the gas to be sold and delivered under the Uquo GSA shall be sourced at SUGL's discretion. Until 31 December 2028, the daily contract quantity shall be 195 MMscfpd. Thereafter, SUGL and Accugas Limited shall agree the daily contract quantity. The annual contract quantity shall be the daily contract quantity multiplied by number of days in a contract year. Subject to the terms of the Uquo GSA, SUGL shall have the right to temporarily and/or permanently reduce the daily contract quantity by a rateable amount in the event Accugas Limited fails to pay for gas delivered within certain time periods irrespective of whether Accugas Limited has received payment from the existing downstream gas sales customers for such quantities of gas. SUGL also has the right to suspend deliveries of gas on ten days' notice in the event Accugas Limited does not pay SUGL for such gas on the Due Date.

2.4.5 Accugas Limited has committed, subject to certain deductions, to a take or pay quantity per month equal to eighty per cent. of 1/12th of the annual contract quantity. Each quarter Accugas Limited shall be obliged to pay (at the applicable contract price) for the aggregate amount of gas it failed to take under the take or pay quantity. Subject to certain conditions, 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.

2.4.6 The contract price is a set base price ((unindexed) in $/Mscf) for the relevant contract year multiplied by a weighted average adjustment to reflect the inflation provisions Accugas Limited receives under the existing downstream gas sales agreements. The base price for each contract year is set out in a schedule to the Uquo GSA, and increases on the later of: (i) the date of the monthly invoice under which SUGL has delivered an aggregate of 110 Bscf of gas under the Uquo GSA; and (ii) 14 November 2021. 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.

2.4.7 Subject to the satisfaction of the certain conditions precedent, Accugas Limited is obliged to pre-pay for natural gas for a value of up to US$40 million, such pre-payment to be applied:

(a) up to US$8.4m to the holder of the SUGL 10.50 per cent. senior secure notes due 2026 with an aggregate principal amount of US$105 million;

(b) up to US$22.5 million (or US$18 million if SUGL is required to make a 20 per cent. payment contribution) towards drilling the next well at the Uquo Field;

(c) up to US$3.1 million towards SUGL's working capital requirements in line with an agreed working capital budget; and

(d) up to US$6 million towards funding SUGL's cost of repairing the Uquo-7 well.

2.4.8 After 1 July 2020, repayment of the expended prepayment amount by SUGL shall commence through applying a discount to the price of gas delivered to Accugas Limited until repaid. The applicable discount to be applied per contract year is set out in a schedule to the Uquo GSA.

2.4.9 SUGL may terminate the Uquo GSA:

(a) on 180 days' notice if: (i) Accugas Limited abandons its operations at the CPF; (ii) Accugas Limited breaches certain of the covenants it gives under the Uquo GSA and such breach is not remedied within 90 days; (iii) due to reasons of force majeure, Accugas Limited has not taken delivery of a quantity of gas equal to at least 75 per cent. of the annual contract quantity for a continuous period of 24 months; (iv) Accugas Limited fails to take delivery of at least 50 per cent. of the aggregate of the properly nominated quantities in any contract year and any take or pay payments remain outstanding on the last day of such contract year (regardless of whether the payment date for such take or pay payments have arisen under the terms of the Uquo GSA); and (v) for reasons other than force majeure, Accugas nominates zero quantities of gas for 45 day continuously, or for 90 days in aggregate, during any contract year.

(b) on 30 days' notice if Accugas Limited does not pay certain prepayment amounts to SUGL when due.

(c) with immediate effect if: (i) SUGL's right to suspend deliveries of natural gas to Accugas Limited has arisen and not ceased within 60 days; (ii) in accordance with the terms of the Uquo GSA, SUGL issues a notice to permanently reduce the daily contract quantity resulting in a reduced DCQ of zero; (iii) Accugas Limited diverts gas to customers other than the existing downstream customers without SUGL's written consent and does not within 30 days: (a) pay for the quantity of gas diverted; and (b) provide evidence that it is under no further obligation to supply such gas; (iv) an act of insolvency in relation to Accugas Limited occurs and continues for ten business days; (v) Accugas Limited fails to give notice of the occurrence of an acceleration event under certain Accugas Limited third party financing arrangements within five business days of such event; (vi) Accugas Limited does not provide to SUGL, after an acceleration event under certain Accugas Limited third party financing arrangements, with specific information relating to payments made by downstream customers within five business days from the due date of the same; (vii) after an acceleration event under certain Accugas Limited third party financing arrangements, Accugas Limited does not pay any amount to SUGL under a monthly invoice when due and payable; (viii) all of the existing downstream gas sales agreement terminate or expire; (ix) Accugas Limited does not pay certain prepayment amounts within ten business days; and (x) Accugas Limited breaches certain covenants and does not remedy the same within ten business days.

2.4.10 Accugas may terminate the Uquo GSA:

(a) on 180 days' notice if: (i) SUGL abandons its operations at the Uquo Field; (ii) SUGL breaches certain of the covenants it gives under the Uquo GSA and such breach is not remedied within 90 days; (iii) for reasons of force majeure, SUGL has been unable to make available for delivery a quantity of gas equal to at least 75 per cent. of the annual contract quantity for a continuous period of 24 months, provided that during each contract year of such 24 month period the quantities of gas properly nominated by Accugas Limited exceed 75 per cent. of the ACQ; and (iv) SUGL fails to make available in any contract year at least: (a) 50 per cent. of the annual contract quantity, provided Accugas Limited properly nominates quantities of gas which exceed 50 per cent. of the annual contract quantity during such time: or (b) 50 per cent. of the aggregate properly nominated quantities in such time

(b) with immediate effect if: (i) all of the existing downstream gas sales agreement terminate or expire; or (ii) an act of insolvency effects SUGL.

(c) Force majeure under the Uquo GSA includes force majeure which primarily affects a third party where that force majeure prevents, impedes or delays SUGL or Accugas Limited's performance under the agreement.

2.4.11 Except in relation to permitted assignments to affiliates, the parties shall not assign all or any part of their rights and obligations under the Uquo GSA without the prior written consent of the other parties. The parties may assign their rights by way of security for the purpose of or in connection with financing or re-financing their respective operations. SUGL is required to assign pro-rata its rights and obligations to any purchaser of SUGL's interests in the Uquo Field. To the extent of any partial assignment, SUGL and the purchaser shall be jointly and severally liable.

2.4.12 Accugas Limited is required to pay to SUGL an annual fixed administration fee and management fees. Each fee is paid in two equal instalments per contract year.

2.5 ***SUGL Services Agreement***

2.5.1 On 14 November 2019, the Company and SUGL entered into the SUGL Services Agreement which sets out the terms on which each entity can provide from time to time certain services to the other. The Company can also request that SUGL provides services to one of the SAVE Group Companies (consisting of affiliates of the Company other than Seven Energy (BVI) Limited, Seven Petroleum (Uquo) Limited, Accugas Holdings UK plc, Accugas UK Limited, Exoro Holding BV and Accugas Limited). The Company may perform any requested services itself, or procure that one of the SAVE Group Companies performs such service. The services are to be performed to the highest level of care, skill and diligence in accordance with best practice in the service provider's industry, profession or trade.

2.5.2 Subject to certain exclusions, the services provided are charged on a pass through basis in accordance with an accounting procedure scheduled thereto, save that the Company may charge an indirect charge for the cost of indirect services and related office costs of the Company and the SAVE Group Companies not otherwise set out in the accounting procedure. This indirect charge is based on a sliding scale of five per cent. to one per cent. of total expenditure depending on the amount of total expenditure per annum (the higher the total expenditure, the lower the percentage of indirect charge), with a minimum charge of US$200,000 per calendar year. If the estimated cost of a major project is estimated to be more than US$10 million, the Company can charge a separate indirect charge for such project if approved by the parties at the time of approval of the project.

2.5.3 The services to be provided under the agreement include: (i) sub-surface activities; (ii) upstream asset management; (iii) executive management functions: (iv) QHSE; (v) HR; (vi) security and transport; (vii) finance; (viii) legal; (ix) administrative; (x) IT; and (xi) such other services as may be agreed between the parties. Any services provided to SUGL will only be those necessary for the running of its business in a manner consistent with its business plan and budget from time to time.

2.5.4 The party requesting the services may immediately terminate the SUGL Services Agreement if the services provider commits a material breach which cannot be cured, or if it can be cured, has not been cured within seven days of being notified. Either party may immediately terminate if the other party takes any step or action in connection with entering bankruptcy, administration, provisional liquidation or any composition or arrangement with creditors (other than a solvent restructuring), being wound up, having a receiver appointed to any of its assets or ceasing to carry on its business.

2.6 ***Transportation Services Agreement***

2.6.1 On 30 September 2019, SUGL and Frontier entered into the Transportation Services Agreement (the "**Uquo TSA**") which sets out the terms on which Frontier shall transport SUGL's quantities of crude oil (if any) and condensate through a system of pipelines from the CPF to

QIT for onward sale to ExxonMobil under the terms of the ExxonMobil COSA. The Uquo TSA became effective on 31 December 2019.

2.6.2 The Uquo TSA provides that it shall remain in full force and effect until the earlier of: (i) the date SUGL permanently stops producing hydrocarbons at the Uquo Field; (ii) the date that Frontier stops transporting crude oil and condensate through the relevant pipeline system; (iii) on 180 days' written notice by SUGL that it intends to stop delivering crude oil and condensate under the Uquo TSA; and (iv) 29 November 2022, save that if the ExxonMobil COSA and the CHA are extended beyond this date, or replaced with new contracts, the Uquo TSA shall be effective until such new termination date.

2.6.3 Subject to certain conditions, Frontier is obliged to accept quantities of SUGL's crude and condensate, meeting the delivery specifications, not exceeding 1,000 bopd. All crude oil delivered under the Uquo TSA shall originate from the Uquo Field, unless such crude would not cause Frontier to be in breach of its obligations under the ExxonMobil COSA and/or CHA. Frontier shall sell the quantities of SUGL's crude oil and condensate delivered by SUGL pursuant to the terms of the ExxonMobil COSA. The quantities sold are calculated under the ExxonMobil COSA taking account of pipeline losses, shrinkage and all other physical losses.

2.6.4 The Uquo TSA provides that Frontier shall pay to SUGL any payment made by ExxonMobil to Frontier with respect to SUGL's crude oil and condensate (less certain costs incurred by Frontier under the CHA). Frontier is not required to pay any such amounts to SUGL unless and until Frontier receives valid payment from ExxonMobil. For the transportation services, SUGL is required to pay Frontier, on a monthly basis, a certain share of the following costs incurred by Frontier on a pass through basis: (i) operating expenditures relating to the FUN Manifold and Pipeline; (ii) the costs of maintaining the right of way associated with the FUN Manifold and Pipeline; (iii) remedial capital expenditures (not including any expansion capital expenditures) relating to the FUN Manifold and Pipeline and QIT Pipeline; (iv) operating expenditures of the FUN Manifold and Pipeline and QIT Pipeline; and (iv) costs incurred by Frontier under the CHA.

2.6.5 Frontier has the right to suspend and/or reduce the quantity of SUGL's crude oil and condensate accepted for delivery and suspend the transportation services in certain circumstances, including: (i) subject to Frontier's obligation to use reasonable endeavours to accept such crude oil and condensate, where SUGL's crude oil and condensate does not meet delivery specifications; (ii) there is a scheduled outage; (iii) Frontier receives an instruction under the CHA requiring the suspension or reduction of deliveries at QIT; (iv) SUGL fails to meet its metering obligations under the Uquo TSA such that it prevents the performance of transportation service by Frontier; (v) any payment due by SUGL under the Uquo TSA has not been made within 60 days of its due date; and (vi) a force majeure event. Frontier is obliged to use it reasonable endeavours to restore the transportation services as soon as reasonably practicable.

2.6.6 The Uquo TSA provides that either party may terminate by written notice: (i) after failing to remedy/provide a proposal for remedying (reasonably satisfactory to the non-defaulting party) such breach within 45 days from the non-defaulting party delivering a notice of the breach, upon giving 60 days' written notice in the event the defaulting party materially fails to perform or comply with any of its material obligations; (ii) upon 60 days' notice for failure to pay any amounts due under the Uquo TSA; (iii) if an order is made or resolution passed for the winding up of the other party; (iv) if a receiver, administrator or administrative receiver is appointed over the whole or any material part of the assets of the other party, or the other party ceases to carry on the whole or a substantial part of its business; (v) breach of any anti-bribery and corruption warranties set out in the Uquo TSA; and (vi) upon 30 days' notice if the other party is excused from the performance of any material obligation under the Uquo TSA for a continuous period of 18 months due to a force majeure event.

2.6.7 Pursuant to the Uquo TSA, a party shall be excused from the performance of any obligation under the Uquo TSA if such failure is attributable to an event of force majeure and obligations are notified to the other party as soon as reasonably practicable of the circumstances constituting the force majeure. The affected party is required to do all such things a reasonable and prudent operation would do to continue to perform its obligations under the Uquo TSA and to minimise the effect of the force majeure event.

3. MATERIAL CONTRACTS RELATING TO THE MIDSTREAM ASSETS

3.1 *Accugas SHA*

3.1.1 On 14 November 2019, African Midstream Holdings Mauritius ("**AIIM Accugas**"), Savannah Petroleum Nigeria Midstream Limited ("**Accugas TopCo**") and Accugas Holdings UK plc ("**Accugas HoldCo**") entered into a shareholders' agreement relating to Accugas HoldCo (the "**Accugas SHA**").

3.1.2 There shall be no more than five directors on the board of Accugas Holdco. The Accugas TopCo shall have the right to appoint three directors and AIIM Accugas shall have the right to appoint two directors.

3.1.3 There shall be no more than five directors on the board of Accugas Limited. Accugas TopCo shall have the right to appoint three directors of Accugas Limited and AIIM Accugas shall have the right to appoint two directors of Accugas Limited. The CEO shall be a director of Accugas Limited (as an Accugas TopCo nominated director). Accugas Topco shall propose candidates for the role of chief executive officer of Accugas Limited for approval by AIIM Accugas (acting reasonably). Accugas TopCo and AIIM Uquo shall give joint written notice to the board of Accugas Limited to appoint the CEO.

3.1.4 The initial rolling five year business plan and rolling annual budget has been approved by Accugas TopCo and AIIM Accugas. Each subsequent business plan and budget shall be prepared by the CEO and senior management of Accugas Limited and submitted annually to the board of Accugas Holdco for approval. The board of Accugas HoldCo shall consult with, and reasonably consider the comments of, the shareholders.

3.1.5 Shareholders are not obliged to provide any capital to Accugas HoldCo by way of subscription for further shares or by way of a loan. Subject to the approval of the board of Accugas HoldCo and the terms of any third party financing agreements, Accugas HoldCo may request further funding from the shareholders. Each shareholder may provide to Accugas HoldCo its proportion of any additional funding in cash by way of a shareholder loan on certain agreed commercial terms (an "**Accugas Additional Shareholder Loan**"). If a shareholder elects not to provide an Accugas Additional Shareholder Loan, the other shareholders can may elect to provide all or part of the funding shortfall by providing an additional shareholder loan on certain agreed commercial terms (an "**Accugas Additional Shortfall Loan**"). If any employees join any employee share scheme of the Company or its affiliates, the corresponding amount of such employee share scheme shall be deemed an interest free shareholder loan between Accugas HoldCo and Accugas TopCo (an "**Accugas Employee Share Scheme Loan**").

3.1.6 Subject to: (i) the terms of any third party financing agreements; (ii) applicable law and insolvency legislation; (iii) maintaining a minimum US$10 million cash reserve; and (iv) making appropriate provision for working capital and liabilities of the group as the board of Accugas HoldCo deems appropriate; the board of Accugas HoldCo shall resolve (and procure that the group companies resolve) to distribute all distributable cash to the shareholders on a quarterly basis or as soon as possible after a capital event. As soon as possible after an cash is resolved to be distributable, such cash shall be allocated and distributed in the following priority: (i) repayment of interest and principal amounts outstanding under all Accugas Additional Shortfall Loans; (ii) repayment of interest and principal amounts outstanding under all Accugas Additional Shortfall Loans; (iii) repayment to Accugas TopCo of the amounts outstanding under all Accugas Employee Share Scheme Loans; and (iv) the remainder to the shareholders as a dividend *pro rata* to the number of shares in Accugas HoldCo held at the time.

3.1.7 The following reserved matters (applicable to Accugas HoldCo, Accugas MidCo, Exoro and Accugas Limited) shall require an 85 per cent. majority vote of the shareholders:

(a) any change to the articles of Accugas Holdco, the business, the auditors, the distribution policy, the share capital or share rights;

(b) the execution of any new agreement or contract relating to any downstream contracts under which gas is supplied by a group company to a downstream customer; and any material amendment, consent or waiver of a material term of any new or existing downstream contract;

(c) 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;

(d) 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 business;

(e) change to the business plan and budget (other than due to inflation or the undertaking of a new revenue generating activity) that may result in an increase of the aggregate of total operating and administrative costs in a financial year by more than fifty per cent. when compared against the amount budgeted for that financial year;

(f) approval of any New Project (details below)

(g) settlement of disputes with a value of over US$5 million or relating to the material assets;

(h) winding up, proposing any arrangement or composition with creditors of Accugas HoldCo, applying for an administration order or appointing a receiver or administrator in respect of Accugas HoldCo;

(i) any material transaction with a shareholder or any of its affiliates, or any guarantee or indemnity not in the ordinary course of business and on arm's length terms;

(j) any material amendment to the Accugas Services Agreement;

(k) mergers and acquisitions, or the entry into of any partnership, joint venture or consortium agreement not included in the business plan and budget;

(l) acquiring or disposing of any material undertaking of the company or closing down any material business operation;

(m) any issue of share capital other than to a group company which is wholly owned by Accugas HoldCo; and

(n) sale of shares in Accugas MidCo, Exoro or Accugas Limited.

3.1.8 Save for a permitted transfer, shareholder consent is required for a shareholder to transfer any shares. Permitted transfers are:

(a) Where Accugas TopCo wishes to transfer all or part of its shares in Accugas HoldCo to a third party purchaser on arm's length terms, Accugas TopCo must procure that the third party purchaser, subject to certain conditions, makes a written offer to AIIM Accugas to purchase a *pro rata* amount of its shares in Accugas HoldCo.

(b) Where Acccugas TopCo wishes to transfer all (but no part only) of its shares in Accugas HoldCo to a *bona fide* third party purchaser on arm's length terms, subject to certain conditions, Accugas TopCo shall have the option to require the other shareholders to sell their shares to the third party purchaser. If the proposed purchase price of the shares held by AIIM Accugas is less than the higher of: (i) 20 per cent. IRR on AIIM Accugas' total investment expenditure in Accugas HoldCo at such date; or (ii) 2.5 times AIIM Accugas' total investment expenditure in Accugas HoldCo at such date, AIIM Accugas has the right to decline to sell its shares in Accugas HoldCo. If AIIM Accugas declines the third party purchaser's offer, it shall no longer have the right to exercise the Accugas Exit Option (details below).

(c) Save if the transferee is a restricted person, where a shareholder wishes to transfer to an affiliate.

(d) Where a shareholder wishes to sell all or part of its shareholding (the "**Accugas Sale Shares**") in Accugas Holdco the selling shareholder shall notify the other shareholders in writing of its intention to sell the Accugas Sale Shares, and each remaining shareholder may notify the selling shareholder in writing of the cash price (the "**Accugas Offer Price**") at which it would be willing to purchase the Accugas Sale Shares and the key terms of such purchase (the "**Accugas Offer Terms**"). If the selling shareholder does not accept any Accugas Offer Terms or Accugas 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 Accugas Offer Price and on materially the same terms as the Accugas Offer Terms. Where the proposed purchaser is an Accugas 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 Accugas TopCo considers, acting reasonably, would restrict or prevent Accugas TopCo or Accugas Limited 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 Accugas Sale Shares for the same price and on the same terms as offered by such Accugas Matching-Right Transferee.

3.1.9 Under the Accugas SHA, AIIM Accugas has a non-transferrable option to require Accugas TopCo to purchase all of AIIM Accugas' shares in Accugas HoldCo on any date falling within 30 calendar days of 14 November 2023 ("**Accugas Exit Option**"). The consideration for such shares (the "**Accugas Exit Consideration**") is to be calculated in accordance with an agreed Accugas Exit Consideration formulae at the date AIIM Accugas serves notice on Accugas TopCo to exercise its option. If prior to the date the Accugas Exit Option arises the Company is taken over by a third party, the Accugas Exit Consideration shall be calculated in accordance with the Accugas Exit Consideration formulae and capped at an amount equal to 18 per cent. IRR on AIIM Accugas' total investment expenditure at such date in Accugas HoldCo.

3.1.10 Any shareholder or any of its directors on the board of Accugas Limited may propose that a group company undertakes a new project to build, own or operate infrastructure for the purpose of processing and/or transporting gas in an area within a radius of 30 km from the CPF ("**New Project**"). A decision to pursue a New Project is a shareholder reserved matter. If the shareholders elect not to approve the New Project, the proposing shareholder or its affiliates shall have the right to pursue the unapproved New Project outside the group companies. With respect to an unapproved New Project, Accugas HoldCo and Accugas Limited shall provide reasonable assistance on reasonable commercial terms to the proposing shareholder to implement such unapproved New Project by: (i) providing reasonable access to Accugas Limited's infrastructure (subject to Accugas Limited determining such access is technically feasible, and acting reasonably and in good faith in agreeing reasonable commercial terms for the assistance, and provided that such assistance does not unduly interfere with Accugas Limited's business operations); (ii) allowing facilities relating to the unapproved New Project to be constructed on land owned, leased or licenced by Accugas Limited (provided always that doing so does not constitute a breach by Accugas Limited of any lease, sub-lease or certificate of occupancy to which it is a party); and (ii) charging an access tariff to use any Accugas Limited pipelines to be agreed between the proposing shareholder and Accugas Limited acting reasonably and in good faith.

3.1.11 The Accugas SHA provides that if the joint venture parties to Stubb Creek Field make a final investment decision to develop the Stubb Creek gas field and the joint venture parties give notice that they wish to supply gas to the Accugas facilities, the shareholders are obliged to procure that Accugas Limited enters promptly into a gas sales agreement in relation to the 2C resources included in the CPR for the Stubb Creek Field at the date of the Accugas SHA (the "**Stubb Creek GSA**").

3.1.12 The terms of the Stubb Creek GSA and any new gas sales agreement between Accugas Limited and the Company and its affiliates shall be on substantially similar terms as the Upstream GSA save that the contract price per Mscf pursuant to such new GSA shall be equal to the sum of:

(a) US$1.70; and

(b) the weighted average percentage increase in achieved price pursuant to Accugas Limited's downstream contracts (where weighting shall be allocated proportionally on the daily contract quantity of the relevant downstream contracts out of the aggregate daily contract quantity under all downstream contracts) since 14 November 2019; plus

(c) 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 US$3.40 per Mscf.

3.1.13 Pursuant to the terms of the Accugas SHA, in the event there is insufficient capacity in the Accugas facilities to accept all contracted gas, Accugas Limited shall allocate available capacity in the following priority: (i) gas supplied under the Upstream GSA and Stubb Creek GSA; (ii) other gas supplied from the Uquo Field or Stubb Creek Field and gas from any other field in which SUGL, UERL or any affiliates hold an interest; and (ii) any other source. Any gas sales, transportation and processing or other agreement at the Accugas facilities entered into by Accugas Limited in relation to any other source of gas shall be on an interruptible basis in order to make capacity available in such priority. This order of priority and contracting basis shall also apply to any other processing facilities owned by Accugas Limited or its affiliates, provided that the price paid by Accugas Limited for gas under the SUGL GSA and Stubb Creek GSA is not higher than the price payable in respect of any other source.

3.2 *Accugas Services Agreement*

3.2.1 On 14 November 2019, the Company and Accugas entered into the Accugas Services Agreement which sets out the terms on which each entity can provide from time to time certain services to the other, the Company can also request that Accugas provides services to the one of the SAVE Group Companies (consisting of affiliates of the Company other than Seven Energy (BVI) Limited, Seven Petroleum (Uquo) Limited, Accugas Holdings UK plc, Accugas UK Limited, Exoro Holding BV and Accugas). The Company may perform any requested services itself, or procure that one of the SAVE Group Companies performs such service. The services are to be performed to the highest level of care, skill and diligence in accordance with best practice in the service provider's industry, profession or trade.

3.2.2 Subject to certain exclusions, the services provided are charged on a pass through basis in accordance with an accounting procedure scheduled thereto, save that the Company may charge an indirect charge for the cost of indirect services and related office costs of the Company and the SAVE Group Companies not otherwise set out in the accounting procedure. This indirect charge is based on a sliding scale of five per cent. to one per cent. of total expenditure depending on the amount of total expenditure per annum (the higher the total expenditure, the lower the percentage of indirect charge), with a minimum charge of US$200,000 per calendar year. If the estimated cost of a major project is estimated to be more than US$10 million, the Company can charge a separate indirect charge for such project if approved by the parties at the time of approval of the project.

3.2.3 The services to be provided under the agreement include: (i) executive management functions: (ii) QHS; (iii) HR; (iv) security and transport; (v) Lagos finance; (vi) legal; (vii) administrative; (viii) IT; and (ix) such other services as may be agreed between the parties. Any services provided to Accugas will only be those necessary for the running of its business in a manner consistent with its business plan and budget from time to time.

3.2.4 The party requesting the services may immediately terminate the Accugas Services Agreement if the services provider commits a material breach which cannot be cured, or if it can be cured, has not been cured within seven days of being notified. Either party may immediately terminate if the other party takes any step or action in connection with entering bankruptcy, administration, provisional liquidation or any composition or arrangement with creditors (other than a solvent restructuring), being wound up, having a receiver appointed to any of its assets or ceasing to carry on its business.

4. GAS SALE AND PURCHASE AGREEMENTS

4.1 *Calabar PRG GSA*

4.1.1 On 8 December 2011, Accugas Limited entered into a 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.

4.1.2 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 required to supply gas to CGCL under the Calabar PRG GSA 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.

4.1.3 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 five business days later, being 22 September 2017. First deliveries under the Calabar PRG GSA occurred on 22 September 2017.

4.1.4 Under the Calabar PRG GSA, the daily contract quantity is 131 MMscfpd and the annual contract quantity is 131 MMscfpd 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 150 MMscfpd, capped at a maximum of 150 MMscfpd 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 to be 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.

4.1.5 The contract price is US$3.16 per MMBtu for the first year, to be increased progressively over the first seven years of the contract to US$4.74 per MMBtu (indexed annually by reference to US 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.

4.1.6 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$.

4.1.7 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 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.

4.1.8 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 days 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.

4.1.9 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.

4.1.10 Where CGCL fails to pay amounts due pursuant to the agreement, interest at five 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 ten 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.

4.1.11 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 assign 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).

4.1.12 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).

4.1.13 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).

4.1.14 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). The agreement can be terminated by Accugas Limited in the event of a change of control of CGCL in breach of the terms of the agreement.

4.1.15 The Calabar PRG GSA is governed by the laws of the Federal Republic of Nigeria.

4.2 *PRG Agreements*

4.2.1 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.

4.2.2 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 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 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 for: (i) Accugas assigning its rights under the Support Agreement by way of security which does not require consent of the other parties; and (ii) concurrently with the assignment of the Calabar PRG GSA and subject to the written consent of the other parties and the International Development Association.

4.2.3 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.

4.2.4 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.

4.2.5 Accugas Limited also makes the following covenants to the International Development Association:

(a) 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;

(b) not to bring claims during a moratorium period;

(c) deliver a notice of Credit Support;

(d) co-operate in good faith with the International Development Association in relation to any breaches notified by the International Development Association;

(e) 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;

(f) 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;

(g) 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;

(h) to implement and maintain policies and procedures to monitor compliance with environmental and social laws, a resettlement action plan and environmental impact assessments;

(i) keep the International Development Association informed of payment and default notices or demands pursuant to the Calabar PRG GSA and Support Agreement;

(j) 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);

(k) 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

(l) 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.

4.2.6 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.

4.2.7 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.

4.2.8 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.

4.2.9 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.

4.2.10 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.

4.2.11 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.

4.2.12 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.

4.3 ***Ibom Power GSA***

4.3.1 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.

4.3.2 Delivery was initially on a take or pay basis for 100 per cent. of the ACQ being 43,500 MMBtu 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 43,000 MMBtupd. 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 20,000 MMBtu and the Maximum Daily Quantity ("**MDQ**") became 27,000 MMBtu. 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

DCQ, 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 DCQ to 43,500 MMBtu ("**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 US$0.40 per MMBtu plus a subsidy of US$1.60 per MMBtu payable by the Akwa Ibom State Government to deliver to Accugas Limited a price of US$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 movement in US CPI for the preceding 12 months. By an addendum dated 1 August 2016, the parties agreed a new price of US$3.30 per MMBtu, 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.

4.3.3 The Ibom Power GSA provides that Ibom Power pay an advance of US$63.5 million for future gas deliveries. The Ibom Settlement Agreement as summarised in section 4.3.4 of this Part 11 provides for the payment of outstanding amounts in accordance with a payment plan.

4.3.4 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 US$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.

4.3.5 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 provided an executed guarantee from the Akwa Ibom State Government dated 24 June 2010 (the "**Akwa Guarantee**"), for the Naira equivalent of US$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 had recourse to the Akwa Guarantee and was 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. Accugas Limited has confirmed that the Akwa Guarantee is not currently accessible due to an injunction which has effectively prevented Accugas Limited from drawing funds from the Akwa Ibom State government account in the last four years.

4.3.6 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.

4.3.7 The Ibom Power GSA is governed by the laws of the Federal Republic of Nigeria.

4.4 ***Unicem GSA***

4.4.1 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 to 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.

4.4.2 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 230,000,000 scm of gas (and the daily contract quantity was plus or minus ten per cent. of 710,000 scm per day) until 1 July 2016 and thereafter, the annual contract quantity became 400,000,000 scm (and the daily contract quantity, plus or minus ten per cent. of 1,420,000 scm per day). 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 US$6.63 per Mscf and following the ramp-up period which ended in November 2016, for the remainder of the contract, US$5.00 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).

4.4.3 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.

4.4.4 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 US$200 million, which sum shall be reduced by US$10 million for each contract year which has elapsed since 2012 prior to such termination and US$27,397 for each day that has elapsed since the last day of the contract year immediately preceding the effective date of the termination.

4.4.5 Unicem's obligations under the Unicem GSA are guaranteed to a value of NGN 1.45 billion (approximately US$4 million) under a bank guarantee in favour of Accugas Limited executed by Standard Chartered Bank Nigeria Limited and dated 14 January 2020. 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 12 January 2021. The guarantee cannot be transferred or assigned.

4.4.6 The Unicem GSA is governed by the laws of the Federal Republic of Nigeria.

4.5 ***First GSA***

4.5.1 The agreement (the "**First GSA**") came into effect on 28 January 2020, with a contractual start date from the date that First Independent Power Company provides security to Accugas Limited in the form of a US$1.5 million letter of credit, representing 30 days' gas supply of 20 MMscfpd (which the Company has confirmed is not in place as at the date of this document). Unless extended in accordance with its terms, the agreement will terminate on the first anniversary of the contractual start date.

4.5.2 The First GSA provides that First Independent Power Limited may nominate an amount of gas up to a maximum of 35 MMscfpd for delivery on the following day, of which Accugas Limited may choose to accept, vary or reject. For accepted nominations, First Independent Power Limited will pay to Accugas Limited a gas sales price of US$2.50 per MMBtu and will pay an additional transportation tariff to transport the gas from the Uquo CPF to the Ikot Abasi Gas Receiving Facility at a rate specified in the gas transportation agreement which is yet to be agreed.

4.5.3 If First Independent Power Limited takes either (i) less than 80 per cent., or (ii) more than 120 per cent. of the daily nominated quantity, First Independent Power Limited will pay a ten per cent. premium on the price for amounts of gas falling below or above such thresholds. If Accugas Limited delivers less than 80 per cent. of the daily nominated quantity, First Independent Power Limited will be entitled to a ten per cent. discount on any amount under the 80 per cent. threshold.

4.5.4 The First GSA can be terminated by Accugas Limited by giving ten days' notice to First Independent Power Limited for certain events of default as defined in the agreement. There is a reciprocal right for First Power Independent Limited to terminate by serving notice on Accugas Limited for Accugas Limited's insolvency or breach of their material obligations under the agreement.

4.5.5 The First GSA is governed by the laws of the Federal Republic of Nigeria.

5. MATERIAL CONTRACTS RELATING TO THE STUBB CREEK FIELD

5.1 *Stubb Creek Field Farm-out Agreement*

5.1.1 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.

5.1.2 A DPR letter dated 12 April 2016 to Universal approved the renewal of the Stubb Creek Field licence for a period of 10 years effective from 1 May 2016. This was confirmed in a letter of good standing from the DPR dated 18 February 2020.

5.1.3 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 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 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.

5.1.4 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.

5.1.5 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.

5.1.6 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.

5.1.7 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.

5.2 ***Stubb Creek Funding Agreement and Joint Operating Agreement***

5.2.1 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.

5.2.2 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.

5.2.3 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 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.

5.2.4 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.

5.2.5 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 to nil per cent. and if Universal fails to pay five consecutive cash calls, its profit oil allocation is decreased to 15 per cent.

5.2.6 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.

5.2.7 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.

5.2.8 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.

5.2.9 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.

5.3 ***Mobil Crude Handling Agreement***

5.3.1 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 Company Nigeria Limited (together, the "**FUN Group**") with respect to this paragraph 1.3) ("**CHA**"). The term of the CHA was for five years from the date of execution, expiring at the end of November 2017, however, the CHA was extended pursuant to an amendment agreement dated January 2018 extending the term to 29 November 2022.

5.3.2 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.

5.3.3 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.

5.3.4 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.

5.3.5 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.

5.3.6 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.

5.3.7 By a separate and concurrent agreement described in paragraph 5.4 below, MPN's affiliate, ExxonMobil Sales and Supply LLC ("**ExxonMobil S&S**"), committed to purchase all volumes of Qua Iboe Crude stored and transferred by MPN.

5.4 ***Exxon Mobil Crude Oil Sales Agreement***

5.4.1 On 30 November 2012, ExxonMobil S&S and the FUN Group entered into an agreement pursuant to which the FUN Group have agreed to sell Qua Iboe Crude to ExxonMobil S&S (the "**ExxonMobil COSA**").

5.4.2 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 was extended to 29 November 2022 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&S's payment for the purchase of the remaining inventory of the FUN Group in the QIT.

5.4.3 The ExxonMobil COSA specifies 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.

5.4.4 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 S&S and title to and risk of loss passes from the FUN Group to ExxonMobil S&S as the cargo passes the permanent inlet flange of the vessel at the load port.

5.4.5 Pursuant to the ExxonMobil S&S 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 S&S 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.

5.5 ***FUN JOA***

5.5.1 On 28 August 2014, the FUN Group (as operators of the Uquo, Stubb Creek and Qua Iboe marginal fields) entered into a joint operating agreement with respect to certain facilities which connect to the QIT through which they export processed crude oil ("**FUN JOA**").

5.5.2 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.

5.5.3 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.

5.5.4 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.

5.5.5 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.

5.5.6 The FUN JOA was amended and restated on 24 February 2020, but no material changes were made.

5.6 ***Savannah Petroleum (Stubb Creek) Limited SHA***

5.6.1 On 23 January 2019, Savannah Petroleum Nigeria Limited ("**SPN**"), STC Joint Venture Limited ("**STC**") and Savannah Petroleum (Stubb Creek) Limited ("**SPSCL**") entered into a shareholders' agreement relating to SPSCL (the "**SPSCL SHA**").

5.6.2 SPSCL has one hundred shares in issue and the shares are divided into two classes (A shares and B shares). STC holds 75A Shares and SPN holds 25 B shares.

5.6.3 STC's A shares have no right to receive any dividends, interest, bonuses or distributions or other payments whereas SPN's B shares hold the right to all economic benefit.

5.6.4 SPSCL shall have a minimum of two directors on the board of which STC is entitled to appoint one director and SPN is entitled to appoint four directors. The chairperson shall be an SPN board member and will not have a casting vote. The quorum for any director meeting requires at least two SPN directors.

5.6.5 STC cannot transfer or dispose of its shares without the prior written consent of SPN.

5.6.6 The agreement will terminate when one party ceases to hold any shares in SPSCL.

5.6.7 The agreement is governed by the laws of England and Wales and any disputes will be resolved exclusively by the English courts.

6. MATERIAL CONTRACTS RELATING TO THE EAST HORIZON PIPELINE

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.

By court order dated 14 December 2016 the Federal High Court at Lagos 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.

6.1 *Pipeline MOU*

6.1.1 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**").

6.1.2 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 (and making EHGC the gas supplier) by deed of assignment dated 29 March 2007. The NGC GSA was ratified by a deed of ratification dated 16 December 2013 between NGC, Unicem and EHGC. The NGC GSA has subsequently been terminated.

6.1.3 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 hence the reason for the assignment of the NGC GSA from Unicem to EHGC and the entry into the Unicem GSA between EHGC and Unicem.

6.1.4 At the date of the Pipeline MOU, an amount of NGN 7,332,021,301.06 was agreed to be owed by EHGC to NGC in respect of the value of gas delivered by NGC to EHGC under the NGC GSA net of the amortised East Horizon Pipeline construction capex amount owed by NGC to EHGC (the "**Outstanding NGC Amount**").

6.1.5 Under the Pipeline MOU, the parties agreed that the transfer of a 15 per cent. interest in the East Horizon Pipeline from EHGC to NGC would discharge an amount of NGN 5,801,250,000.00 out of the Outstanding NGC Amount.

6.1.6 The parties agreed that a further amount of NGN 991,413,138 of the Outstanding NGC Amount would be paid to NGC by Oando and an amount of NGN 539,358,163 of the Outstanding NGC Amount would be paid to NGC by SEIL, in satisfaction of EHGC's payment obligations to NGC under the NGC GSA.

6.1.7 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 (except to the extent expressly settled in the Ownership Agreement) 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.

6.2 ***Ownership Agreement***

6.2.1 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.

6.2.2 The consideration for this transfer will be the release by NGC of its entitlement to recover NGN 5,801,250,000.00 of the NGC Outstanding Amount. 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 which relate to the ownership interest to be transferred. In addition EHGC is required to indemnify NGC for any actual loss suffered as a result of environmental liability arising under or in connection with such interest prior to completion (capped at US$18.75 million).

6.2.3 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**"), together with the consent of the Minster of Petroleum Resources; the Company has confirmed that negotiations between NGC and EHGC (now Accugas) with respect to the PMA remain ongoing and EHGC is working with NGC to seek satisfaction of the conditions precedent. The long stop date for the satisfaction of the Ownership Agreement conditions has expired, but the Directors believe that continued interaction between Accugas and NGC evidences NGC's intention to continue to work towards completion of the Ownership Agreement on its current terms (which remains the intention of Accugas).

6.2.4 In the period between signing the Ownership Agreement and completion, 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.

6.2.5 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 date on which the offer notice is sent 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.

Appendix A

OVERVIEW OF NIGERIA'S NATIONAL LEGISLATIVE FRAMEWORK

1. CONSTITUTION OF THE FEDERAL REPUBLIC OF NIGERIA 1999 (AS AMENDED) , 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 of Nigeria.

2 THE PETROLEUM ACT, 1969 (AS AMENDED) CAP P10, LFN 2004

2.1 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 of Petroleum Resources (the "**MPR**") the right to exercise general supervision over all operations carried on under licences and leases granted under the PA. The PA also gives the MPR the power to make regulations to cover a plethora of subjects relating to anything to be done in pursuance of the PA. In the light of this, Nigeria has several regulations which deal with specific matters in the oil and gas sector.

2.2 The primary regulator of the Nigerian oil and gas industry is the MPR and it performs its regulatory functions usually through the Department of Petroleum Resources (the "**DPR**") (which is a department of the Ministry of Petroleum Resources). 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.

3. THE PETROLEUM PROFIT TAX ACT 1959 (AS AMENDED) CAP LFN 2004 (the "PPTA")

3.1 The PPTA imposes tax upon the profit of companies engaged in petroleum operations, realised from the extraction of petroleum in Nigeria and also regulates the collection of imposed tax by the Federal Inland Revenue Services. This includes companies engaged in the operation and production (including sale thereof) of crude oil and liquefied and associated natural gas operation.

3.2 Recently, the Finance Bill was assented to by the President, which repealed the provision of section 60 of the PPTA that hitherto excluded income or dividends paid out of any profits which are taken into account under the PPTA from any other tax under any other statute. The Finance Act also increased value added tax payable to 7.5 per cent.

4. NIGERIAN NATIONAL PETROLEUM CORPORATION ACT 1977, CAP N123, LFN 2004

4.1 NNPC is the state oil corporation in Nigeria (established on 1 April 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 of State for Petroleum Resources 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.

4.2 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 for 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 Mallam Mele Kyari

5. PETROLEUM PRODUCTS PRICING REGULATORY AGENCY ACT (ESTABLISHMENT) CAP P43, LFN 2004

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.

6. NIGERIAN OIL AND GAS INDUSTRY CONTENT DEVELOPMENT ACT, 2010 (the "LOCAL CONTENT ACT")

The Local Content Act provides a framework for increasing Nigerian participation in all sectors of the Nigerian oil and gas industry. The Local Content 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 Local Content 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 to assess a 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.

7. OIL TERMINAL DUES ACT

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 (the "**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.

8. OIL IN NAVIGABLE WATERS ACT

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 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.

9. MERCHANT SHIPPING ACT

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.

10. COASTAL AND INLAND SHIPPING (CABOTAGE) ACT

10.1 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. To ensure compliance with Cabotage rules, all vessels intending to participate in local trade are required to register for the Cabotage trade.

10.2 The Minister of Transportation had in exercise of his powers under Section 46 of the Cabotage Act, issued the Guidelines for the Implementation of the Cabotage Act wherein the Drilling Rigs was included as vessels.

10.3 In 2019, the Federal High Court ("**FHC**") in the case of Seadrill Mobile Units Nigeria Ltd V, the Honourable Minister of Transportation & 2 Ors. held that Rigs fall within the scope of the definition of vessels under the Cabotage Act. A few days after the judgment was passed, the Court of Appeal in the case of Transocean Support Services Nigeria Limited & 3Ors V. NIMASA and Minister of Transport, overruled the decision of the FHC in the Seadrill case. The Court of Appeal stated inter alia that a Rig was not expressly listed as one of the vessels eligible for registration under the Cabotage Act, thus the attempt by the Minister of Transport to list Rigs in the Cabotage Guidelines is improper.

11. THE ENVIRONMENTAL IMPACT ASSESSMENT ACT 1992 (N0. 68) (the "EIA ACT")

11.1 The EIA Act deals with the consideration of environmental impact in respect of public and private projects. The application of the EIA Act to the oil and gas industry is seen in its schedule where it makes provisions for specific activities requiring an environmental impact assessment. These activities include, oil and gas development, construction of off-shore pipeline in excess of 50 kilometers in length, construction of refineries, etc.

11.2 By and large, all environmental regulatory power in the oil and gas sector is currently exercised by the Department of Petroleum Resources, which has also issued the Environmental Guidelines and Standards for the Petroleum Industry in Nigeria.

12. PETROLEUM INDUSTRY BILL ("PIB")

12.1 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.

12.2 In 2016, following a 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 Petroleum Industry Fiscal Bill; (iii) the Petroleum Industry Administration Bill; and (iv) the Petroleum Host Community Bill. The Nigerian Senate passed the PIGB on 25 May 2017. On 25 January 2018, the Federal House of Representatives passed the PIGB.

12.3 A harmonised version of the PIGB was subsequently sent to the President of the Federal Republic of Nigeria who refused to assent to the PIGB on the following grounds:

12.3.1 the funding of the Nigerian Petroleum Regulatory Commission through its retention of 10 per cent. of the funds it collects on behalf of the Federal Government was regarded as inordinately high and would deprive the Federal, State and Local Governments of a significant proportion of available revenue;

12.3.2 the PIGB was also said to extend the scope of activities of the Petroleum Equalization Fund (PEF) in contradiction of the policies of the Federal Government; and

12.3.3 drafting inconsistencies.

Of note also is the fact that the House of Representatives passed the Petroleum Industry Fiscal Bill in April 2018. The actions referred to above were all taken in the life of the last parliament and have fallen away following that parliament being prorogued last year. The Federal Government has indicated that it is working on revisions of the four PIB related bills and will introduce the versions again this parliamentary term.

Appendix B

OVERVIEW OF NIGER'S 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, 2007 (Law n°2007-01 dated 31 January 2007, which implementation modalities are provided for in Decree n°2007-082/PRN/MME dated 28 March 2007) and 2017 (Law n°2017-63 dated 14 August 2017, which replaces the Petroleum Code dated 2007; the draft Decree to implement the application of the Petroleum Code dated 2017 was examined and adopted by the Council of Ministers on September 25, 2018).

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 is the National Downstream Oil Company whose main mission is to ensure the purchase, storage and proper distribution of refined products to all parts of the Nigerien territory and export any excess refined production from the SORAZ refinery. SONIDEP also aims to ensure the continuity and security of supplies of Niger in hydrocarbons and derived products, in particular the constitution and management of security reserves. SONIDEP is present in seven (7) of the eight (8) regions of Niger (Agadez, Diffa, Dosso, Maradi, Niamey, Tahoua and Zinder).

The Petroleum Code is enforced by the agents of the General Direction of Hydrocarbons of Ministry of Petroleum, which General Direction is divided into five National Technical Directions:

- the Hydrocarbon Exploration and Production Direction;
- the Hydrocarbon Refining, Transport and Distribution Direction;
- the Environmental Preservation, Health and Safety Direction;
- the Economy and Oil Taxation Direction; and
- the Valuation and Follow up of Petroleum Investments Direction.

Appendix C

SUMMARY OF THE KEY TERMS OF THE SAVANNAH PSCS

R1/R2 and R3/R4 PSCs

1. Exploration and Exploitation Process and Timelines

Below is a description of the process and timelines under the R1/R2 and R3/R4 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 one Exploration Well to a minimum depth of 2,500 metres.
- For the second renewal period, the drilling of one 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 one Exploration Well to a minimum depth of 2,500 metres.
- For the second renewal period, the drilling of one 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[1]; 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.

[1] 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 interpret 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 interest-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 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 pipeline 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 pipeline 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 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 pipeline 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/km^2/year
  Second validity period: 1,500F/km^2/year
  Third validity period: 2,500F/km^2/year
  Extension: 5,000F/km^2/year

  (b) Exclusive Exploitation Authorisation:
  First validity period: 1,500,000F/km^2/year
  Second validity period: 2,000,000F/km^2/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 the 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; and (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; or
- infringe the Contractor's economic and fiscal rights and advantages resulting from Petroleum Legislation and this Contract.

Proposed R1/R2/R4 PSC

1. **Exploration and Exploitation Process and Timelines**

Below is a description of the process and timelines under the proposed R1/R2/R4 PSC for the exploration and exploitation of the Contractual Area governed by the proposed R1/R2/R4 PSC. The proposed R1/R2/R4 PSC shall be subject to the Petroleum Code 2017 (Law n°2017-63 dated 14 August 2017, which replaces the Petroleum Code dated 2007).

Stage 1 – Exploration phase

Pursuant to Article 8.1 of the proposed R1/R2/R4 PSC, the Government shall issue the Contractor an Exclusive Exploration Authorisation via an order by the Minister responsible for Hydrocarbons, 30 days following the signature of the proposed R1/R2/R4 PSC. Pursuant to Article 8.1 of the proposed R1/R2/R4 PSC, the term of the Exclusive Exploration Authorisation shall be four years from the date of issuance, i.e. the date of Official Gazette publication (hereafter referred to as "the Initial Period" of the Issuance Order). Article 8.1.4 of the proposed R1/R2/R4 PSC requires the Contractor to undertake Exploration Operations within 180 days from the date of the award of the Exclusive Exploration Authorization. Failure to comply with such deadline may constitute a default under the proposed R1/R2/R4 PSC and may result in the withdrawal of the Exclusive Exploration Authorisation.

Under Article 8.2 of the proposed R1/R2/R4 PSC, 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 two year extension requested by the Contractor in accordance with Article 10.3 of the proposed R1/R2/R4 PSC (mentioned below)).

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 at the date of the renewal application.

Article 9 of the proposed R1/R2/R4 PSC provides that, during the Initial Period, the Contractor undertakes to execute the following Minimum Works Programme: (i) acquisition, processing and interpretation of 250 km^2 of new 3D seismic profiles; and (ii) drilling of two Exploration Wells to a minimum depth of 2,000 metres.

If a renewal exploration period is granted (each of which is up to two years in length) in respect of proposed R1/R2/R4 PSC, the Contractor shall implement the following Minimum Works Programme:

- For the first renewal period: drilling of two Exploration Well to a minimum depth of 2,000 metres.
- For the second renewal period: the drilling of one Exploration Well to a minimum depth of 2,000 metres.

Under Article 9.5 of the proposed R1/R2/R4 PSC, if the Contractor fails to satisfy the Minimum Works Programme obligation either during the Initial Period or any of the renewal periods, or if due to the total renunciation or the withdrawal of the Exclusive Exploration Authorisation 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: (i) US$1,000,000 for each undrilled well; and (ii) US$2,500 per square kilometer of 3D seismic profiles not acquired, processed or interpreted.

With respect to undertaking Exploration Operations, under Article 35.2.2 of the proposed R1/R2/R4 PSC, the Government acknowledges that a number of environmental studies and environmental compliance certificates previously obtained with respect to the R1, R2 and R4 blocks remain valid for the term of the proposed R1/R2/R4 PSC.

Stage 2 – Discovery/Feasibility phase

Article 10.1 of the proposed R1/R2/R4 PSC provides that the Contractor must notify the Government as soon as possible of any Discovery made within the Contractual Exploration Area and no later than seven days from this Discovery. Within 30 days of the Discovery, the Contractor shall send a report concerning this Discovery to the Minister responsible for Hydrocarbons containing all available information about this Discovery. If the Contractor fails to notify the Government within the seven day period of a Discovery estimated to exceed five million discoverable barrels, the Contractor shall incur a penalty of US$1,000,000.

Under Article 10.2.1 of the proposed R1/R2/R4 PSC, no later than 90 days after the notification of the Discovery and if the Contractor considers that the Discovery indicates the existence of a Commercial Oilfield, the Contractor must undertake a Feasibility Study to confirm the existence of the Commercial Oilfield.

Under Article 10.3, the Contractor can make an application to the Minister responsible for Hydrocarbons to extended the Exclusive Exploration Authorisation for up to an additional two year period in order to enable the Contractor to finalise either: (i) a Feasibility Study for a Discovery; or (ii) a Feasibility Study for the operations of construction and exploitation of a Pipeline Transport System for Hydrocarbons.

Stage 3 – Exploitation phase

Under Article 12.1 of the proposed R1/R2/R4 PSC, 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 12.4 of the proposed R1/R2/R4 PSC, 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 twenty five years with respect to the exploitation of crude oil, and thirty years with respect to the exploitation of natural gas.

Article 12.5 of the proposed R1/R2/R4 PSC provides that the Contractor is entitled to apply for a maximum ten year extension of the period of each Exclusive Exploitation Authorisation. This application for an extension must be submitted at least two years prior to the expiration of the initial period of the Exclusive Exploitation Authorisation. If the extension application is deemed admissible by the Minister responsible for Hydrocarbons, the Minister responsible for Hydrocarbons and the Contractor shall negotiate and agree an amendment to the PSC. Such amendment shall be presented to the Council of Ministers for approval by decree.

Government of Niger participation

Under Article 14.1 of the proposed R1/R2/R4 PSC, on the issuance of any Exclusive Exploitation Authorisation, the Government shall be entitled to require the transfer of a participating interest of up to twenty per cent. in the rights and obligations arising from such Exclusive Exploitation Authorisation either directly to or through the National Operator (a commercial company which is wholly owned by the Republic of Niger and created for the purpose of carrying out Petroleum Operations) (the "Public Participating Interest").

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 14.3 of the proposed R1/R2/R4 PSC):

- Reimburse immediately without interest, its proportional share of the Petroleum Costs relating to the Exploration Operations; and
- Contribute an equivalent amount with the other Joint Holders of the Exclusive Exploitation Authorisation to the financing of the Petroleum Costs relating to the Exploitation Operations from the date of the issuance of the Exclusive Exploitation Authorisation.

Until the commencement date of commercial production, the Government or National Operator shall be carried by the Advances of the other Joint Holders of the Exclusive Exploitation Authorisation up to the Public Participation Interests of fifteen per cent. (the "Carried Participation"). Such Advances shall not be interest bearing. The Government or National Operator shall be responsible for the proportion of costs of the Public Participation Interest which exceed the Carried Participation. From the commencement date of commercial production until complete reimbursement of the Advances, the Government or National Operator shall remit to the Joint Holders the volumes of Hydrocarbons to which it is entitled to the delivery of by way of Cost Oil relating to the Carried Interest.

2. Economics of the PSC

2.1 *Ad Valorem Tax (i.e. Royalty)*

Under Article 40 of the proposed R1/R2/R4 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 proposed R1/R2/R4 PSC).

2.2 *Cost Recovery*

Article 41 of the proposed R1/R2/R PSC 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 Quarter shall be allocated to the reimbursement of: (i) the Petroleum Costs related to Exploitation and Development Operations actually borne by the Contractor in relation to the Contractual Exploitation Area concerned, and (ii) Petroleum Costs related to Exploration Operations, 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 proposed R1/R2/R4 PSC, unrecovered Petroleum Costs in each Calendar Quarter are carried forward to the subsequent Calendar Year until total recovery or expiry of the Contract.

Article 11.2.1 of Annex B of the proposed R1/R2/R4 PSC provides that the recoverable Petroleum Costs related to Exploration Operations expressly includes the following costs:

- A proportion of the signature bonus (to be agreed between Savannah Niger and the Government);
- Historical Petroleum Costs incurred by the Contractor within the framework of the R1/R2 PSC, calculated as at 1st July 2019 equal to US$67,429,000 (which shall be updated to take into account interest accrued thereon calculated in accordance with the terms of the proposed R1/R2/R4 PSC);
- US$2,000,000 to be paid to the State within the framework of the pipeline project for the exportation of Niger crude oil; and
- Amounts paid as contributions towards: (i) training and development; and (ii) legal and financial assistance, under the terms of the proposed R1/R2/R4 PSC.

Article 11.2.3 of Annex B of the proposed R1/R2/R4 PSC provides that the recoverable Petroleum Costs related to Exploitation Operations expressly includes the following costs:

- An amount equal to 60 per cent. of the Exploitation Bonus (the Exploitation Bonus payable by the Contractor shall be dependent on production volumes, and equal to: (i) US$1,000,000 for production volumes less than 5,000 barrels per day; (ii) US$3,000,000 for production volumes greater than or equal to 5,000 barrels per day and less than or equal to 10,000 barrels per day; and (iii) US$5,000,000 for production volumes greater than 10,000 barrels per day (Article 38)); and
- Amounts paid as contributions towards: (i) training and development; and (ii) legal and financial assistance, under the terms of the proposed R1/R2/R4 PSC

Article 11.7 of Annex B of the proposed R1/R2/R4 PSC permits the parent company of the Contractor outside of the Republic of Niger to recover overhead costs up to a cap of the highest of: (i) two per cent. of Petroleum Costs before the overhead costs of the parent company; or (ii) USD$1,000,000.

2.3 ***Profit sharing***

Under Article 42 of the proposed R1/R2/R4 PSC, the Net Production of Hydrocarbons from each Contractual Exploitation Area, less the Ad Valorem Tax and the portion deducted as Cost Oil, is referred to as "Profit Oil" and 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, with the exception of the costs of Development 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 mentioned 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%

For the first Quarter from the commencement of commercial production, the R-Factor shall be deemed to be less than or equal to 1.

2.4 ***Infrastructure***

Pursuant to Article 5.3 of the proposed R1/R2/R4 PSC, 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 pipelines and rights for the construction of pipelines***

Under Articles 7 and 18 and the Annex D of the proposed R1/R2/R4 PSC, the Exclusive Exploitation Authorisation(s) issued to the Contractor shall entitle it 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 the Contractor determines that such transport requires the construction and operation of one or more pipeline transport systems for hydrocarbons, the Government shall, 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; and (2) issue an Internal Transport Authorisation to, the Transport Contractor

The Contractor may also request to be authorised to transport the Hydrocarbons from the Contractual Exploitation Area by a pipeline transport system constructed by another person and in which the Hydrocarbons extracted by the Contractor shall not have priority. The granting of such authorisation shall be automatic if all the conditions required by Petroleum Legislation are met.

The transport tariff relating to a pipeline transport system for Hydrocarbons must be agreed between the Transport Contractor and the Minister responsible for Hydrocarbons. 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; 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.

The State shall facilitate the Contractor to use existing pipeline transport systems for Hydrocarbons or pipelines to be constructed for the evacuation of Hydrocarbons from any exploitation contractual area to the international market. The State shall ensure that the transport tariff applied to the Contractor in such pipeline transport systems is fair, and is not discriminatory compared to the rate applied to other users on comparable terms relating to quality, frequency and flow. In principle, the maximum IRR usually granted by the State to any transport contractor is 12.5 per cent.

Concerning international transportation of hydrocarbons produced, Annex D of the proposed R1/R2/R4 PSC provides 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 36.2 of the proposed R1/R2/R4 PSC provides that on the earlier of:

- when the parties estimate that 50 per cent. of the initial recoverable reserves of an Exclusive Exploitation Authorisation will have been produced at the end of the next Calendar Year; and
- the fifteenth anniversary of the date of granting the Exclusive Exploitation Authorisation,

the Contractor shall submit to the Minister responsible for Hydrocarbons, no later than 31st August of the then current Calendar Year, an abandonment plan. The abandonment plan shall include the Abandonment Operations that the Contractor proposes to execute within the Contractual Exploitation Area relating to the Exclusive Exploitation Authorisation, a plan for the restoration of the site, a programme of the proposed works, and a detailed estimate of all costs associated with the Abandonment Operations. The Contractor shall submit a budget for the abandonment plan, which shall not exceed US$400,000 and shall be deemed a Petroleum Cost.

Under Article 36.3 of the proposed R1/R2/R4 PSC, from the date which is the earlier of:

- the Calendar Year which seventy five per cent. of the initial recoverable reserves of an Exclusive Exploitation Authorisation will be produced; and
- the fifteenth anniversary of the date of granting the Exclusive Exploitation Authorisation,

the Contractor shall pay an annual provision for Abandonment Operations in an account with the Central Bank of West African States, in accordance with the terms of an escrow agreement. The annual provision for the Abandonment Operations to be 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 during the Exclusive Exploitation Authorisation at the beginning of this Calendar Year within the Contractual Exploitation Area in question.

2.7 ***Taxes***

- **Land royalties**

  The Contractor must pay annual land royalties calculated in accordance with the following schedule (in XOF):

  (c) Exclusive Exploration Authorisation:
  Initial Period: 500F/km^2/year
  First Renewal Period: 1,500F/km^2/year
  Second Renewal Period: 2,500F/km^2/year
  Extension period: 5,000F/km^2/year

  (d) Exclusive Exploitation Authorisation:
  Initial Period: 1,500,000F/km^2/year
  Renewal Period: 2,000,000F/km^2/year

- **Capital gains tax on Assets Transfer**

  Pursuant to Article 48.1 of the proposed R1/R2/R4 PSC, the capital gains resulting from the transfer of an Authorisation or a participation in any such Authorisation realised by the Contractor or any of its constituent entities shall be subject to an exceptional 25 per cent. tax payable by the Assignor.

  Under Article 48.2 of the proposed R1/R2/R4 PSC, 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 proposed R1/R2/R4 PSC, the basis for the capital gains tax shall be the difference between:

  - the transfer price for the assets concerned; 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 repayment of advances made by the Assignee in relation to the Authorisation concerned (a "Payment in Kind"). Pursuant to Articles 48.2.3 and 48.2.4 of the proposed R1/R2/R4 PSC, notwithstanding the provisions above, the financial valuation of the Exploration Operations that the Assignee agrees to perform on behalf of the Contractor is not included in the sale price of the assets, provided that the relevant Exploration Operations are conducted after the date of the transfer. 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 aggregate Petroleum Costs relating to these assets not yet recovered but actually incurred by the Contractor as at the date of transfer. For the purpose of calculating the cost price, such Petroleum Costs shall be deemed to include costs directly incurred in relation to the Petroleum Operations before the date of entry into the PSC, including costs incurred for the purpose of negotiating and signing the PSC and the signature bonus amount.

Pursuant to Article 48.3 of the proposed R1/R2/R4 PSC, the capital gains tax shall be paid by the Assignor:

- if the sale price is paid entirely by any mean other than a Payment in Kind, within thirty days of the issue of the transfer authorisation;
- if the sale price is paid partly by cash and partly by Payment in Kind and;
  - the difference between the cash payment and the cost price of the transferred Authorisation or participation in an Authorisation or participation in an Authorisation results in a positive balance:
    - the capital gains tax on the positive balance shall be paid within thirty days of the issue of the transfer authorisation; and
    - the remaining balance of capital gains shall be payable no later than 31 March of the Calendar Year following the Calendar Year in which the Cost Oil corresponding to the Petroleum Costs (the "Cost Oil Nature Payment") is paid to the Contractor, up to a limit of 25 per cent. of the amount of Cost Oil, until full repayment of the capital gain tax amount.
  - the difference between the cash payment and the cost price of the transferred Authorisation or participation in an Authorisation results in a negative or net zero balance, the capital gains tax shall be payable from the first year which the Cost Oil Nature Payment is made to the Contractor, up to a limit of 25 per cent. of the amount of Cost Oil, until full repayment of the capital gain tax amount.

The transfer of the Authorisation or participation in an Authorisation concerned shall only take effect from the submission of a declaration by the Contractor concerning the capital gain on the disposal, validated by the tax authorities of the Republic of Niger, and of the payment of the tax due.

Under Article 48.4 of the proposed R1/R2/R4 PSC, any capital gains realised on the disposal of an Authorisation or a Participation in an Authorisation to an affiliated company shall benefit from the deferment of the capital gains tax until any subsequent disposal by the affiliate entity to a third party (including the capital gain tax due on such disposal to the third party).

- **General tax exemption**

  Pursuant to Article 49.1.1 of the proposed R1/R2/R4 PSC, apart from the fees stipulated in Article 90 of the Petroleum Code, the exceptional capital gains tax on disposals under Article 48, 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), the tree cutting tax and the provisions of Paragraph 49.4 of the proposed R1/R2/R4 PSC 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 proposed R1/R2/R4 PSC; or
  - by virtue of the payments received or effected as part of the execution of the proposed R1/R2/R4 PSC.

- **Tax scheme for Transport Operations**

  Annex D of the proposed R1/R2/R4 PSC provides that, in addition to the tax advantages provided under the Petroleum Code, the Transport Contractor will be classified under the regime of free zones or free points provided for under Article 31 of the Investment Code and therefore will benefit from tax and customs exemptions, including the following:

- during the establishment phase:
  - total exemption from duties and taxes collected by the State including value-added tax on services, works and services directly related to Transport Operations; and
  - total exemption from customs duties and taxes, including value-added tax, excluding the Statistical Tax, the Community Levy, the Solidarity Community Levy on imported materials, equipment and tools directly related to Transport Operations.
- during the exploitation phase:
  - total exemption from customs duties and taxes, excluding the Statistical Tax, the Community Levy, the Solidarity Community Levy and the value-added tax on imported raw materials and packaging in case of unavailability of locally produced equivalent products; and
  - total exemption from the minimum tax, the professional tax and the property tax.

2.8 ***Exchange regulations***

Under Article 52 of the proposed R1/R2/R4 PSC and the 2017 Petroleum Code, the Contractor is subject to the exchange control regime under ordinary law in force in the Republic of Niger, which shall include the Western Africa Economic Monetary Union Foreign Exchange Regulation n°09/2010/CM/UEMOA (the "WAEMU FOREX Regulation"). The Contractor shall not benefit from the derogations and exceptions to the Republic of Niger's exchange control regime provided under the R1/R2 PSC and R3/R4 PSC. Under applicable law, Savannah Niger shall be entitled to receive abroad the proceeds of Hydrocarbons effected in the Republic of Niger, but such proceeds must be repatriated to Niger within 30 days from the payment due date under the relevant sales agreement.

Post-repatriation, Savannah Niger shall have the right to transfer funds abroad in accordance with the framework provided under the WAEMU FOREX Regulation, which includes by way of dividend payments and interest payments.

2.9 ***Other fees***

Under the terms of the proposed R1/R2/R4 PSC, the Contractor is obliged to pay the following:

- **Training and Development fees** – the Contractor shall contribute the following towards the training and upgrading of the employees of the Ministry responsible for Hydrocarbons:
  - for each Calendar Year until the end of the Exclusive Exploration Authorisation, up to €250,000; and
  - for each Calendar Year upon the granting of the Exclusive Exploitation Authorisation (and for each Exclusive Exploitation Authorisation), up to €300,000.
- **Legal and financial assistance fees** – the Contractor shall contribute the following towards the financing of legal and financial assistance for the Ministry responsible for Hydrocarbons:
  - for each Calendar Year until the end of the Exclusive Exploration Authorisation , up to €250,000; and
  - for each Calendar Year upon the granting of the Exclusive Exploitation Authorisation (and for each Exclusive Exploitation Authorisation), up to €300,000.
- **Social programme fees** – for assistance to local populations, for each year during the exploration phase, the Contractor shall contribute US$30,000.
- **Municipal Development Petroleum Program ("MDPP")** – Prior to submitting an application for an Exclusive Exploitation Authorisation, the Contractor must submit to the mayor of each municipality concerned, and gain the approval of the municipal council, of a MDPP setting out the Contractor's proposals for financial and technical support for the implementation of the Municipal Development Plan. The amount due from the Contractor for all MDPP (to be distributed equally) shall be:
  - US$150,000 per year, for production volumes less than or equal to 10,000 barrels per day;
  - US$300,000 per year for production volumes greater than 10,000 barrels per day and less than or equal to 50,000 barrels per day; and

- US$1,000,000 per year for production greater than 50,000 barrels per day.

- **Regional Development Petroleum Program ("RDPP")** – Prior to submitting an application for an Exclusive Exploitation Authorisation, the Contractor must submit to the president of each municipality concerned, and gain the approval of the municipal council, of a RDPP setting out the Contractor's proposals for financial and technical support for the implementation of the Municipal Development Plan. The amount due from the Contractor for all RDPP (to be distributed equally) shall be:
  - US$100,000 per year, for production volumes less than or equal to 10,000 barrels per day;
  - US$200,000 per year for production volumes greater than 10,000 barrels per day and less than or equal to 50,000 barrels per day; and
  - US$500,000 per year for production greater than 50,000 barrels per day.

2.10 ***Liability***

Pursuant to Article 6.5 of the proposed R1/R2/R4 PSC, within the limits of and in accordance with the modalities stipulated by the proposed R1/R2/R4 PSC relating to the Contractor's liability 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 proposed R1/R2/R4 PSC.

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 purpose of this Article, 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 Article shall also apply to direct damage to the environment as soon as the damage exceeds the environmental impact level generally accepted in the international petroleum industry and by Current Legislation.

2.11 ***Applicable Law***

Pursuant to Article 58.1 of the proposed R1/R2/R4 PSC, the Petroleum Legislation, Current Legislation (which includes any law or Act with the same legal value, derived from an international treaty or agreement properly ratified by the State) 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; and (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 PSC, its intention to be bound by these rules.

Under Article 58.2 of the proposed R1/R2/R4 PSC, save with respect to amendments to Current Legislation or the Petroleum Legislation relating to the protection of the environment and cultural heritage (provided that such amendments do not create a burden on the Contractor greater than that typically imposed in the international petroleum industry), 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, Current Legislation or of the PSC immediately or in the future; or
- infringe the Contractor's economic and fiscal rights and advantages resulting from Petroleum Legislation, Current Legislation and the PSC.

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