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.

Within this report, CGG makes no representation or warranty as to: (i) the amounts, quality or deliverability of reserves of oil, natural gas or other petroleum; (ii) any geological, geophysical, engineering, economic or other interpretations, forecasts or valuations; (iii) any forecast of expenditures, budgets or financial projections; (iv) any geological formation, drilling prospect or hydrocarbon reserve; (v) the state, condition or fitness for purpose of any of the physical assets, including but not limited to well, operations and facilities related to any oil and gas interests or (vi) any financial debt, liabilities or contingencies pertaining to the organisation, Savannah Energy PLC.

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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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 Group's website in accordance with 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: BP510				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
01	30 April 2020	RC/PW	AW	Final

Date	Originator	Checked & Approved
Signed:		

Prepared for:	Prepared By:
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Table of contents

Figures

Tables

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.

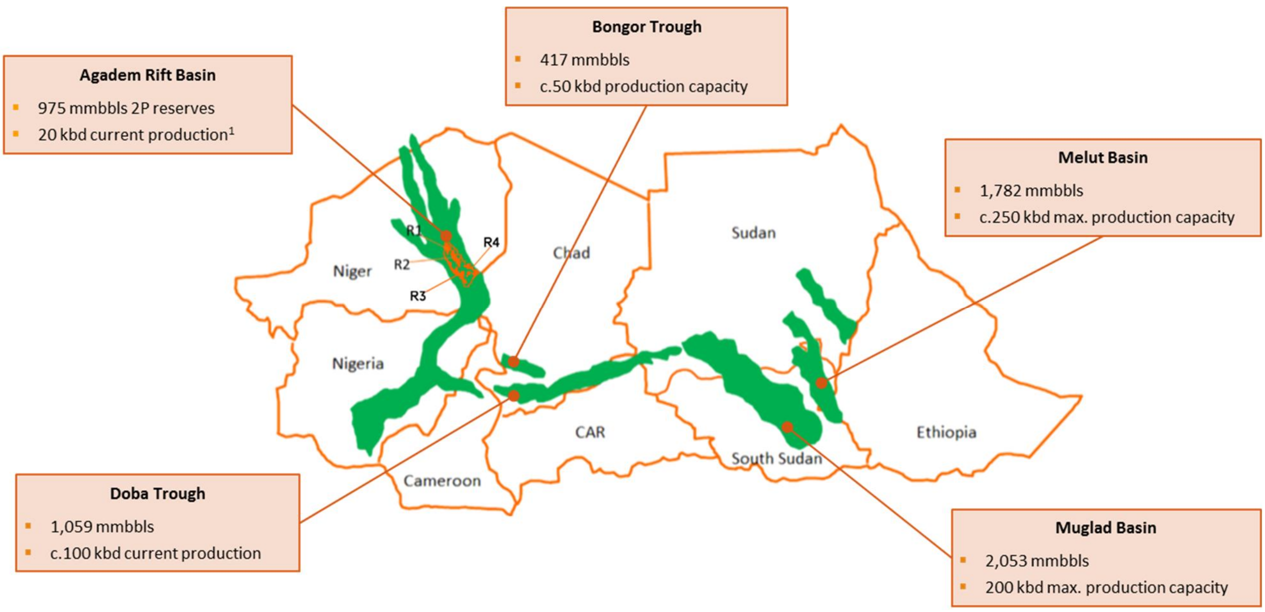

Figure 1-1 The Central African Rift System Discovered Resources (*Source: Savannah, 2017*)

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.

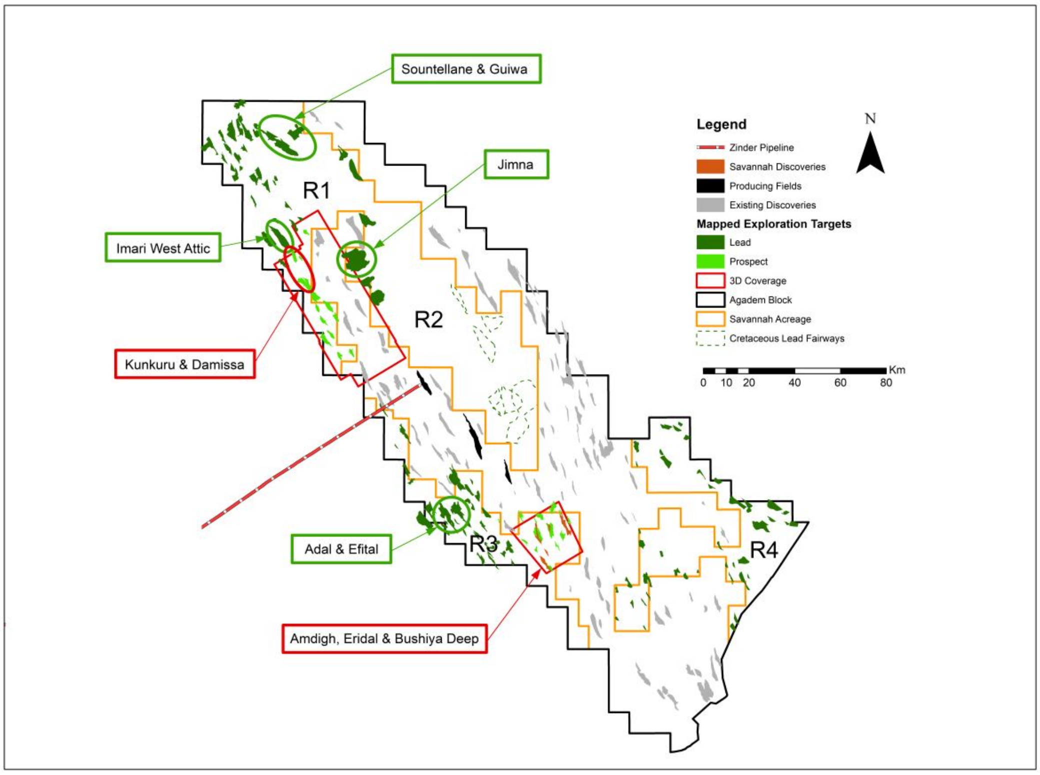

Figure 1-2 Savannah's Prospects and Leads Portfolio (*Source: Savannah, 2019*)

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.

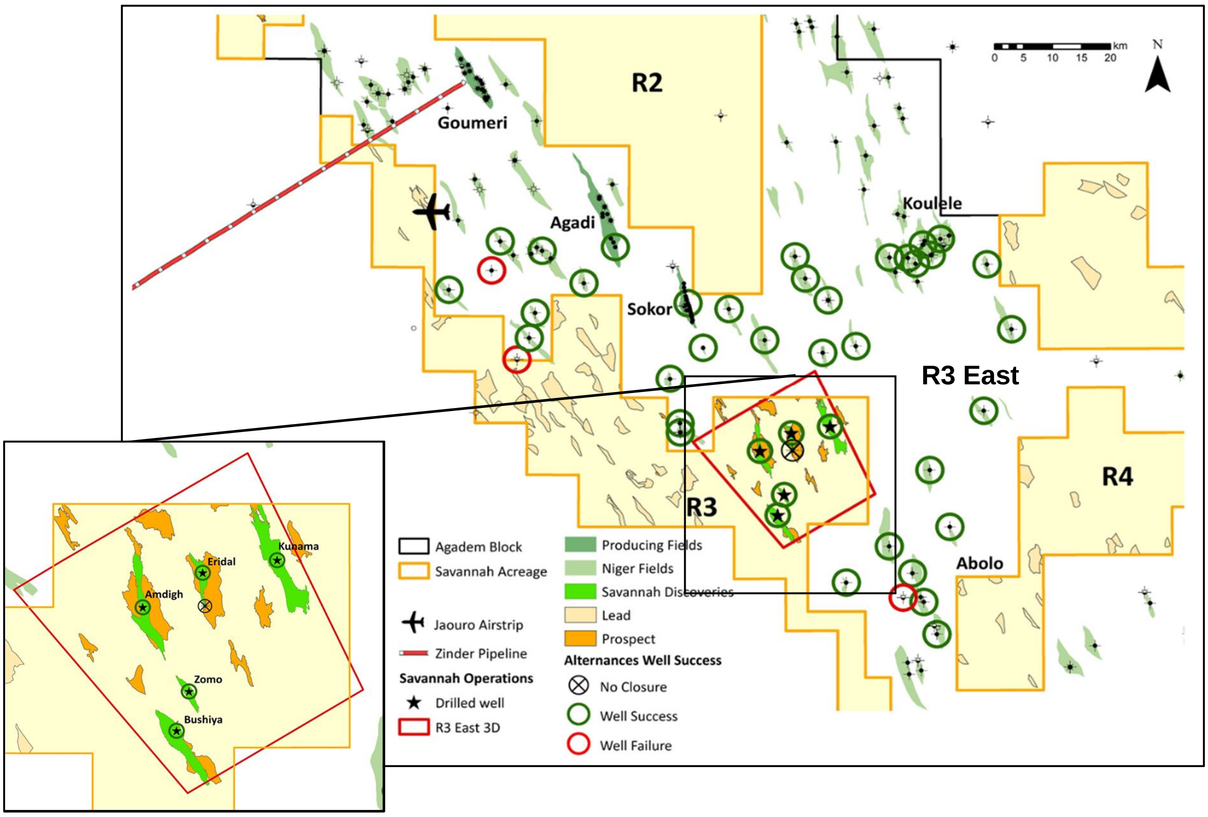

Figure 1-3 Map showing the location of the five 2018's discoveries (*Source: Savannah, 2019*)

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.

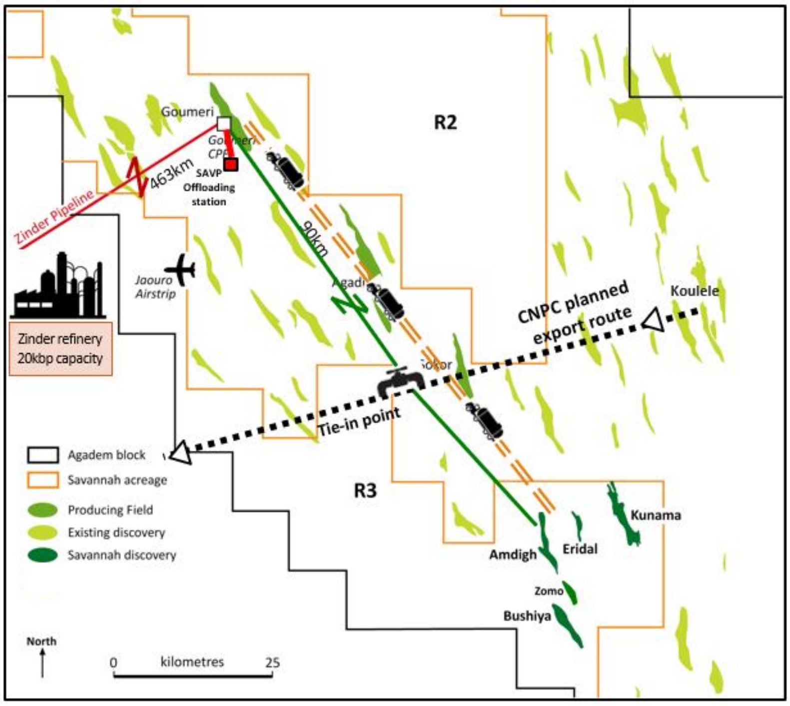

Figure 1-4 Proposed Early Production Scheme Development *(Source: Savannah, 2019)*

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**.

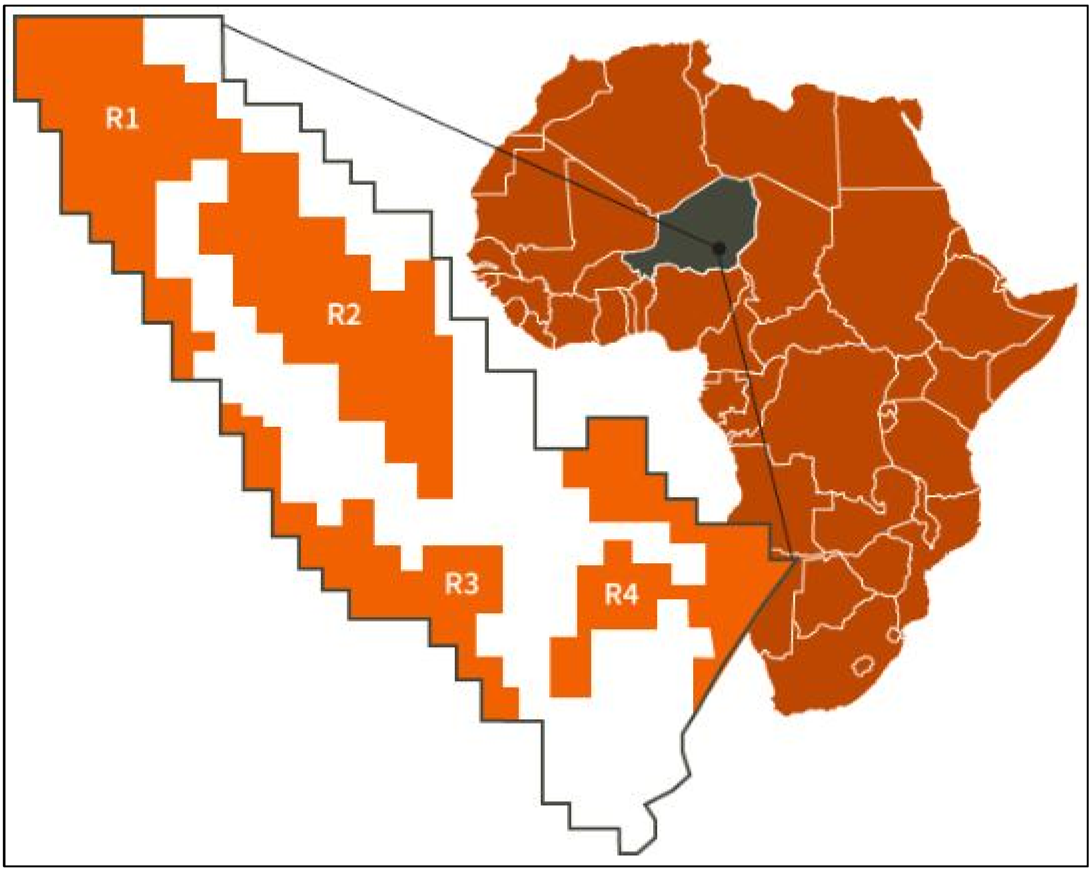

Figure 2-1 Map showing location of the assets (*Source: Savannah, 2017*)

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.

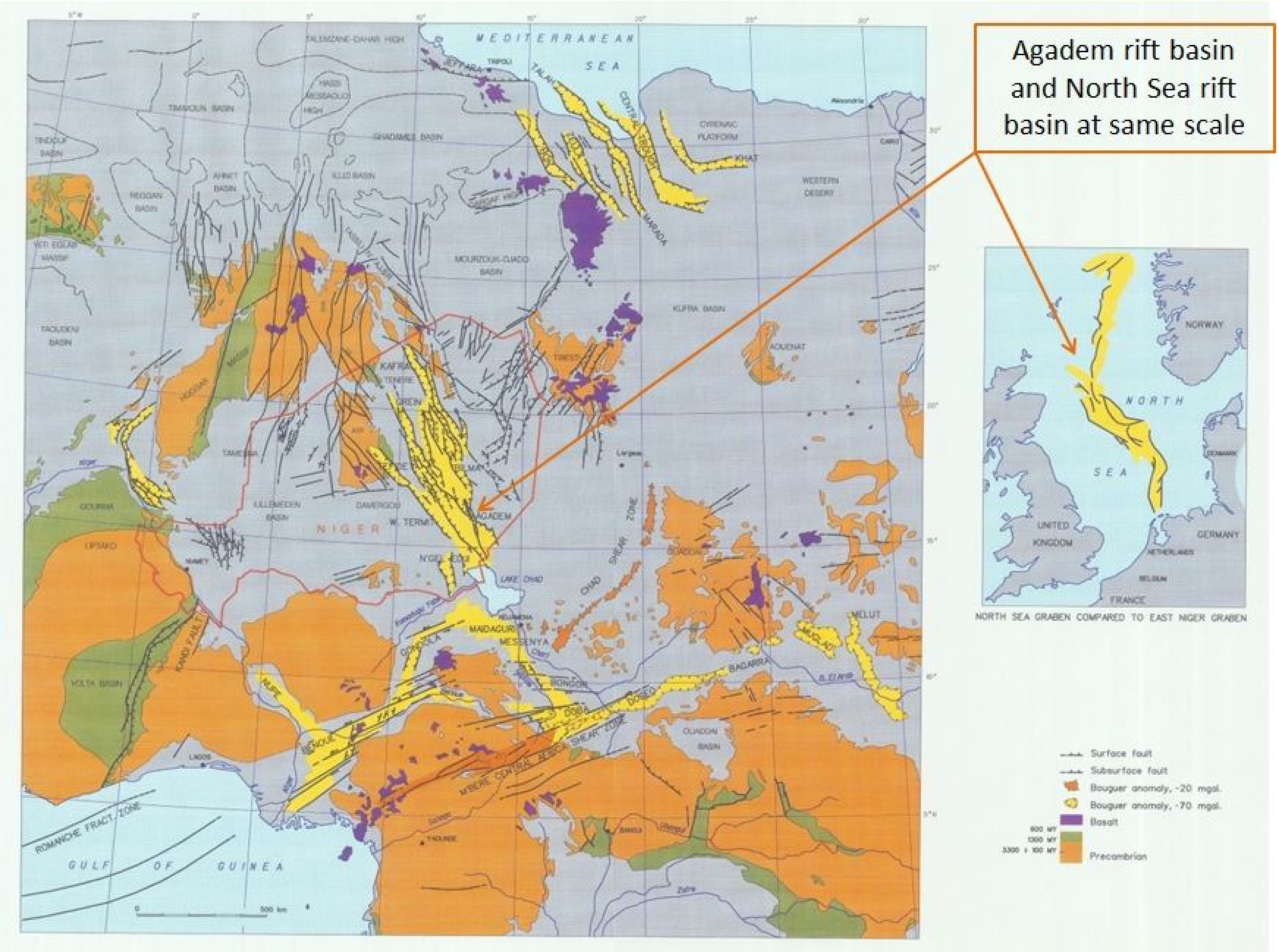

Figure 2-2 Map comparing magnitudes of the basins of Niger and the North Sea

(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**).

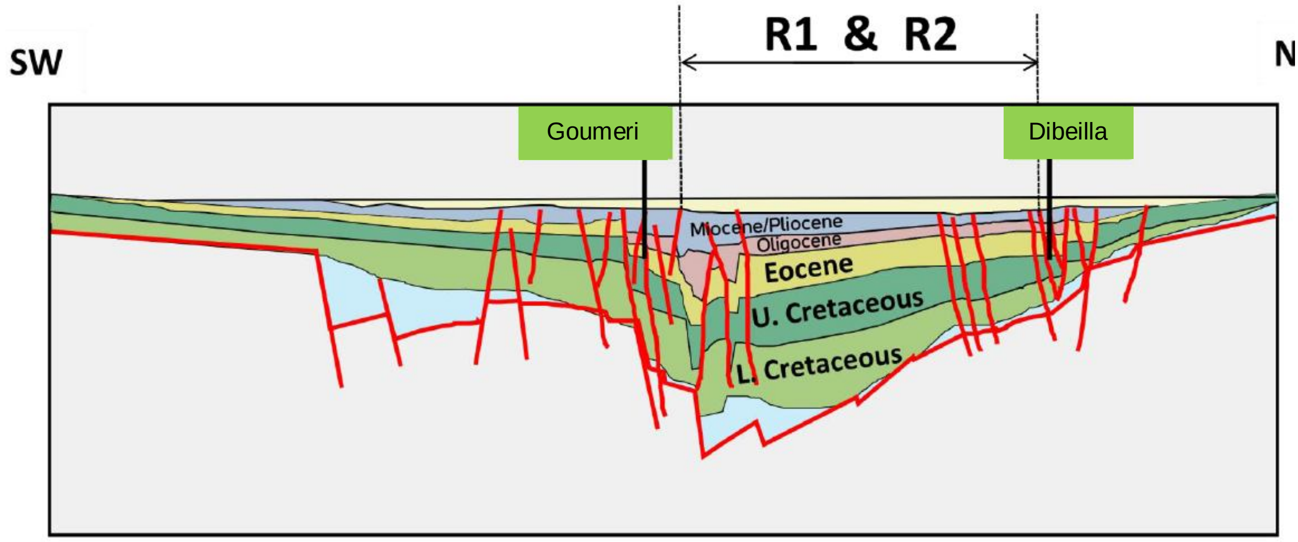

Figure 2-3 Schematic South-West to North-East Cross-Section through the Agadem Rift Basin, Niger

(Source: Niger Ministry of Energy & Petroleum and Savannah, 2017)

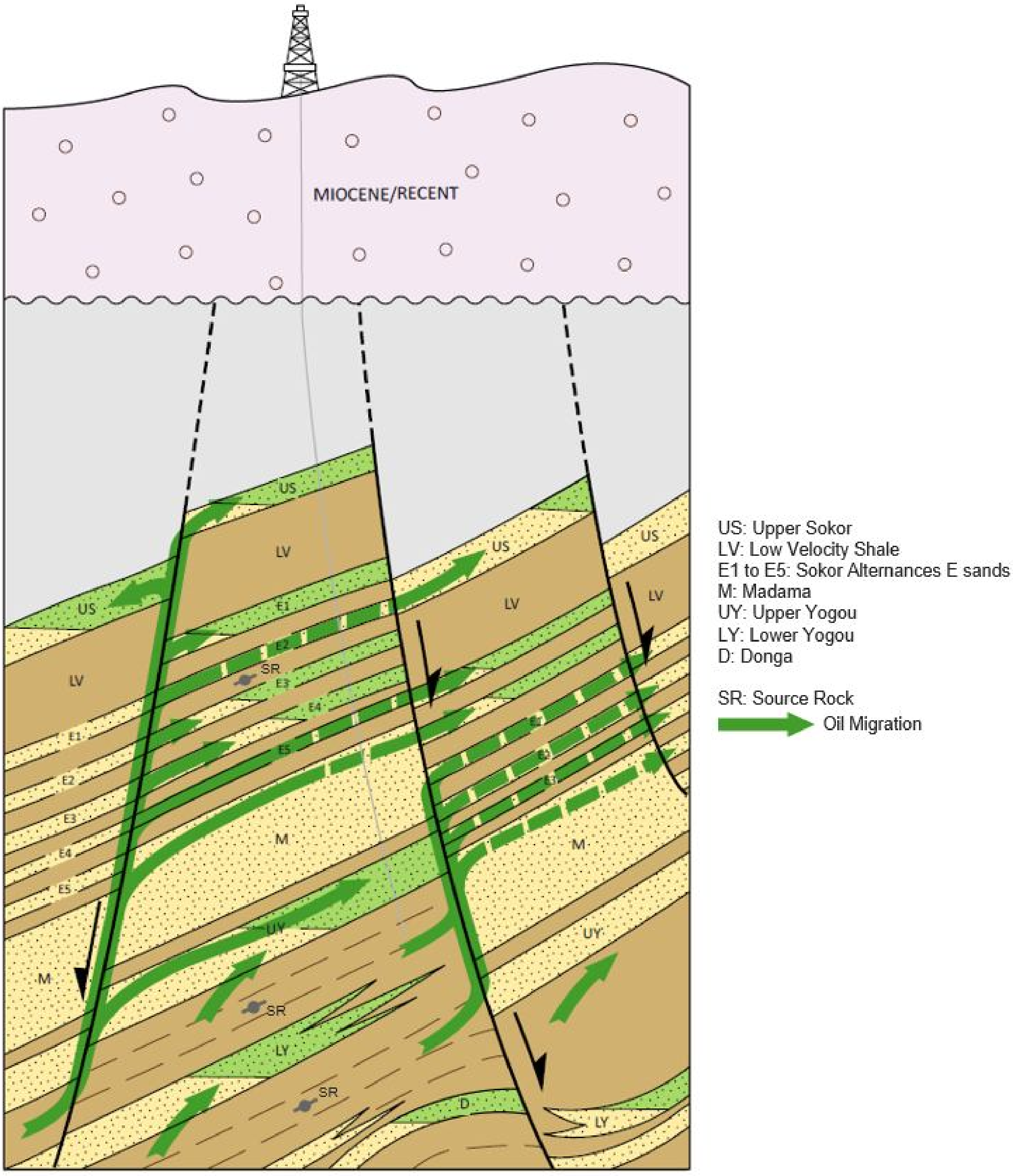

Figure 2-4 Schematic South-West to North-East cartoon cross-section to illustrate the main trapping and charging mechanisms in the Agadem Rift Basin *(Source: Savannah, 2019)*

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.

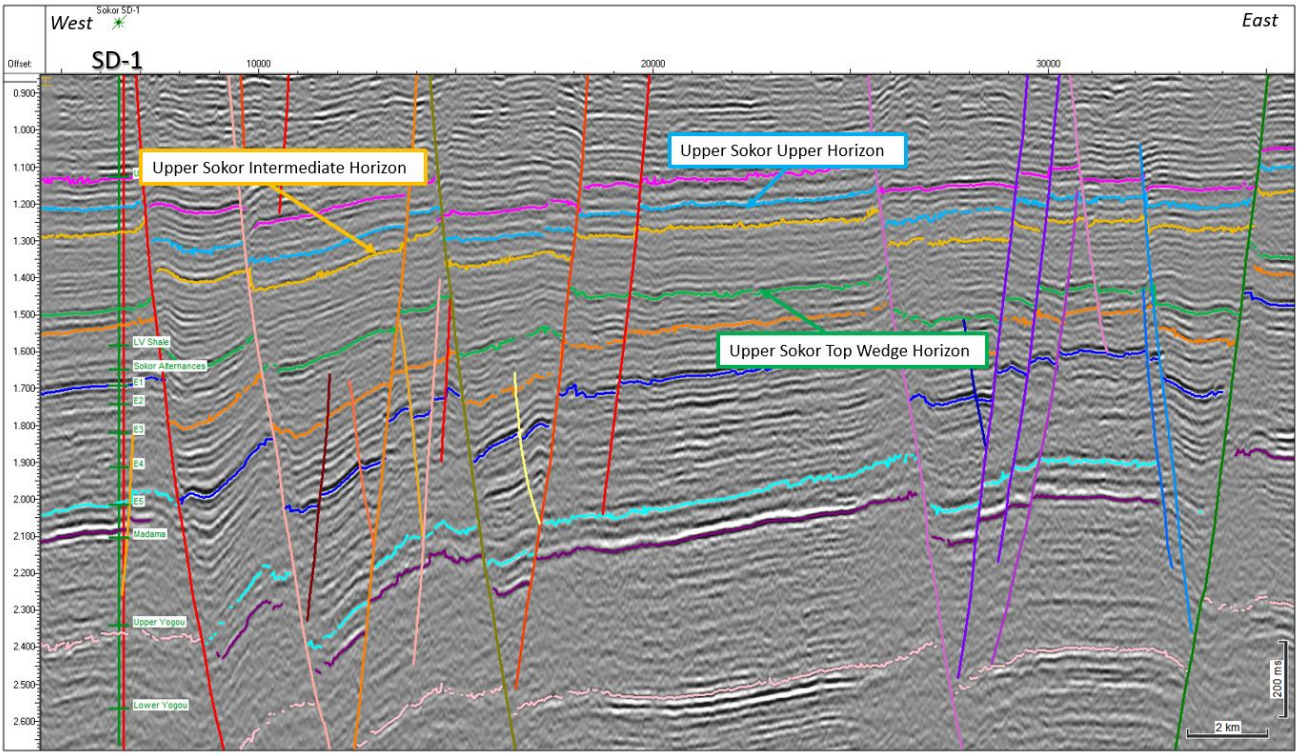

Figure 3-1 W-E 3D seismic profile through Sokor SD-1 well, in the R3 East 3D (*Source: Niger CPR 2017*). The Upper Sokor contains variable amplitudes within a subtle sedimentary wedge above the LV Shale (green to orange markers)

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**).

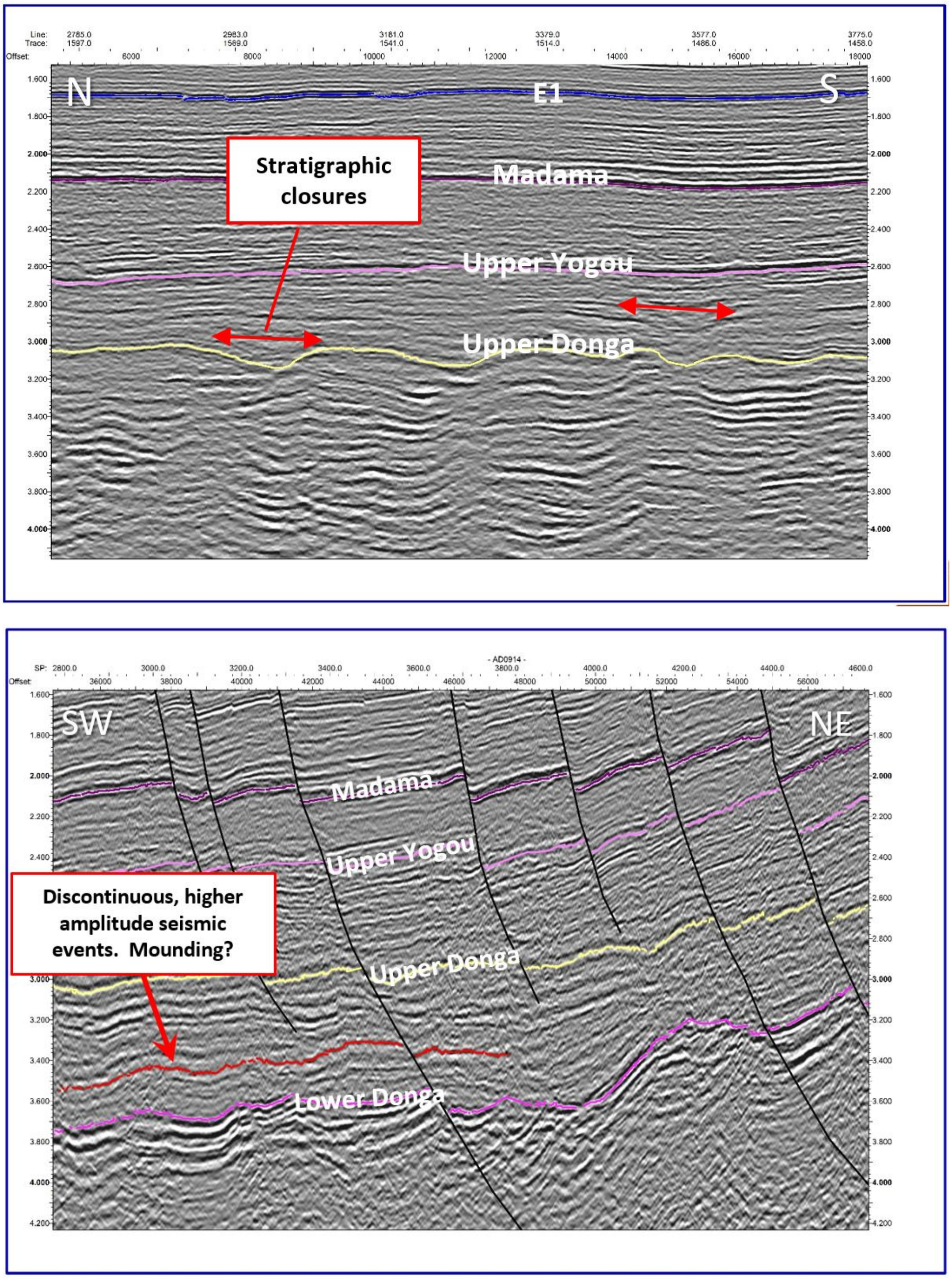

Figure 3-2 Structures at the Lower Yogou and Donga levels – Top: Arbitrary line within the R3 East 3D seismic survey Bottom: 2D seismic line within the R4 area *(Source: Savannah, 2019)*

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**).

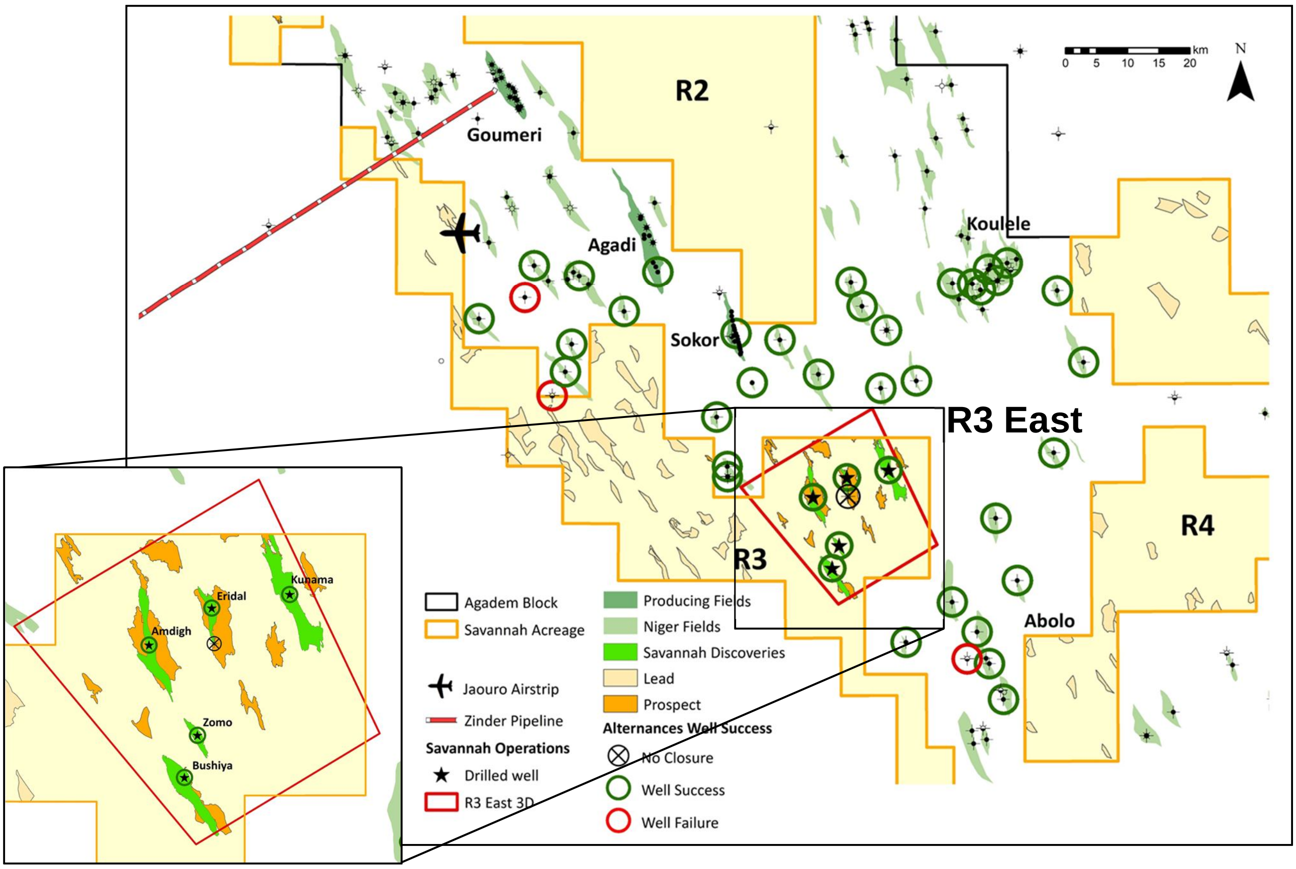

Figure 3-3 Location map of discoveries within the R3 East 3D survey ***(red polygon, source: Savannah, 2019)***

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**).

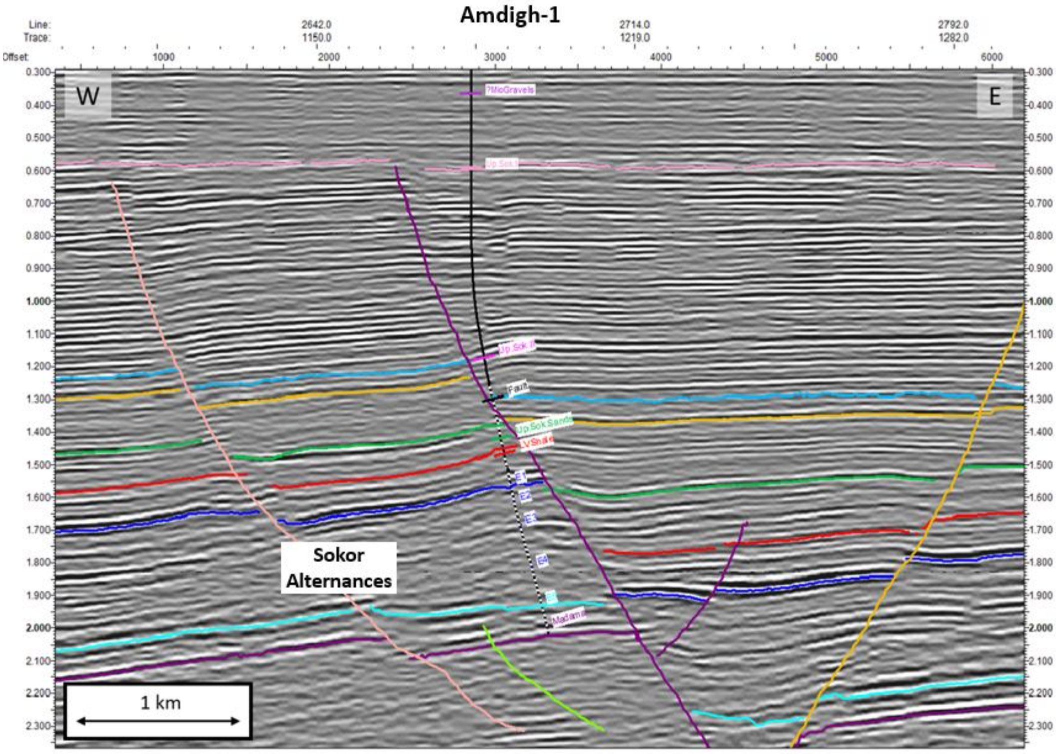

Figure 3-4 PSTM Seismic Section through the Amdigh-1 discovery well *(Source: Savannah, 2019)*

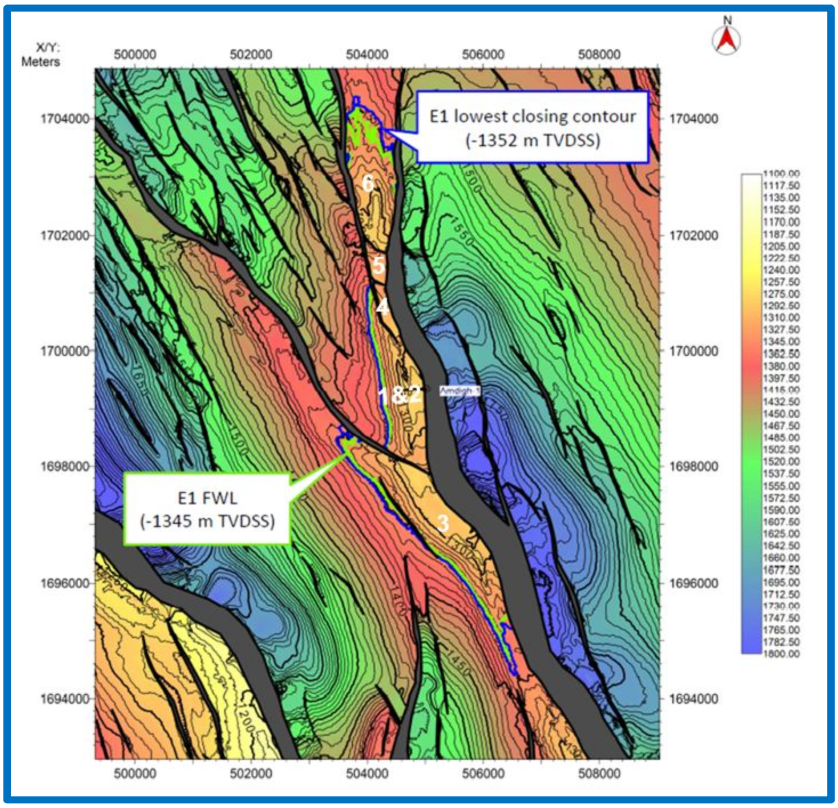

Figure 3-5 Amdigh E1 structural depth map (based on PSTM dataset) and the six segments *(Source: Savannah, 2019)*

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.

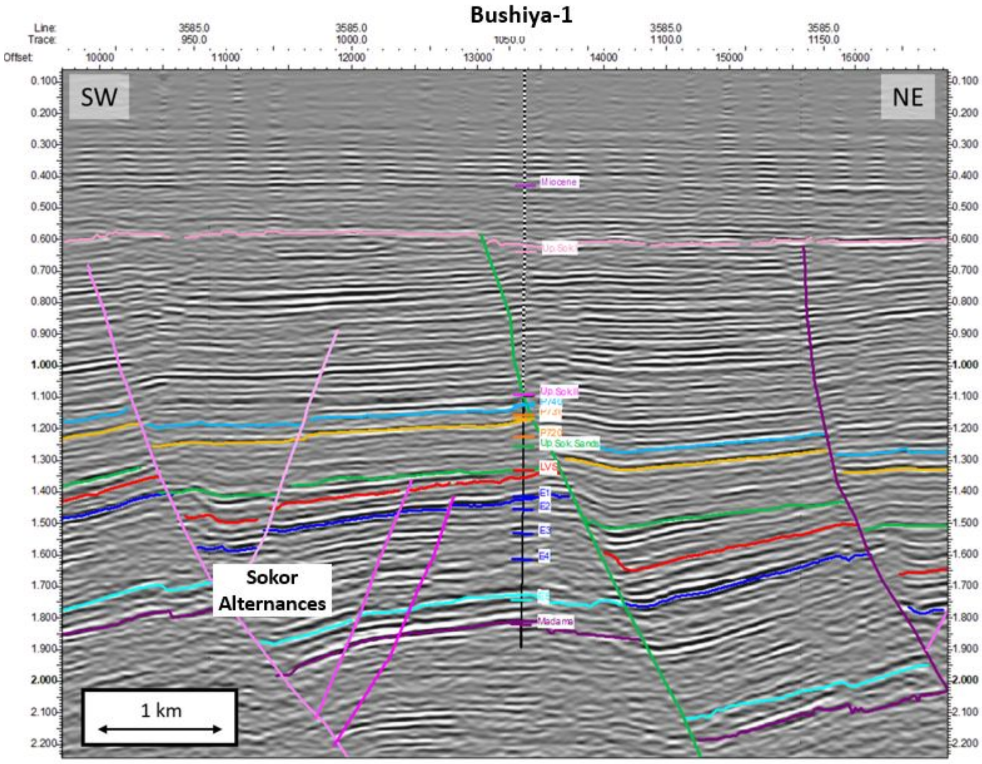

Figure 3-6 PSTM Seismic Section through Bushiya-1 discovery well ***(Source: Savannah, 2019)***

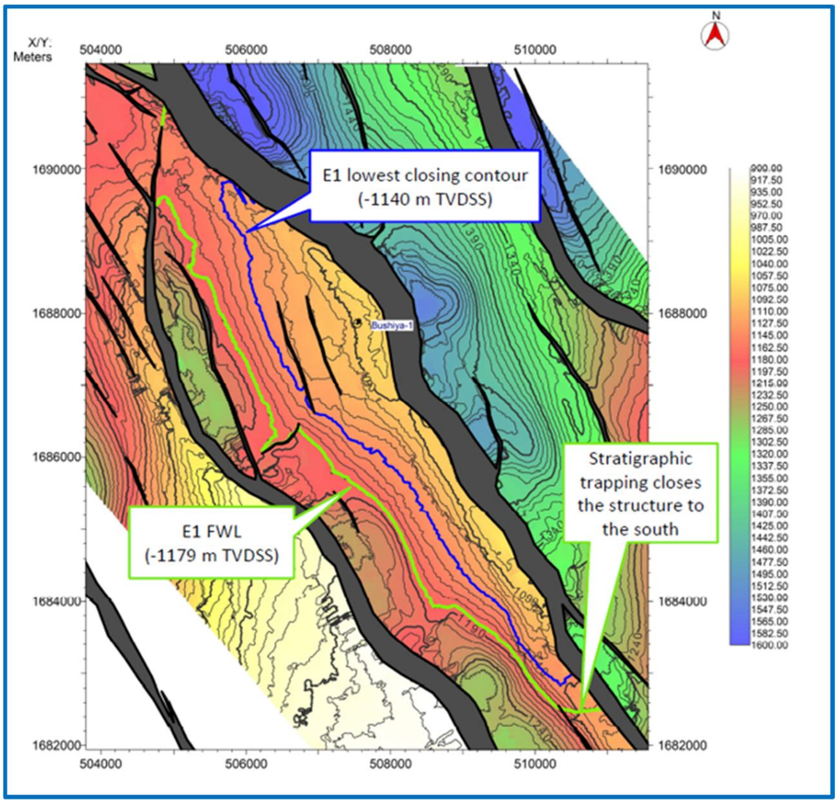

Figure 3-7 Bushiya E1 structural depth map ***(based on PSTM dataset, source: Savannah, 2019)***

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.

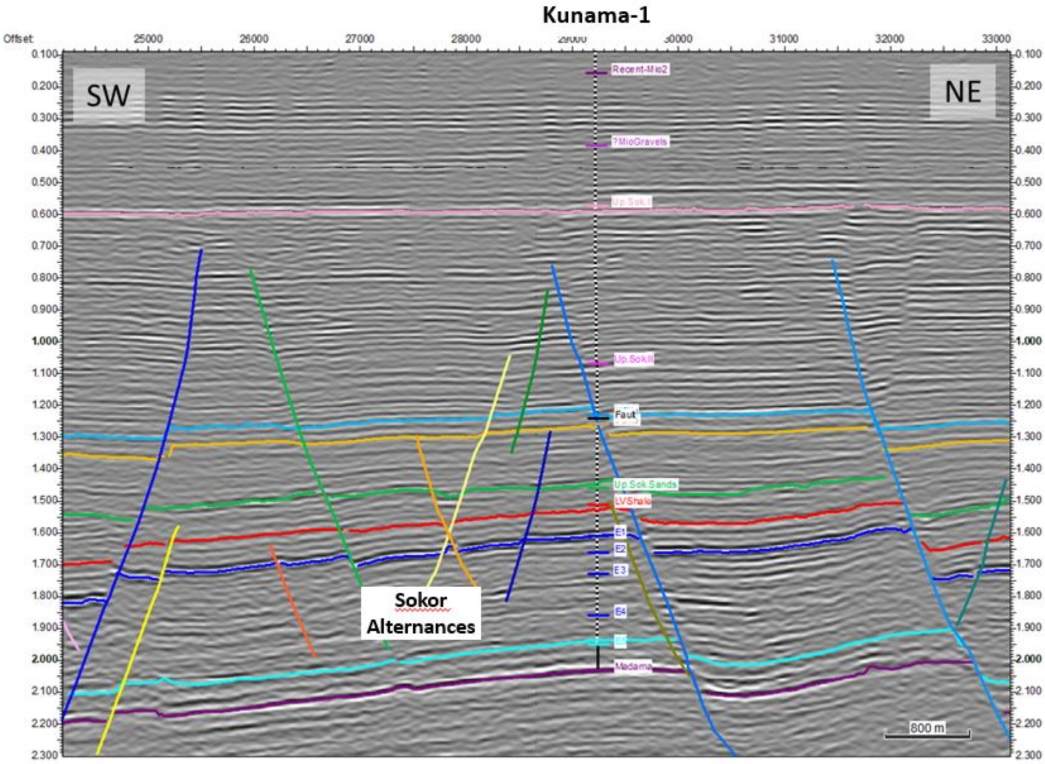

Figure 3-8 PSTM Seismic Section through discovery well Kunama-1 ***(Source: Savannah, 2019)***

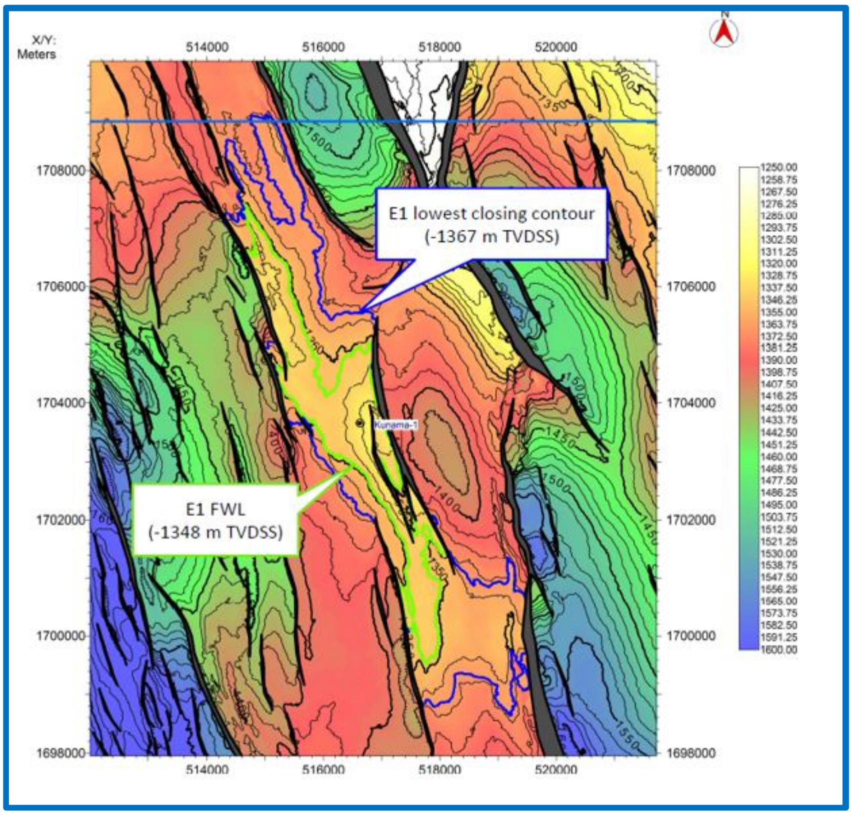

Figure 3-9 Kunama E1 structural depth map ***(based on PSTM dataset, source: Savannah, 2019)***

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.

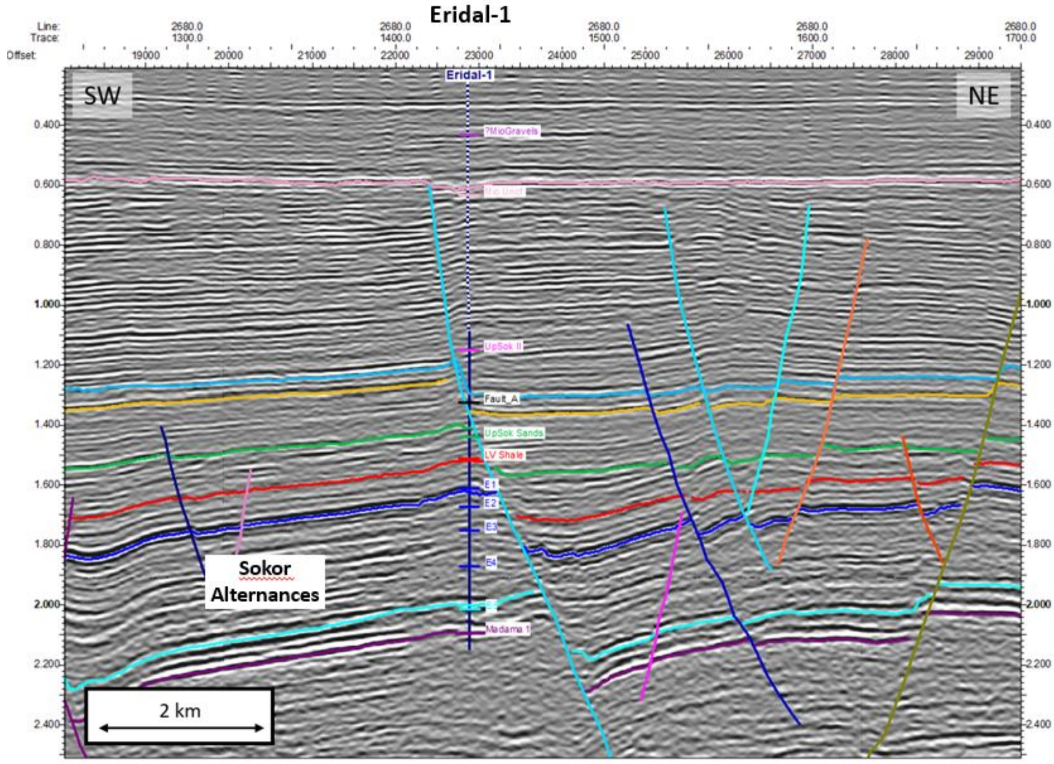

Figure 3-10 PSTM Seismic Section through Eridal-1 discovery well ***(Source: Savannah, 2019)***

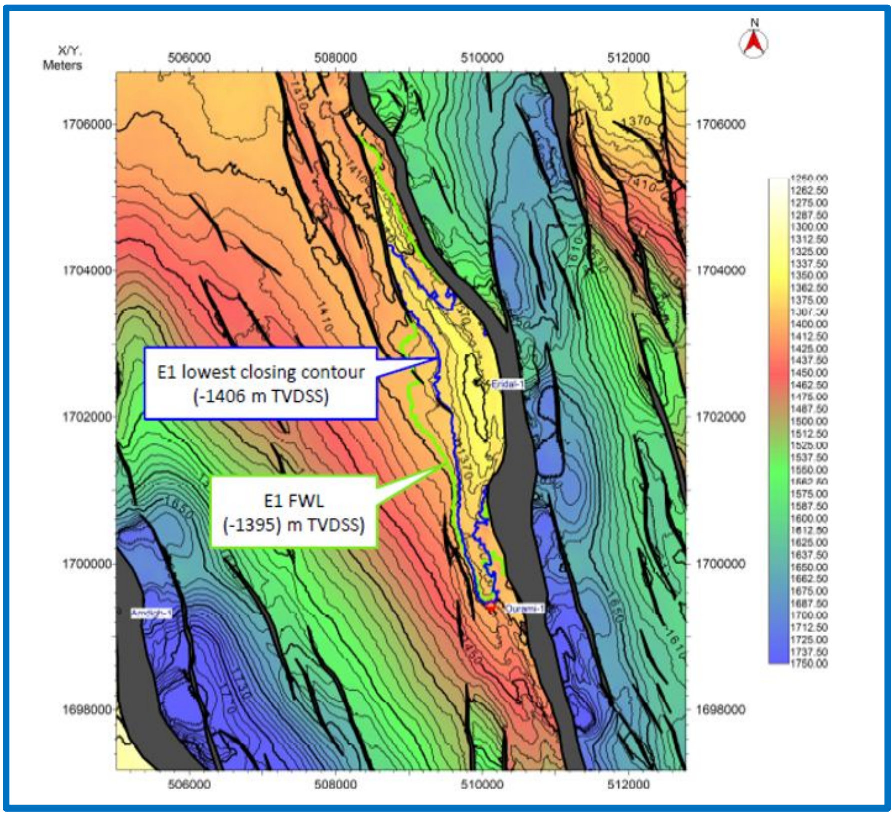

Figure 3-11 Eridal E1 structural depth map ***(based on PSTM dataset, source: Savannah, 2019)***

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.

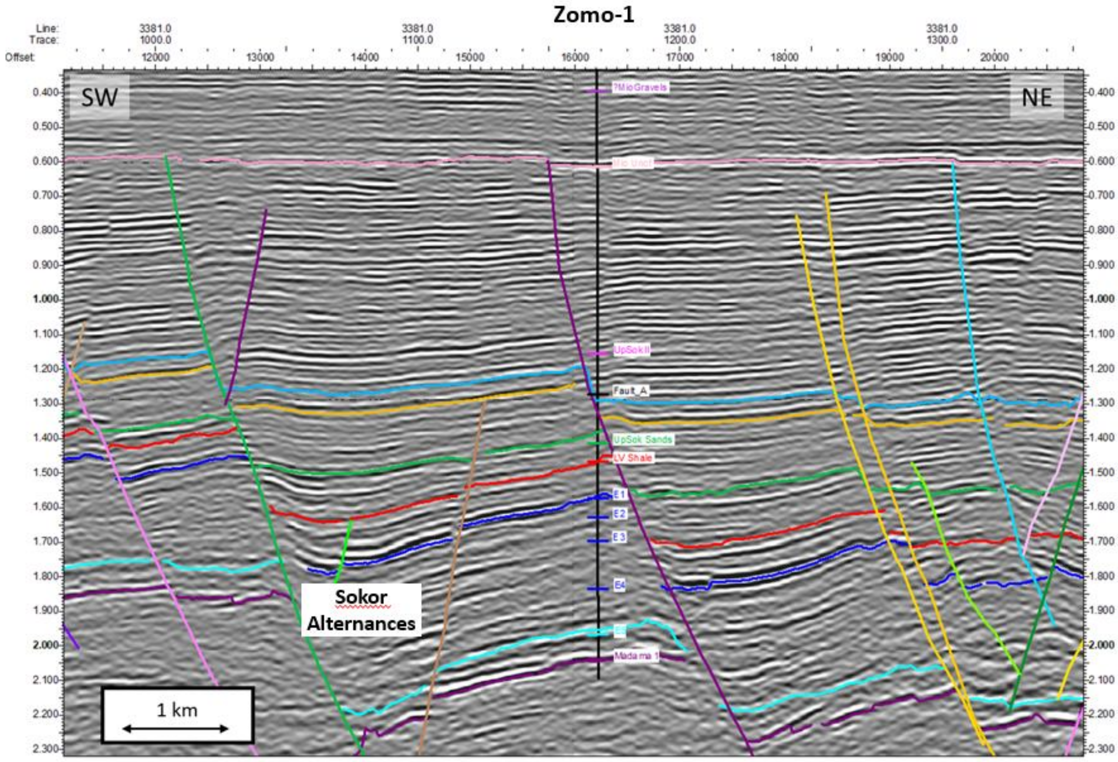

Figure 3-12 PSTM Seismic Section through Zomo-1 discovery well ***(Source: Savannah, 2019)***

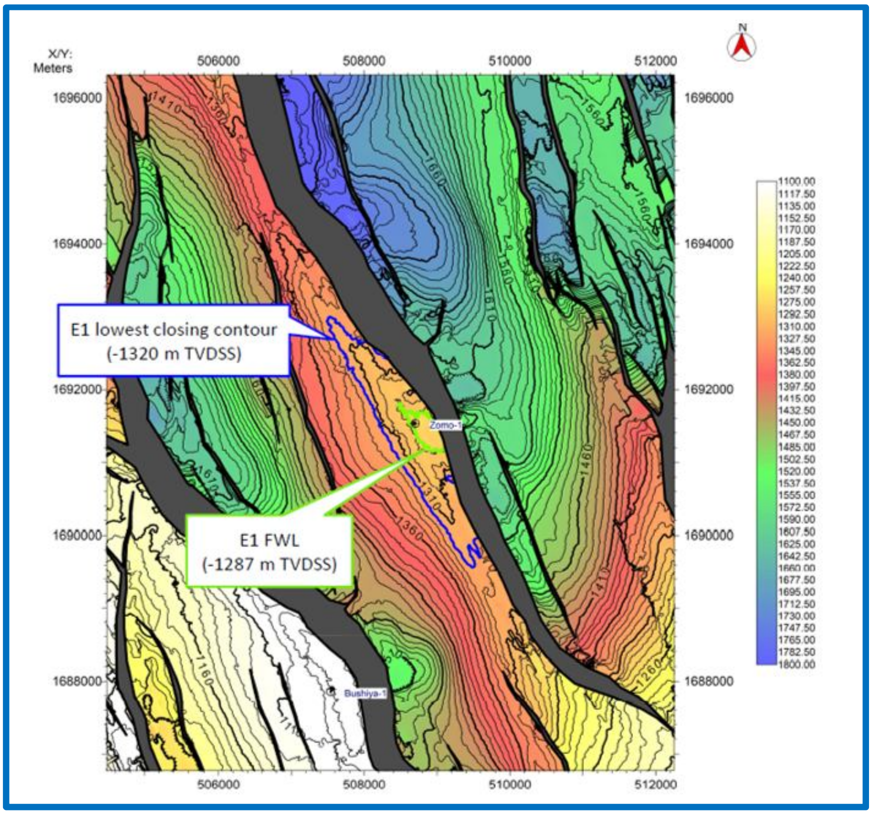

Figure 3-13 Zomo E1 structural depth map ***(based on PSTM dataset, source: Savannah, 2019)***

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.**

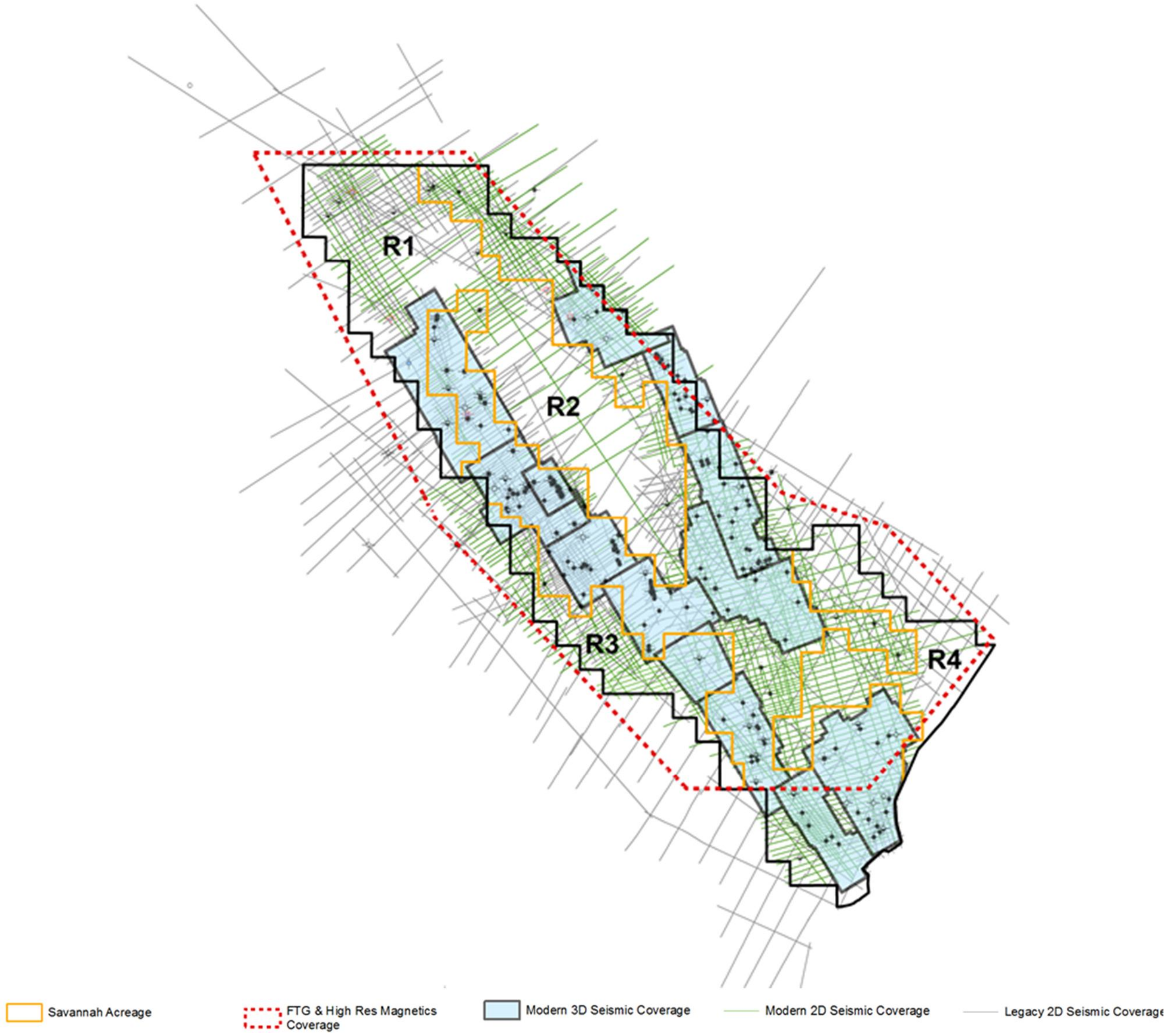

Figure 3-14 Seismic coverage in the Agadem Rift Basin ***(Source: Savannah, 2019)***

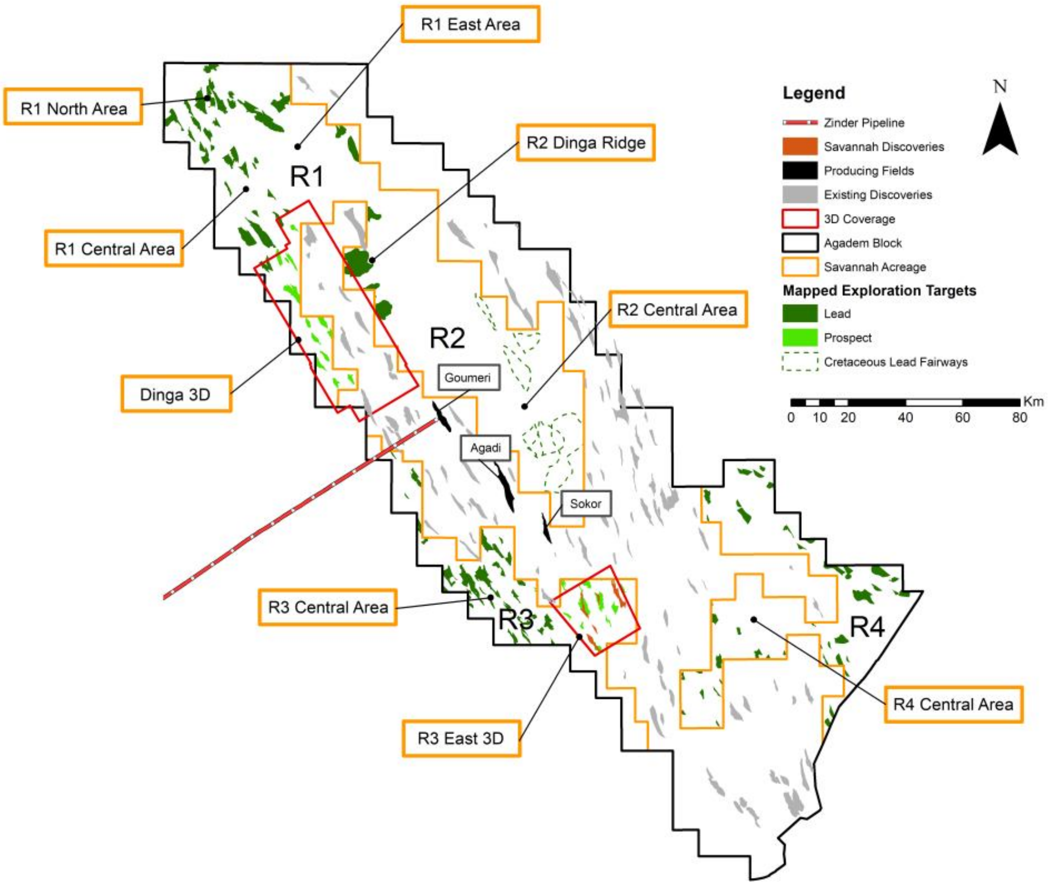

Figure 3-15 Savannah Prospects and Leads Portfolio with discovered fields and relevant 3D surveys (*Source: Savannah, 2019*)

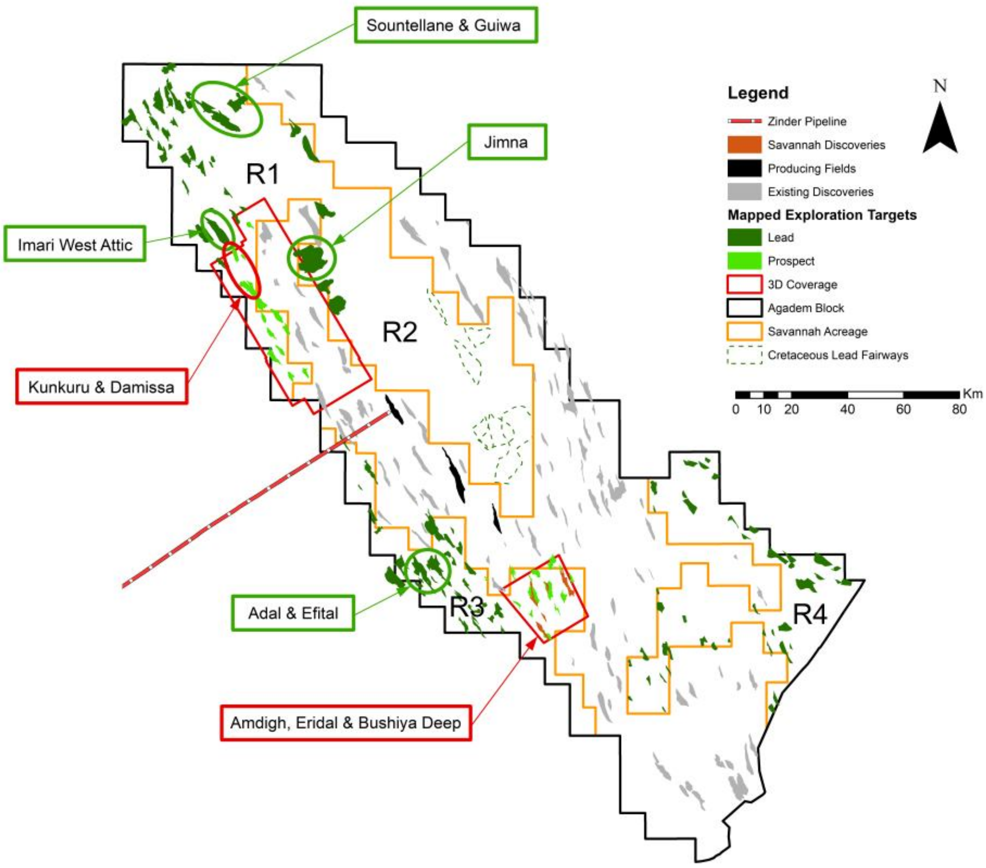

Figure 3-16 Map showing Prospects and Leads assessed by CGG (*Source: Savannah, 2019*)

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/cm^3	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.

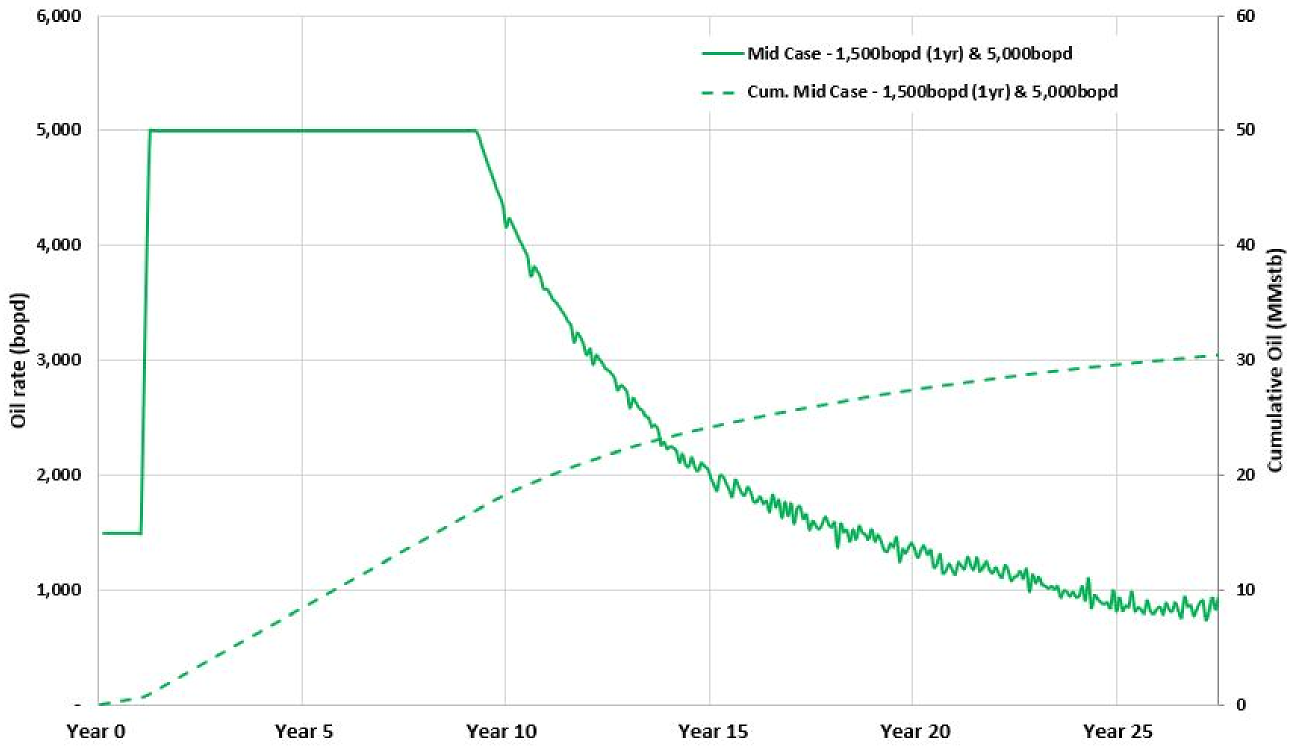

Figure 5-1 Base case Oil forecast for R3 East discoveries

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.

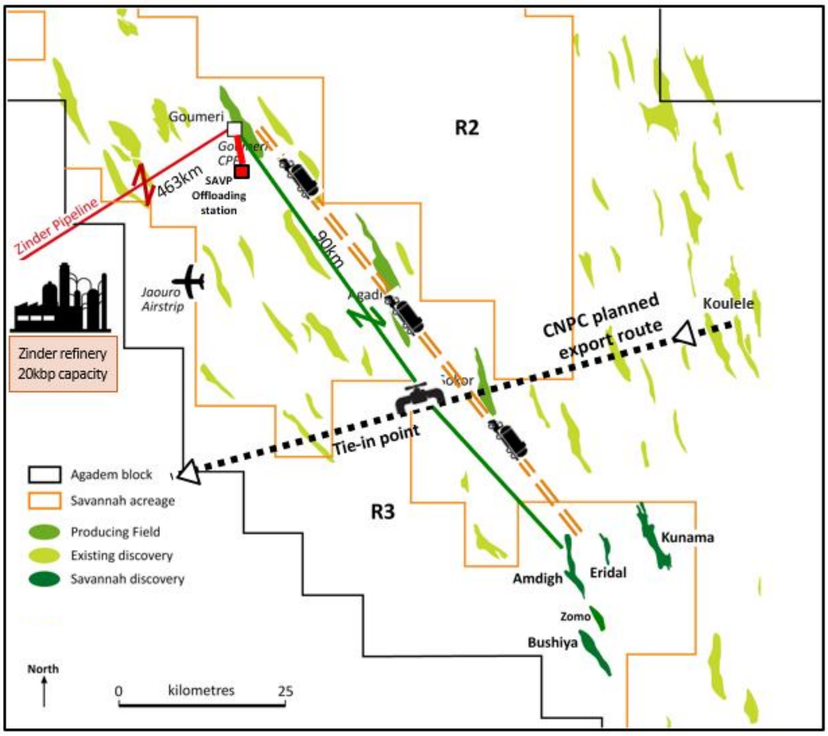

Figure 6-1 Proposed Early Production Scheme Development *(Source: Savannah, 2019)*

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**.

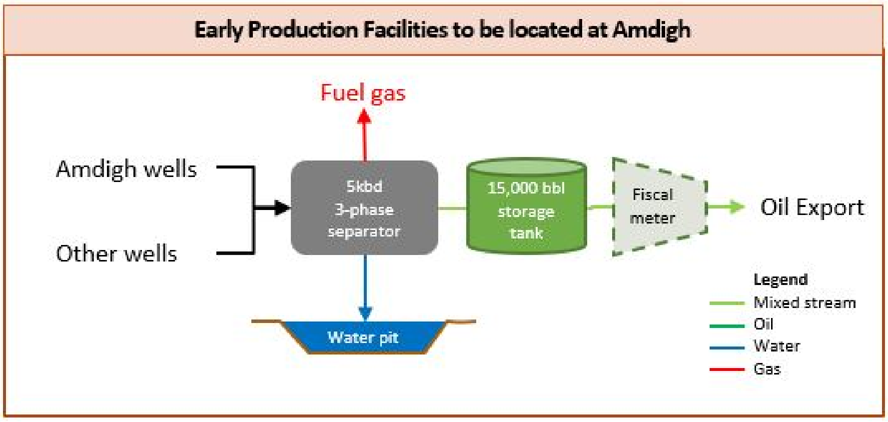

Figure 6-2 R3 East Early Production Facilities *(Source: Savannah, 2019)*

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.

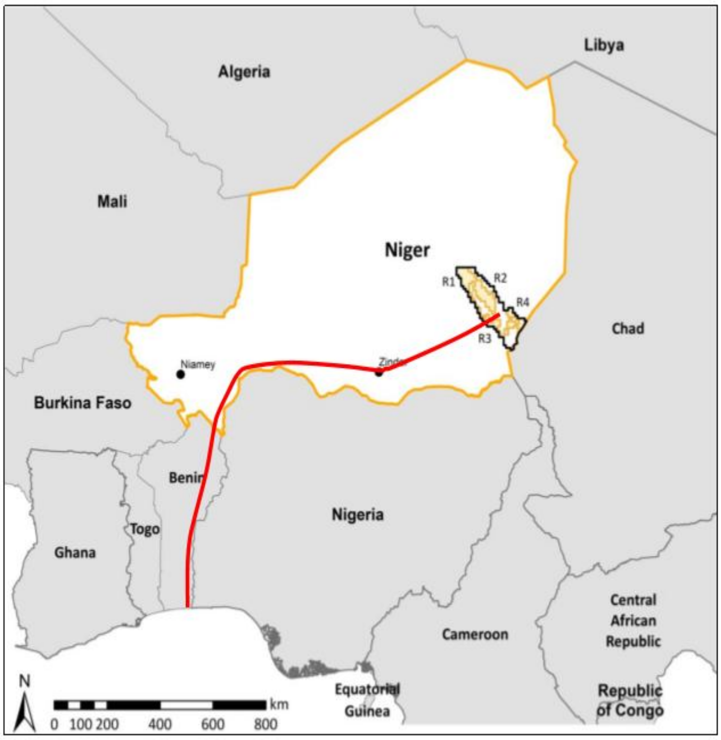

Figure 6-3 Proposed Route of Niger to Benin Export Pipeline

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.

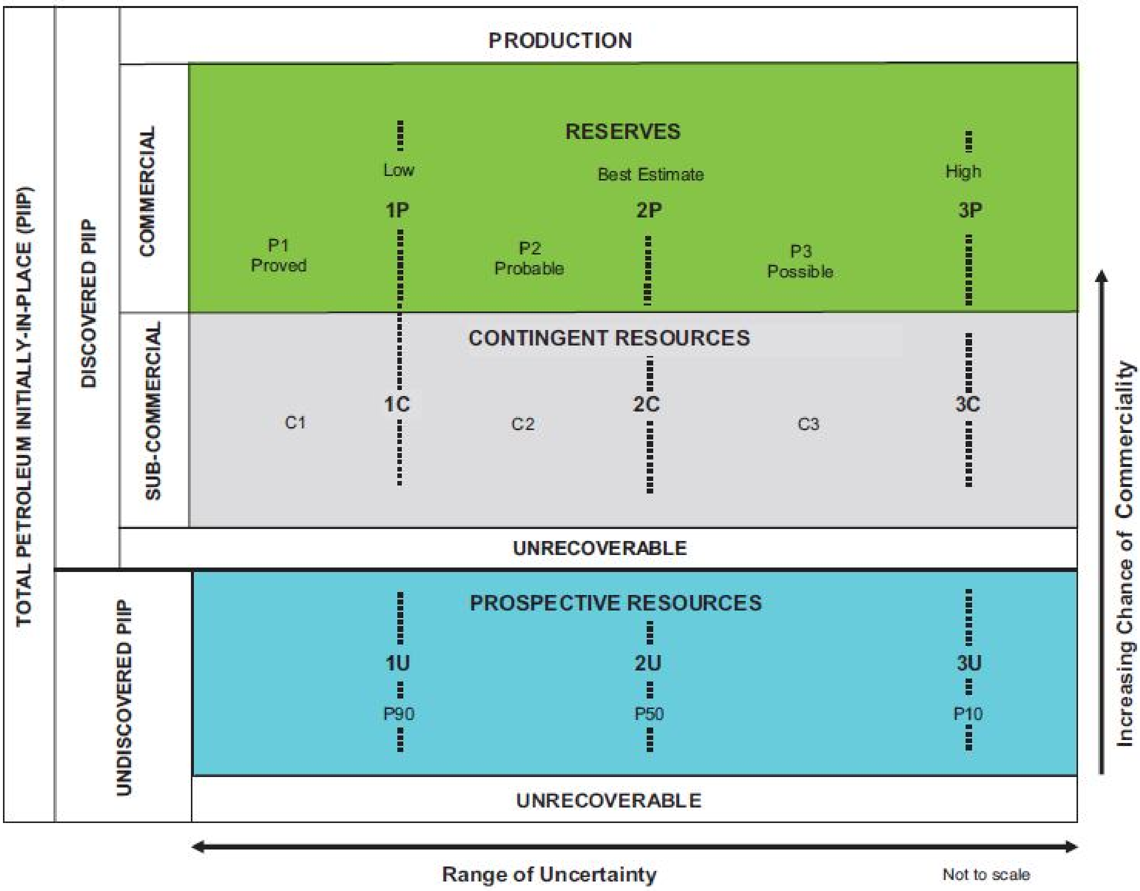

Figure 7-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System, 2018)

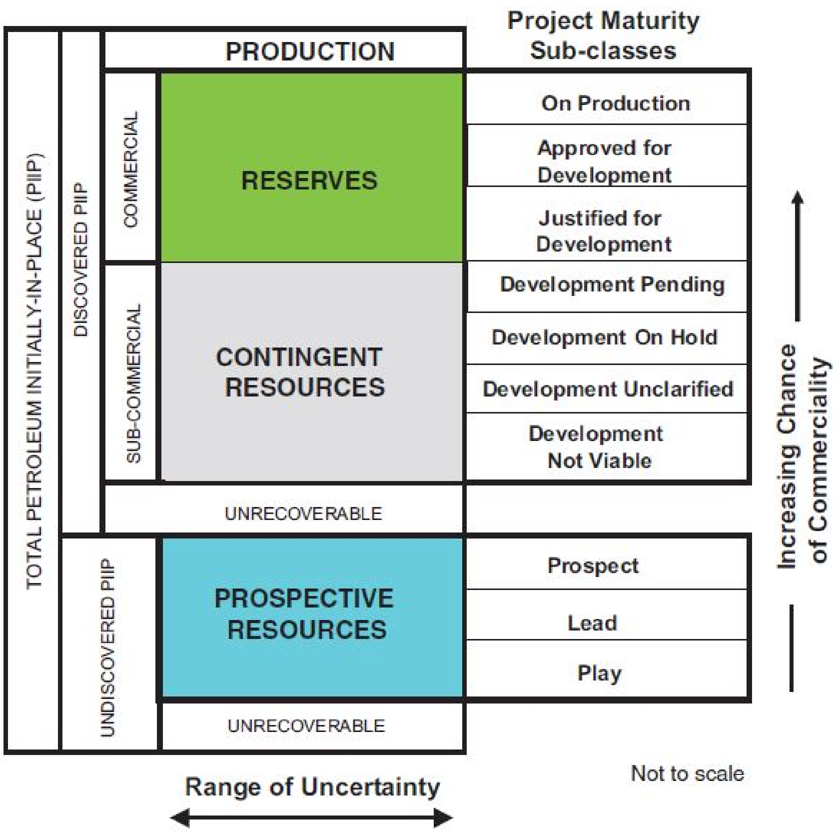

Figure 7-2 Resources Classification Framework: Sub-classes based on Project Maturity

(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
mbsl	metres below sea level
MBOPD	thousand bbls of oil per day
MCFD	thousand cubic feet per day
MCFGD	thousand cubic feet of gas per day
mD	millidarcies
MD	measured depth
mdst.	mudstone
MFS	maximum flooding surface
mg/gTOC	units for hydrogen index
mGal	milligals
MHz	megahertz
million m^3	million cubic metres
ml	millilitres
mls	miles
MMBO	million bbls of oil
MMBOE	million bbls of oil equivalent
MMBOPD	million bbls of oil per day
MMCFGD	million cubic feet of gas per day
MMTOE	million tons of oil equivalent
mmsl	metres below mean sea level
mN/m	interfacial tension measured unit
MPa	megapascals
mSS	metres subsea
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
N	north
NaCl	sodium chloride
NFW	new field wildcat
NGL	natural gas liquids
NPV	net present value
no.	number (not #)
NTG	Net toGross
OAE	oceanic anoxic event
OI	oxygen index
OWC	oil-water contact
P90	proved
P50	proved + probable
P10	proved + probable + possible
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
Ø	porosity
plc	public limited company
por.	porosity
poroperm	porosity-permeability
ppm	parts per million
psi	pounds per square inch
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, measured at 14.7 pounds per square inch and 60 degrees Fahrenheit
SCF/STB	standard cubic feet per stock tank barrel
SS	sub-sea
ST	sidetrack (well)
STB	stock tank barrels
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
TCF	trillion (10^{12}) cubic feet
TD	total depth
TDC	tangible drilling costs
Therm	105 Btu
TVD	true vertical depth
TVDSS	true vertical depth subsea
TVDmsl	true vertical depth below MSL
TWT	two-way time
US$	US dollar, the currency of the United States of America
UV	ultra-violet
VDR	virtual dataroom

W	West
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
WD	water depth
wt%	percent by weight
XRD	X-ray diffraction (analysis)