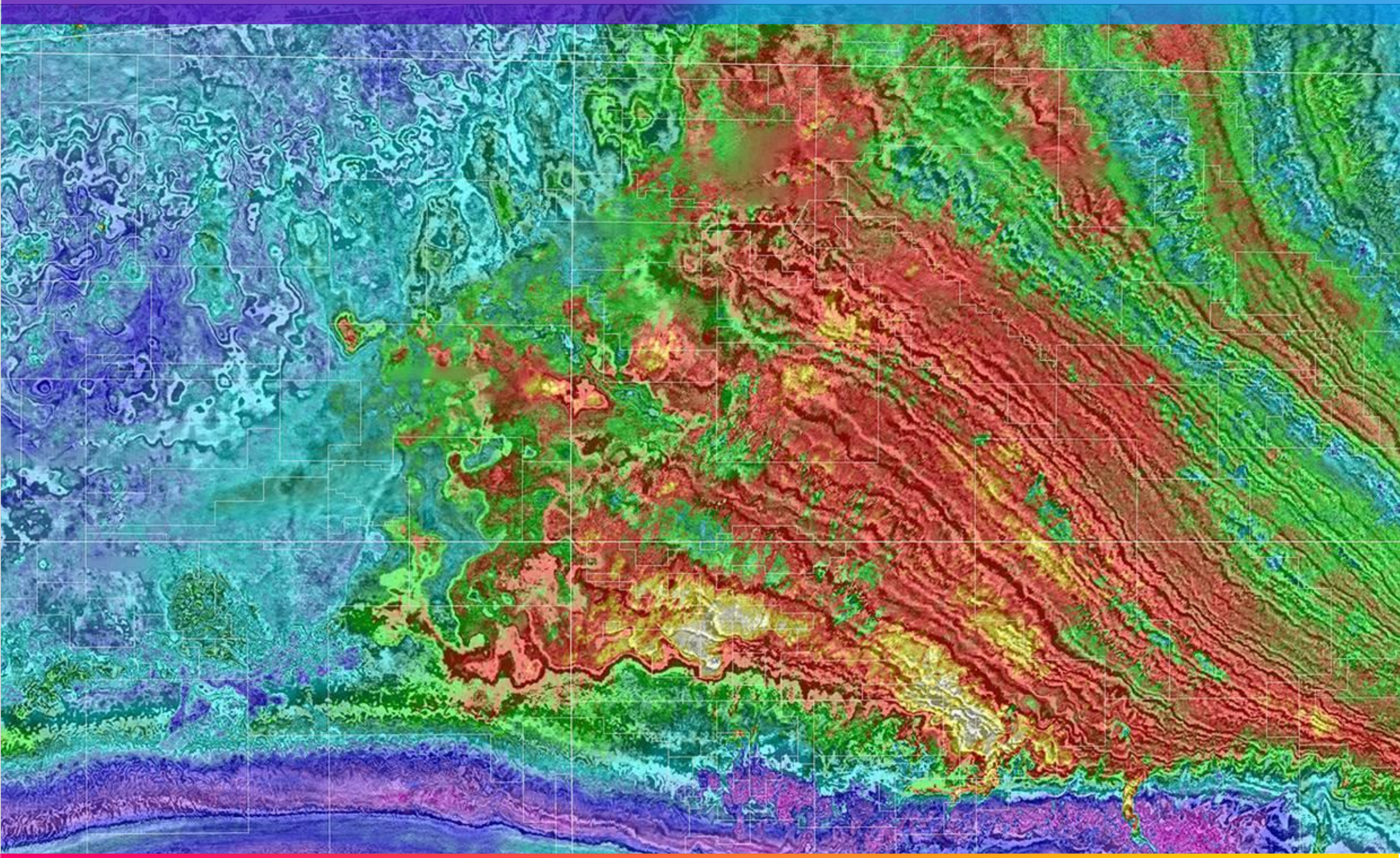

COMPETENT PERSONS REPORT

Uquo and Stubb Creek fields, Nigeria

For
Savannah Energy PLC
Strand Hanson Limited
Cavendish Capital Markets Ltd
Panmure Gordon (UK) Limited

DISCLAIMER AND CONDITIONS OF USAGE

Professional Qualifications

CGG Services (UK) Limited (CGG) is a geological and petroleum reservoir consultancy that provides a specialist service in field development and the assessment and valuation of upstream petroleum assets.

CGG has provided consultancy services to the oil and gas industry for over 50 years. The work for this report was carried out by CGG specialists having between five and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

Data and Valuation Basis

In estimating petroleum in place and recoverable, CGG has used the standard techniques of petroleum engineering. There is uncertainty inherent in the measurement and interpretation of basic geological and petroleum data. There is no guarantee that the ultimate volumes of petroleum in place or recovered from the field will fall within the ranges quoted in this report.

CGG has independently assessed the proposed development schemes and validated estimates of capital and operating costs, modifying these where it was judged appropriate. The capital and operating costs have been combined with production forecasts based on the Reserves or Resources at the P90 (Proved), P50 (Proved + Probable) and P10 (Proved + Probable + Possible) levels of confidence and the other economic assumptions outlined in this report in order to develop an economic assessment for these petroleum interests. CGG's valuations do not take into account any outstanding debt or accounting liabilities, nor future indirect corporate costs such as general and administrative costs.

CGG has valued the petroleum assets using the industry standard discounted cash flow technique. In estimating the future cash flows of the assets CGG has used extrapolated economic parameters based upon recent and current market trends. Estimates of these economic parameters, notably the future price of crude oil and natural gas, are uncertain and a range of values has been considered. There is no guarantee that the outturn economic parameters will be within the ranges considered.

In undertaking this valuation CGG have used data supplied by Savannah in the form of geoscience reports, seismic data, engineering reports and economics data. The supplied data has been supplemented by public domain regional information where necessary.

CGG has used the working interest percentages that Savannah Energy PLC has in the Properties, as communicated by Savannah Energy PLC. CGG has not verified nor do they make any warranty to Savannah Energy PLC's interest in the Properties.

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CGG affirms that from 1st January 2024 (the effective date of the evaluation) to the date of issue of this report, 1) there are no material changes known to CGG that would require modifications to this report, and 2) CGG is not aware of any matter in relation to this report that it believes should and may not yet have been brought to the attention of Savannah Energy PLC.

In order to conform to the AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange, CGG has compiled this CPR to conform with Petroleum Resources Management System (PRMS) (2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE). Further details of PRMS are included in **Appendix B** of the CPR.

Conditions of Usage

This report was compiled using existing data during the period 1st September 2023 to 1st January 2024. However, if substantive new data or facts become available or known, then this report should be updated to incorporate all the relevant data.

CGG has made every reasonable effort to ensure that this report has been prepared in accordance with generally accepted industry practices and based upon the data and information supplied by Savannah Energy PLC for whom, and for whose exclusive and confidential use (save for where such use is for the Purpose defined below), this report is made. Any use made of the report shall be solely based on Savannah Energy PLC's own judgement and CGG shall not be liable or responsible for any consequential loss or damages arising out of the use of the report.

The copyright of this CPR document remains the property of CGG. It has been provided to Savannah Energy PLC, Strand Hanson Limited, Cavendish Capital Markets Ltd and Panmure Gordon (UK) Limited for the purpose of including it (and making any references to it or its contents) in Savannah Energy PLC's published public announcements relating to its Nigerian assets and disclosing it on the Savannah Energy PLC's website in accordance with the AIM Rules and specifically to the AIM Note for Mining, Oil & Gas Companies (these together being the "Purpose"). CGG agrees to disclose the enclosed CPR to Savannah Energy PLC, its affiliates, Strand Hanson Limited, Cavendish Capital Markets Ltd and Panmure Gordon (UK) Limited for the Purpose. Save for use in connection with the Purpose, the recipient should also note that this document is being provided on the express terms that, other than for the Purpose, it is not to be copied in part or as a whole, used or disclosed in any manner or by any means unless as authorised in writing by CGG. Notwithstanding these general conditions, CGG additionally agrees to the publication of the CPR document, in full, on the Savannah Energy PLC's website in accordance with the AIM rules.

The accuracy of this report, data, interpretations, opinions and conclusions contained within, represents the best judgement of CGG, subject to the limitations of the supplied data and time constraints of the project. In order to fully understand the nature of the information and conclusions contained within the report it is strongly recommended that it should be read in its entirety.

CGG Services (UK) Limited Reference No: NB540				
Rev	**Date**	**Originator**	**Checked & Approved**	**Issue Purpose**
01	18th March 2024	AKS/PC/PMD/TU	AJW	Final Report

Date	**Originator**	**Checked & Approved**
Signed:18th March 2024	***AKS/PC/PMD/TU***	

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1 EXECUTIVE SUMMARY

At the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, Cavendish Capital Markets Ltd and Panmure Gordon (UK) Limited, CGG Services (UK) Limited (CGG) have prepared a Competent Persons Report (CPR) on the petroleum interests held by Savannah Energy PLC (Savannah) in Nigeria, namely, the Uquo and Stubb Creek Marginal Fields and the Accugas Midstream Business (Accugas).

The effective date for the evaluation is 1st January 2024.

1.1 Licence interests

Savannah holds an 80% interest in the exploration, development and production of gas within the Uquo Field through its 80% indirectly owned subsidiary Savannah Energy Uquo Gas Limited (SEUGL). The remaining 20% indirect interest in SEUGL is held by African Infrastructure Investment Managers (AIIM), a leading African-focused private equity firm. SEUGL holds responsibility for all operations of the gas project at the Uquo Field, including control of gas-related capital investment projects and day to day gas operations.

Savannah also holds a direct 51% operated interest in the Stubb Creek Field through its 100% ownership of Universal Energy Resources Limited (Universal).

In addition, Savannah holds an 80% interest in Accugas, which owns and operates the 200 MMscf/d Uquo gas Central Processing Facility (CPF) and c. 260 km pipeline network, as well as holding Gas Sales Agreements (GSA) with downstream customers. The remaining 20% interest in Accugas is held by AIIM.

Asset	Operator	Savannah's Interest (%)	Status	Licence expiry date	Licence Area
Uquo Gas	SEUGL*	80%	Production	2035	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

** SEUGL is the Operator of the Uquo Gas Project*

Table 1-1 Current licence details

For the Uquo Marginal Field, the licence was renewed by the Nigerian Upstream Petroleum Regulatory Commission (NUPRC) for a period of 20 years on 18th June 2015. For the Stubb Creek Marginal Field, the licence was renewed by the NUPRC for a period of 10 years from 1st May 2016.

CGG have assumed, based on its experience, and pursuant to the relevant Marginal Field Guidelines, that the NUPRC is likely to extend the licences beyond the above tabulated expiry dates, if there are still Reserves to be produced. These extensions would be awarded in several phases until the fields reached the end of their economic lives. The Reserves stated in this CPR therefore assume production to the end of the economic lives of the fields.

1.2 Asset details

1.2.1 Uquo Field

The Uquo Field produces gas from 5 wells and has been on production since Q1 2014. Production is sold under a GSA to Accugas, a company in which Savannah has an 80% interest. Accugas currently processes, distributes and markets the gas to one power plant and a cement factory under long-term take or pay contracts, as well as other industrial customers in the Port-Harcourt area. A summary of the contracts is in **Table 1-2**. To maintain the contracted production rates, Savannah plans to bring onstream 3 additional wells over the next 6 years while Accugas will install compression facilities at the Uquo CPF. A water disposal well is also planned.

1.2.2 Stubb Creek Field

The Stubb Creek Field is producing oil from 3 wells and has been on production since Q1 2015. Production is transported via pipeline to the ExxonMobil operated Qua Iboe Terminal. Universal plans to debottleneck the production facility to increase capacity from about 3,000 bopd to 5,000 bopd. A water disposal well is also planned. The Contingent Gas Resources will be developed and sold to Accugas, once the Uquo Field Reserves and Contingent Resources are not sufficient to meet the Daily Contracted Quantity (DCQ).

1.2.3 Accugas

The Accugas facilities consist of a 200 MMscf/d gas Central Processing Facility (CPF) located near to the Uquo Field, and approximately 260 km of pipelines connecting the CPF to the current Downstream gas purchasers. Total Daily Contracted Quantity (DCQ) under two long-term GSA's is 155.2 MMscf/d, and these GSAs have Take or Pay (ToP) provisions within them (set at 80% of DCQ). Additional volumes are also contracted under Interruptible GSAs with Central Horizon Gas Company (CHGC), a subsidiary of Axxela, Notore Chemical Industries (Notore), Shell Petroleum Development Company of Nigeria (SPDC) and Shell Nigeria Gas Limited (SNG).

	Length of contract	Start date	Contract end	DCQ	Take or Pay (ToP)
Calabar Power Plant	20 years	Sep-17	Sep-37	131.0 MMscf/d	80% of DCQ
Lafarge Africa Plc (was Unicem Cement Plant)	25 years	Jan-12	Jan-37	24.19 MMscf/d	80% of DCQ
CHGC (an Axxela subsidiary)	1-year initial term extended by 12 months	Jun-22	Jun-24	Nominations up to 10 MMscf/d	N/A
Notore	1-year initial term extended by 12 months	Aug-22	Aug-24	Nominations up to 10 MMscf/d	N/A
The Shell Petroleum Development Company of Nigeria (SPDC)	6-month initial period extended	Jun-22	Apr-24	Nominations up to 3 MMscf/d	N/A
Shell Nigeria Gas Limited (SNG)	6-month initial period extended by 6 months	Jun-23	June-24	Nominations up to 3 MMscf/d	N/A

Table 1-2 Details of Accugas GSA's

1.3 Reserves and Resources

A summary of the Reserves and Resources associated with the Uquo and Stubb Creek fields, both gross and net attributable to Savannah, in accordance with the 2018 Petroleum Resource Management System (PRMS), are shown in the tables below. Net attributable Reserves have been derived from Savannah's economic model. Net attributable Contingent and Prospective Resources have been estimated by multiplying gross Resources by the respective ratio derived from the economic model.

Reserves							
	Gross on Licence			Net attributable			Operator
	Proved	Proved & Probable	Proved, Probable & Possible	Proved	Proved & Probable	Proved, Probable & Possible	
Oil (MMstb)							
Stubb Creek	4.5	11.9	21.6	1.4	3.8	7.1	Universal
Gas (Bscf)							
Uquo	289.2	456.2	549.3	231.4	364.9	439.4	SEUGL
Condensate (MMstb)							
Uquo	0.4	0.6	0.8	0.3	0.5	0.6	SEUGL

Notes
1. *Reserves must be discovered, recoverable, commercial, and remaining based on the development project(s) applied*
2. *Volumes are sub-divided into Proved, Proved and Probable, and Proved, Probable and Possible to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *Reserves are stated after the application of an economic cut-off*
4. *Net: the portion of the gross reserves attributable to Savannah before royalties, taxes and fuel consumed in operations*
5. *Full definitions of the Reserves categories can be found in Appendix B*

Table 1-3 Reserves as at 1st January 2024

Contingent Resources								
	Gross on Licence			Net attributable			Risk Factor	Operator
	1C	2C	3C	1C	2C	3C		
Oil (MMstb)								
Stubb Creek	-	-	-	-	-	-		Universal
Gas (Bscf)								
Uquo	66.6	82.8	101.1	53.3	66.2	80.9	>75%	SEUGL
Stubb Creek	364.9	515.3	680.3	204.3	288.6	381.0	>75%	Universal

Notes

1. *Contingent Resources are those quantities of petroleum estimated to be potentially recoverable from known (discovered) accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies*
2. *Contingent Resources are stated before the application of a risk factor and an economic cut-off*
3. *1C, 2C and 3C categories account for the uncertainty in the estimates and denote low, best and high outcomes*
4. *The risk factor means the estimated chance that the volumes will be commercially extracted*
5. *Full definitions of the Contingent Resource categories can be found in Appendix B*
6. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 56% of gross volumes*

Table 1-4 Contingent Resources

Prospective Resources								
	Gross on Licence			Net attributable			Risk Factor	Operator
	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate		
Gas (Bscf)								
Uquo	325.6	513.1	842.2	260.5	410.5	673.7	25-75%	SEUGL
Stubb Creek	9.0	13.9	20.9	5.0	7.8	11.7	25-75%	Universal

Notes

1. *Prospective Resources are the volumes estimated to be potentially recoverable from undiscovered accumulations through future development projects*
2. *Volumes are sub-divided into low, best and high estimates to account for the range of uncertainty in the estimates, which correspond to the P90, P50 and P10 percentiles from a probabilistic analysis*
3. *The Prospective Resources are stated on an "unrisked" basis and before the application of an economic cut-off*
4. *The risk factor is defined as the chance or probability of discovering hydrocarbons in sufficient quantity for them to be tested to the surface, from any prospective stratigraphic level in the defined prospect*
5. *Risk factors: low = > 75%, medium = 25% - 75%, high = <25%*
6. *Full definitions of the Prospective Resource categories can be found in Appendix B*
7. *Net attributable volumes for Stubb Creek assume an entitlement to approximately 56% of gross volumes*

Table 1-5 Prospective Resources

1.4 Economic evaluation

The Net Present Values (NPV) of future cash flows derived from the exploitation of the Reserves as at 1st January 2024 are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes. The base Brent price assumption in the evaluation assumes real prices of US$80/bbl through 2024, and US$65/bbl in 2025 and beyond. From January 2024, the price is escalated at 2.5% per year. Gas prices are as stated in the respective GSA's.

NPV10 (US$MM) of Reserves Net to Savannah			
	Proved	Proved & Probable	Proved, Probable & Possible
Uquo (gas and condensate)	217.9	329.4	418.3
Stubb Creek oil	44.0	109.9	168.4
Total*	**261.8**	**439.4**	**586.7**

* Total may not add up due to rounding

Table 1-6 NPV10 (US$MM) of Reserves Net to Savannah as at 1st January 2024

Sensitivities have been calculated for total NPV for variations in oil price, Capex and Opex. The results of this analysis are tabulated below.

NPV10 (US$MM) Net to Savannah			
	Uquo	Stubb Creek	Total*
Base case (Proved+Probable)	329.4	109.9	439.4
Oil price - US$60/bbl	327.7	100.4	428.1
Oil price - US$70/bbl	330.1	115.4	445.5
Oil price - US$80/bbl	332.5	129.8	462.3
Oil price - US$90/bbl	334.9	143.8	478.7
Oil price - US$100/bbl	337.3	157.2	494.5
Capex +10%	326.6	109.4	435.9
Capex -10%	332.3	110.5	442.8
Opex +10%	327.8	108.5	436.3
Opex -10%	331.3	111.3	442.7

* Total may not add up due to rounding

Table 1-7 Proved and Probable NPV10 (US$MM) sensitivities as at 1st January 2024

The Net Present Values (NPV) of the future cash flows accruing to Accugas have been extracted from Savannah's integrated economic model and are tabulated below for the base case, Proved & Probable (2P) plus 2C. The model has been subject to a high-level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for Accugas (100%) and for Savannah's net 80% interest after deduction of Taxes. It should be noted that there are no gas Reserves or Resources associated with Accugas.

Case	Accugas (100%)	Net to Savannah
Base Case (2P+2C)	795.3	636.3

Table 1-8 Accugas NPV10s (US$MM) as at 1st January 2024

2 INTRODUCTION

2.1 Overview

This independent Competent Person's Report (CPR) was prepared by CGG at the request of Savannah Energy PLC (Savannah), Strand Hanson Limited, Cavendish Capital Markets Ltd and Panmure Gordon (UK) Limited. The report evaluates Reserves and Resources associated with the onshore Uquo and Stubb Creek Marginal Fields in which Savannah hold interests. These fields are located near the coast in south-east Nigeria.

Frontier Oil Limited (Frontier) and Universal Energy Resources Limited (Universal), both indigenous Nigerian E&P companies, are Operators of the Uquo and Stubb Creek fields, respectively.

Savannah Energy Uquo Gas Limited (SEUGL) has a 100% operating interest in the Uquo gas project (including associated condensate production). Savannah owns an 80% indirect interest in SEUGL, the remaining 20% is held by AIIM. Frontier has a 100% interest in the Uquo oil project.

Savannah has a 51% participating interest in the Stubb Creek Field. This interest is held via a 100% interest in Universal, which in turn holds a 51% interest in the field. The remaining 49% interest in the field is held by Sinopec International Petroleum Exploration and Production Company Nigeria Limited (SIPEC).

Savannah also owns an 80% operated interest in Accugas, the owner of the Uquo gas Central Processing Facility and associated pipeline network. The remaining 20% is held by AIIM. Accugas purchases Uquo gas production, which it then currently sells to one local power plant and a cement factory, as well as other industrial customers in the Port Harcourt area. A summary of Savannah's licence interests are tabulated below (**Table 2-1**).

Asset	Operator	Savannah's Interest (%)	Status	Licence expiry date	Licence Area
Uquo Gas	SEUGL*	80%	Production	2035	171 km^2
Stubb Creek	Universal	51%	Production	2026	42 km^2

** SEUGL is the Operator of the Uquo Gas Project*

Table 2-1 Current licence details

The location of the Uquo and Stubb Creek fields, and the Accugas surface facilities are shown in **Figure 2-1**.

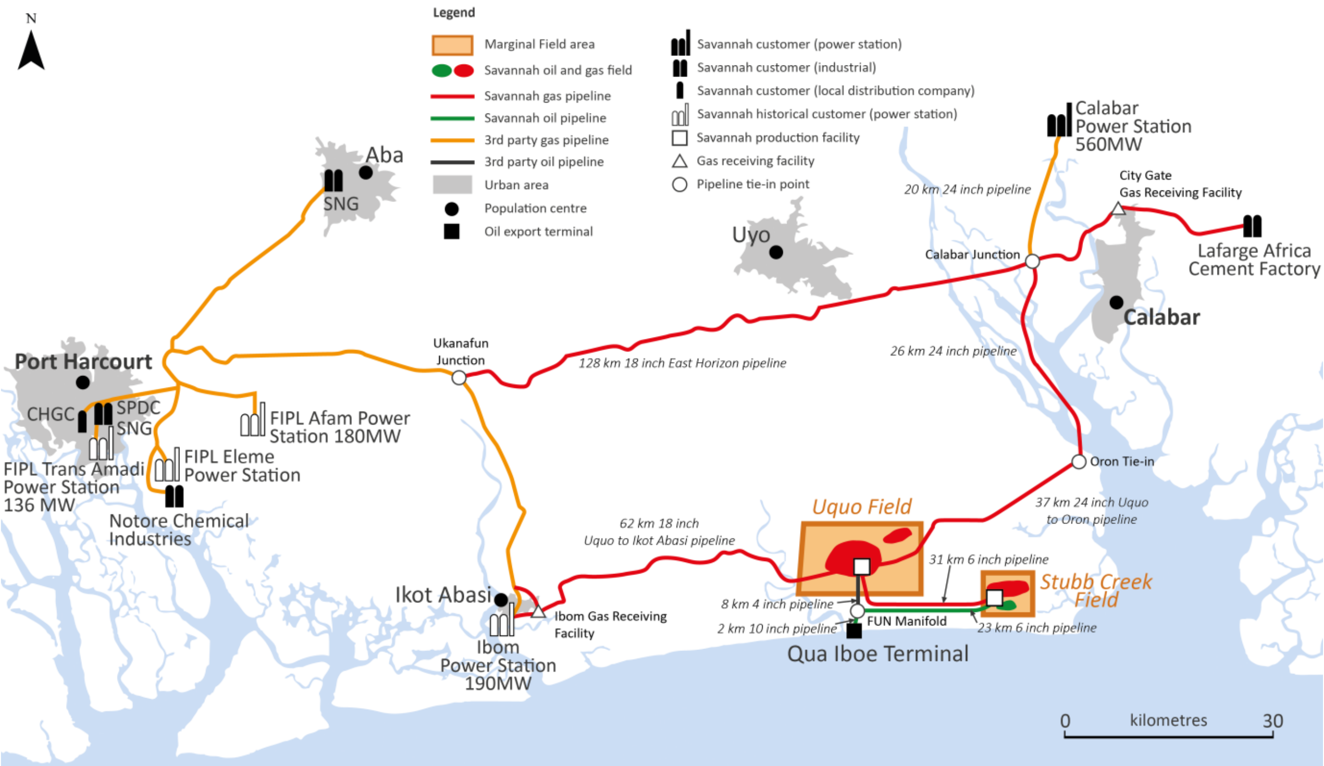


Figure 2-1 Location of fields and infrastructure *(Source: Savannah, 2023)*

2.2 Sources of information

In completing this evaluation, CGG has reviewed information and interpretations provided by Savannah's technical teams as well as utilising complementary information from the public domain.

Data utilised by CGG in the preparation of this CPR has included:

- Location maps
- Geological and reservoir reports
- Well logs of drilled wells
- Seismic workstation projects and associated interpretations, including 3D seismic over Uquo
- 3D geocellular model for Uquo Field
- Historical production and pressure data
- Gas sales contracts and farmout agreements
- Work plans and budgets

In conducting the evaluation, CGG have accepted the accuracy and completeness of information supplied by Savannah, and have not performed any new interpretations, simulations or studies.

No site visit to the facilities has been conducted by CGG as it was not part of the work scope in the letter of engagement.

2.3 Principal contributors

CGG employees and consultants involved technically in the drafting of this CPR have between 5 and 20 years of experience in the estimation, assessment and evaluation of hydrocarbon reserves.

Andrew Webb

Andrew Webb has supervised the preparation of this CPR. Andrew is the Asset Evaluation Manager 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.

Dr. Arthur Satterley

Arthur Satterley has a BSc 1st Class in Geology, University College of Wales and a PhD from the University of Birmingham on Upper Triassic reef limestones and a post-doctoral research experience on platform carbonate margins. He has 25 years' experience of petroleum geological evaluations and resource assessments for both oil and gas fields throughout the exploration and development life cycle. He has experience of carbonate and clastic reservoirs in most major petroleum provinces.

Pablo Cifuentes

Pablo Cifuentes has a BSc in Petroleum Engineering. He has 20 years of experience in the oil and gas industry. Pablo is a specialist in 3D reservoir static model and uncertainty analysis with relevant experience in Colombia, Mexico, Ecuador and Angola. He also has experience in geopressure prediction for the Gulf of Mexico and North Sea.

Pedro Martinez Duran

Pedro Martinez obtained a BSc in Geology at the University of Zaragoza (Spain) in 1993 studying the last two years in Burgundy University (France) and University of Aberdeen. Later he obtained an MPhil in carbonate sedimentology and sequence stratigraphy at the University of Zaragoza, publishing several papers related to these subjects. For some years he pursued a career as an exploration mining geologist (working in Chile, Argentina, Bolivia, USA, Turkey, Portugal, France and Italy) before becoming a petroleum geologist and completing an MSc in Petroleum Geoscience at Royal Holloway in 2011. Pedro as since joined CGG as Petroleum Geologist and Seismic Interpreter. Since then, he has been involved as seismic interpreter in almost all the main multi-client surveys acquired by CGG such as Australia, New Zealand, Banda Arc, Gabon, etc. Pedro is a member of the AAPG, EAGE and PESGB.

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 written several technical papers, published by GSTT and SPE.

Peter Wright

Peter Wright gained an MA in Engineering from Cambridge University and an MBA from Cranfield University. He has over 20 years' experience in the economic evaluation of upstream oil and gas assets including exploration prospects, development projects and producing assets. His career has included working as a director of specialist economics focussed consulting companies and has covered a variety of asset types both onshore and offshore in Europe and the rest of the world. He also regularly delivers training courses on petroleum economics and risk analysis at various centres around the world. He is a member of the Society of Petroleum Engineers.

2.4 Evaluation methodology

In evaluating the Reserves and Resources associated with the fields, CGG has used the accepted standard industry techniques of geological, engineering and economic estimation. More detailed descriptions of the workflow and methodologies employed are provided in the relevant sections of this report.

As an initial stage in the evaluation process, the seismic interpretation was reviewed during a visit by CGG to Savannah's London office in October 2018. During the same visit, geological, engineering and commercial issues were also discussed face to face with technical staff. In June 2021, Savannah provided new seismic interpretation and a 3D geocellular model for the Uquo Field and provided a review and official report on the updated gas-initially-in-place for the Uquo Field.

CGG has independently validated reservoir properties, Hydrocarbon Initially in Place, Reserves, production profiles and estimates of capital and operating costs provided by Savannah. The Reserves have been valued using Savannah's economic model based on predicted market trends. Estimates of these economic parameters are uncertain, and sensitivities derived from the base case have been considered.

CGG has relied on the validity, accuracy and completeness of the raw data provided by Savannah, and has not verified that data in any way, nor conducted any independent investigations or surveys. It should be noted that there is significant uncertainty inherent in the interpretation of geological and engineering data relating to hydrocarbon accumulations. These interpretations are subject to change over time as more data becomes available, and there is no guarantee that the ultimate hydrocarbon volumes recovered will fall within the ranges quoted.

The evaluation has been performed in accordance with the:

- Petroleum Resources Management System (PRMS, 2018) and the PRMS Guidelines (2011) sponsored by the Society of Petroleum Engineers (SPE), The American Association of Petroleum Geologists (AAPG), The World Petroleum Congress (WPC) and the Society of Petroleum Evaluation Engineers (SPEE)
- AIM Note for Mining, Oil & Gas Companies (June 2009) published by the London Stock Exchange

Except for the provision of professional services provided on a fee basis and products on a licence basis, CGG has no commercial arrangement or interest with Savannah Energy PLC (Savannah) or the assets, which are the subject of the report or any other person or company involved in the interests.

3 GEOLOGY AND GEOPHYSICS

3.1 Regional geology

The Uquo Field is located within the eastern Niger Delta, which is part of the prolific Niger Delta hydrocarbon province in Southern Nigeria. The Niger Delta is one of the world's largest Tertiary delta systems, covering an area of approximately 75,000 km^2, which has historically been fed by the Niger, Benue and Cross river systems. The basin is located on the West African continental margin at the site of a triple junction that formed during continental break-up during the Cretaceous. The delta sequence consists of an upward-coarsening regressive sequence of Tertiary clastic sediments up to 12 km thick. The dominant subsurface structures are listric normal faults (flattening downward), which detach close to the top of the underlying marine claystone surface at the top of the Akata Shale. These listric faults provide an array of trapping mechanisms for hydrocarbons in the subsurface, particularly within the associated rollover anticline structures. Major growth faults cross the delta from northwest to southeast, dividing the delta into a series of depobelts that have been prograding south-westwards for approximately 55 Myr (**Figure 3-1**).

The northern boundary fault for each of the depobelts marks the approximate position of the palaeo-coastline during the major progradational stages. Hydrocarbons have been located in all of the depobelts of the Niger Delta, typically in good quality sandstone reservoirs within the main deltaic sequence.

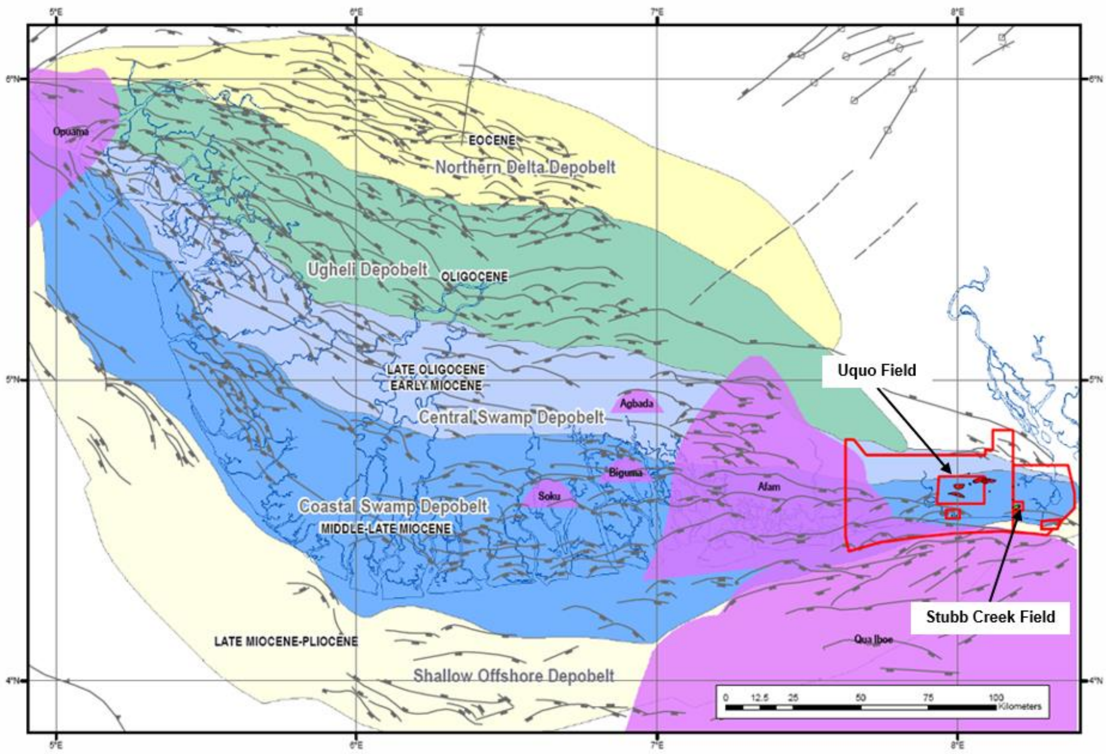


Figure 3-1 Depobelts of the Niger Delta *(Source: CGG)*

The stratigraphic sequence in the Niger Delta is broadly subdivided into the marine Akata Formation, paralic Agbada Formation and continental Benin Formation (**Figure 3-2**).

Hydrocarbons in the Uquo and Stubb Creek fields were generated from the prodelta mudstones of the Akata Formation and the interbedded paralic mudstones of the Agbada Formation. Upon maturation, hydrocarbons migrated either updip through carrier beds, or vertically along fault planes into the deltaic sandstones of the Early Miocene Agbada Formation. At Uquo and

Stubb Creek, the Agbada Formation is represented by the hydrocarbon-bearing “C” and “D” sands. The seal to these sands is provided by interbedded deltaic mudstones, which are thick and competent across the basin.

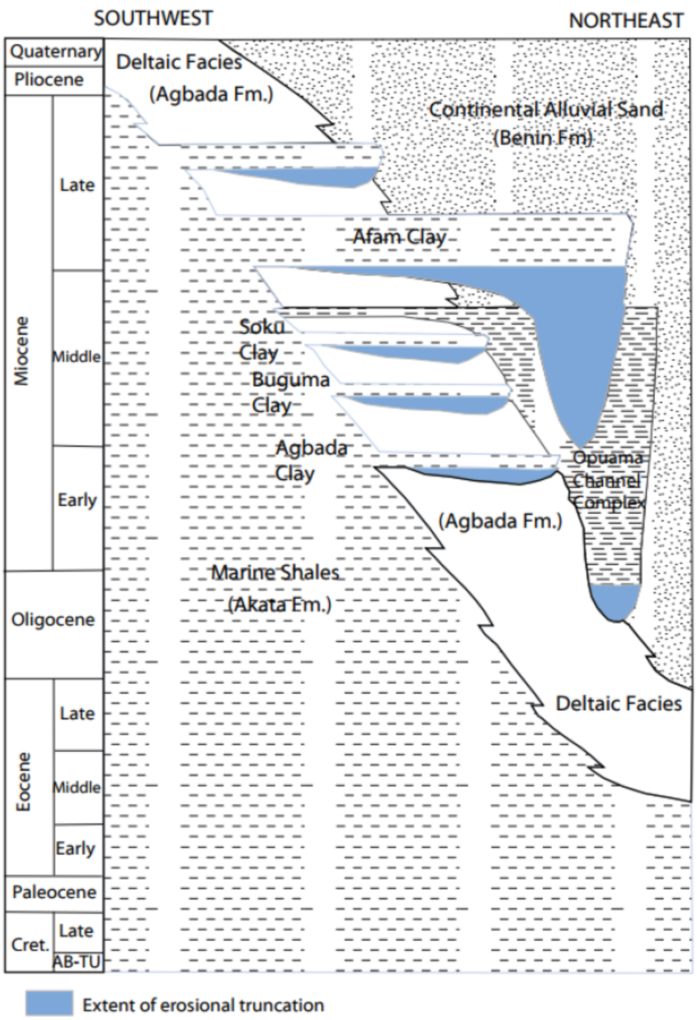


Figure 3-2 Lithostratigraphic column showing the key Tertiary sedimentary sequences in the Niger Delta *(Source: Tuttle et al., U.S. Geological Survey, 1999)*

3.2 Uquo Field

3.2.1 Uquo Field summary

The Uquo Marginal Field Licence is located within OML 13, onshore Nigeria. Gas has been discovered in 13 different ‘C’ and ‘D’ sand reservoirs in the Agbada Formation.

The Uquo Field is made up of 3 main areas; Uquo-2 (Uquo-2, 4 & 11 wells), Uquo-3 (Uquo-3, 7 & 8/8ST wells) and Uquo NE (Uquo 9/9ST well), with small volumes also present in Uquo-5 area (Uquo-1, 5, 5ST/6 & 10 wells). The upper ‘D’ reservoirs contribute the greatest volume of gas in the Uquo area (**Figure 3-3** and **Figure 3-4**).

The Uquo Field was first drilled in 1958 by Shell Petroleum Development Company Nigeria (SPDC); the composite logs from Uquo-1 supplied by Savannah suggest that this well only encountered thin gas intervals, although it was reported to have discovered oil and gas in four sands. The subsequent Uquo-2 well was drilled as an exploration well and encountered significant volumes of gas in all sand units between C9.0 and D5.0 (seven different reservoir intervals). Another exploration well and one appraisal well were drilled in 1971/72; Uquo-3 encountered gas in the D1.0 & D1.3/D1.4 sands, and oil in the D5.0 sand, whereas Uquo-4 encountered gas throughout the D1.0 sand and in the upper part of the D2.0 sand.

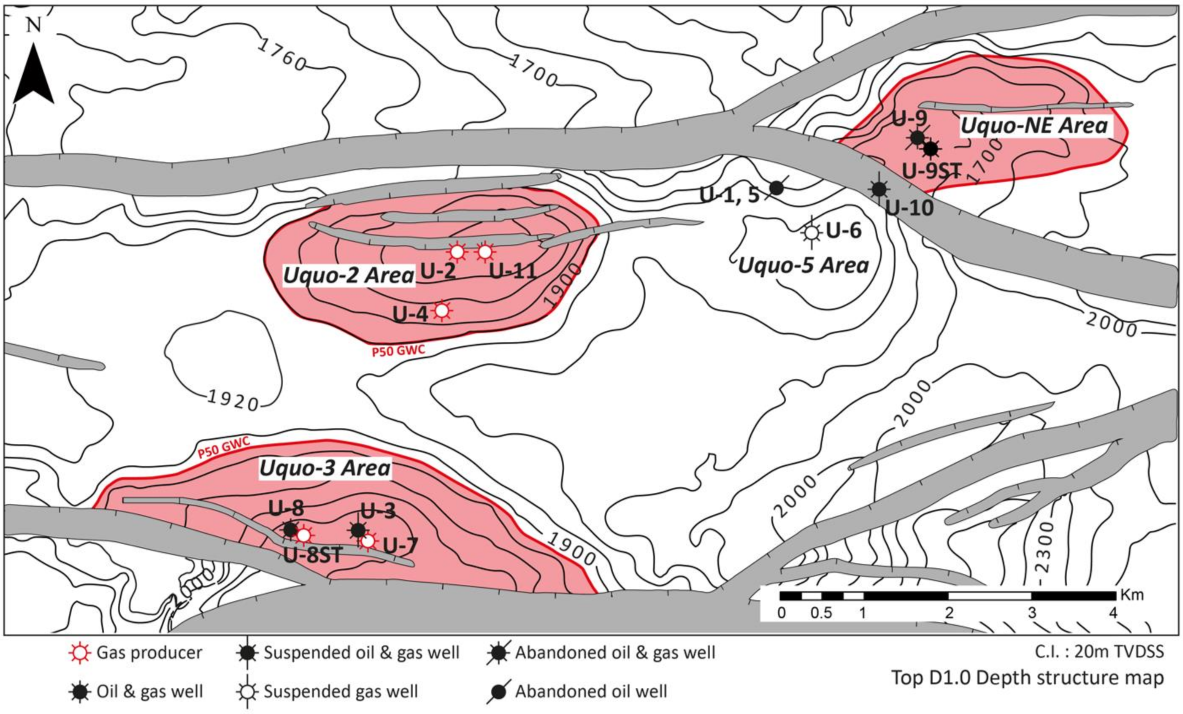


Figure 3-3 Uquo field structure map *(Source: Savannah, 2021)*

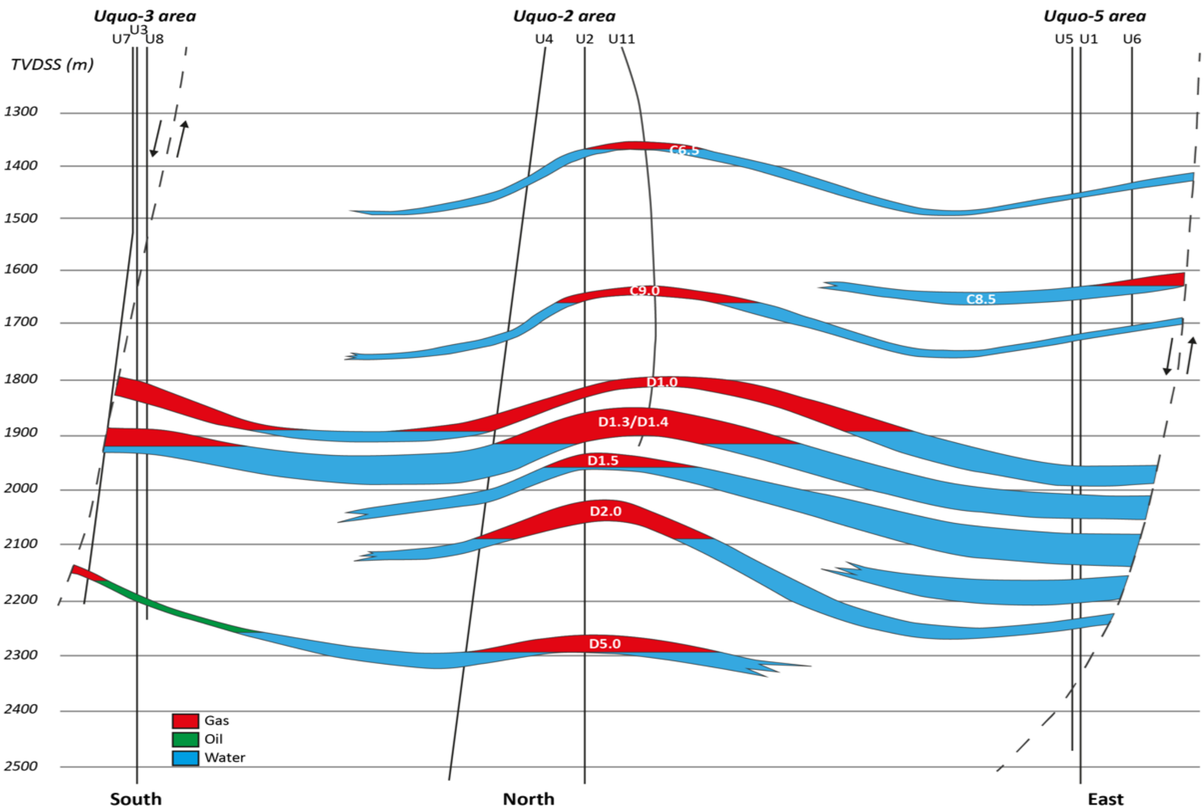


Figure 3-4 Schematic diagram showing the reservoir intervals of the Uquo field *(Source: Savannah, 2021)*

Drilling activity restarted in 2008, targeting oil discovered by Uquo-1; the Uquo-5 well failed to confirm the presence of the Uquo-1 oil accumulation. The well was then sidetracked (Uquo-5ST, aka Uquo-6), but was terminated before reaching the target depth due to mechanical problems. However, Uquo-5ST confirmed gas in one reservoir (C8.5). In January 2010, Uquo-3 was worked-over and completed as an oil producer in D5.0 reservoir, Uquo-2 and Uquo-4 were subsequently completed as gas producers in the D2.0 and D1.0 reservoirs, respectively. The gas accumulations were appraised by Uquo-7, -8 and -8ST between June and September 2013. Uquo-7 and -8ST were completed in 2014 as gas producers in D1.0 reservoir. Exploration drilling returned to the Uquo area in November 2014, resulting in the Uquo NE discovery with Uquo-9/9ST suspended as an oil and gas discovery. Uquo-9/9ST well was later completed in D1.6 reservoir – Uquo NE area and is operated as an oil producer by Frontier.

In 2021, Savannah drilled a gas development well, Uquo-11, in the Uquo-2 area. The well has been completed in the D1.0 and D1.3/D1.4 reservoirs. Uquo-11 proved that some 39 feet of the C9.0 reservoir section in nearby well Uquo-2 had been faulted out. Remapping of the Uquo-2 area reservoirs followed, incorporating the correct (greater) thickness of net sand in the area. Log evaluation conducted by Savannah shows that the total net pay thickness for the C9.0, D1.0 and D1.3/D1.4 reservoirs came 71 ft above prognosis with a total of 355 ft net pay thickness.

3.2.2 Uquo Field subsurface overview

CGG have carried out an independent analysis of the Uquo Marginal Field Licence using a PSDM (Pre-Stack Depth Migration) 3D seismic volume of 198 km^2 supplied by Savannah. This supersedes the 2019 evaluation from CGG which was based on the original Pre-Stack Time Migration (PSTM) seismic data. The PSDM seismic data was reprocessed by WesternGeco Seismic Nigeria Ltd. in 2020, starting from field tapes. A new velocity model has been prepared and the seismic interpretation and volumetrics have been revised.

The seismic survey was acquired between December 2006 and April 2007. Around 24.5 km^2 of the licence is not covered by seismic, due to the presence of the Eket Airfield to the west of the licence. In addition, there are areas within the dataset that suffer from poor fold coverage due to the presence of some villages.

Data was provided by Savannah to CGG as a Kingdom™ Project containing wells, horizons, faults and depth maps. The data and interpretations have been QC'd and used as a basis for volumetrics. Composite logs were supplied which contain formation depths as well as fluid contacts, and these have been used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The quality of the seismic data is generally good at the key reservoir levels, although the noted acquisition issues result in a decrease in data quality in a few areas. The footwalls of most of the faults are generally poorly imaged, particularly in the deeper section, which makes the delineation of some of the gas-bearing reservoirs more uncertain. In addition to the Kingdom™ project, Savannah provided reports concerning Petrophysics, Geoscience and Reservoir Engineering studies.

The Uquo Marginal Field Licence area contains several different structural features resulting from a set of listric faults trending in an overall E-W direction with a clear southern tectonic vergence. Listric growth fans were formed as a result of the rotation of both hangingwall and footwall as sedimentation took place.

Roll-over anticline structures are readily seen in the seismic data. A good understanding of the structural framework is vital as the structural highs generated by these features shape the pools in the Uquo area. There are three structural culminations in the main fault block, two in the north (Uquo-2 and 5 areas) which are dip-bounded, and one dip and fault-closed structure in the south (Uquo-3 area). At D1.0 level, Uquo-2 and Uquo-3 areas are in communication (pressure connection proven by production data) as seen in **Figure 3-5**. In the Uquo-2 area, the reservoirs are intersected by planar antithetic faults genetically related to the rotational movement of the main listric fault F2.

The Uquo-3 area has a different structural configuration, in that the reservoirs are trapped in the footwall of the large listric fault labelled as F3. The rotation of the main fault block has resulted in some structural relief into which hydrocarbons have migrated and remained trapped. The southern edges of the Uquo-3 area reservoirs are difficult to pick with accuracy in the deeper section, due to fault shadow effects in the seismic clearly seen in the left hand-side of **Figure 3-5**. Most of the gas reservoirs in the Uquo Field are easy to pick; many exhibit a bright amplitude response (**Figure 3-6**) as a result of the presence of gas within a high-quality, porous reservoir. Many also exhibit flat spots, which help to define the contacts in some of the accumulations (if no gas-water contact has been encountered in the wells on-structure).

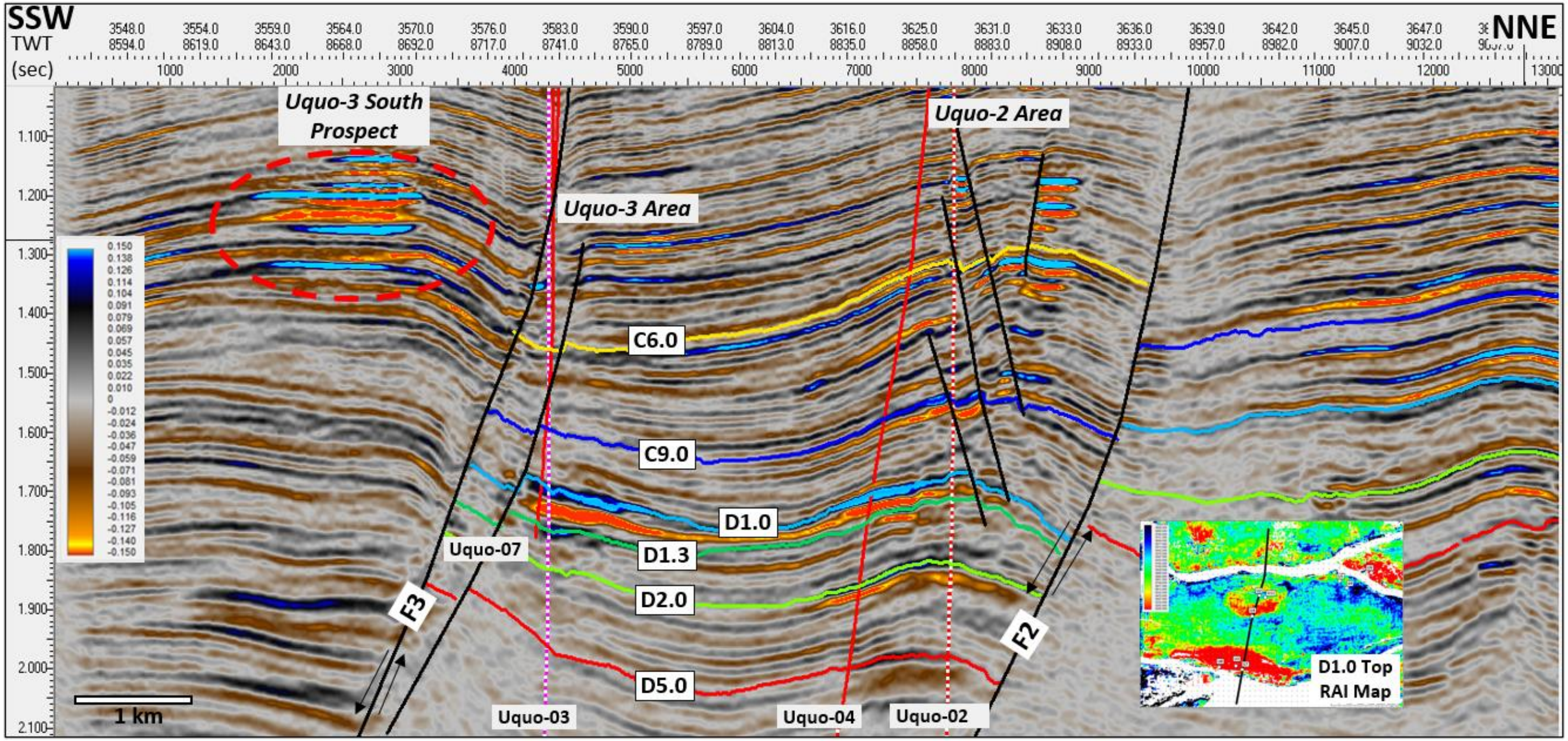


Figure 3-5 SSW-NNE seismic line through Uquo-3 and Uquo-2 areas *(Source: Savannah, 2021)*

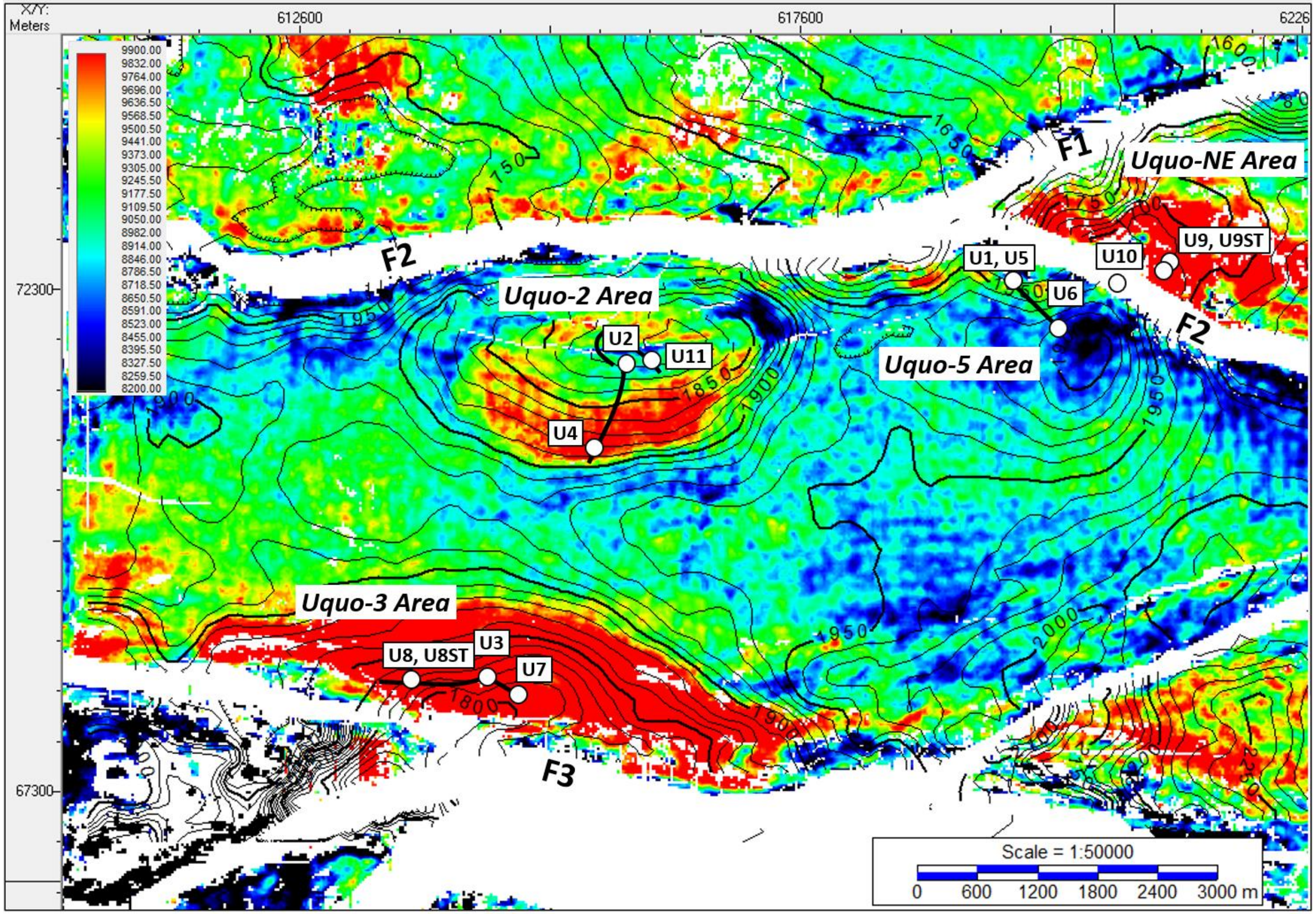


Figure 3-6 Relative Acoustic Impedance at the D1.0 level with depth contours in mSS *(Source: Savannah, 2021)*

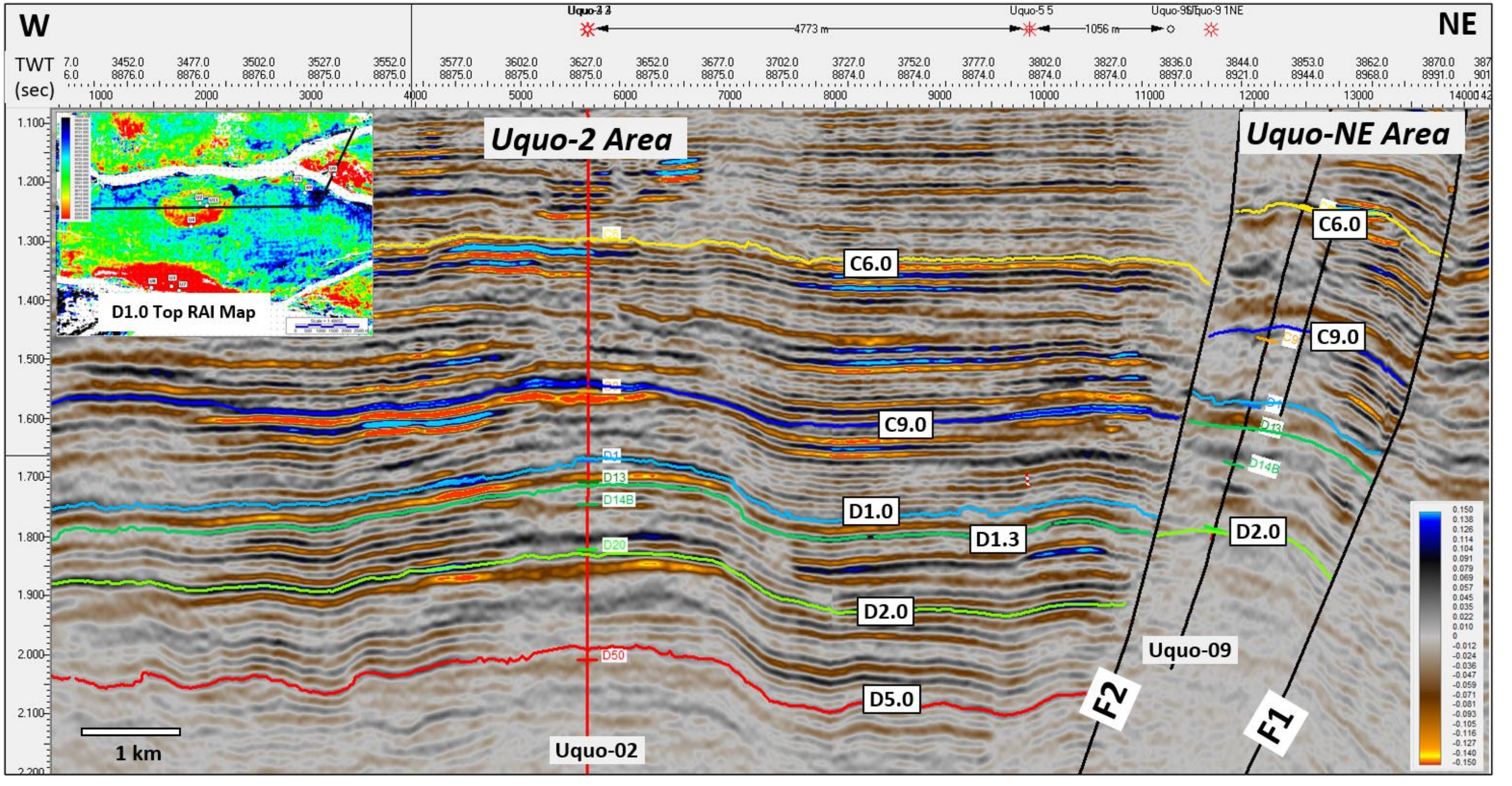


Figure 3-7 W-E Seismic crossline for Uquo-2 and Uquo NE area showing tops of target units. See inset map for location *(Source: Savannah, 2021)*

The Uquo-9/9ST discovery is located in a separate fault compartment (**Figure 3-7** and **Figure 3-8**), namely Uquo NE towards the North East of the main fault block. Hydrocarbons were discovered in 9 reservoirs in Uquo-9/9ST well; mainly gas except for the D1.6 and D7.0 reservoirs which encountered oil. The ultimate areal extent of the Uquo NE shallow gas discovery is unknown, as it extends outside the area of 3D seismic coverage (**Figure 3-6**). The seismic over Uquo NE area is quite poor (**Figure 3-7** and **Figure 3-8**) in places due to an overlying village, although this is mitigated by the data provided by the exploration well on the structure (Uquo 9/9ST).

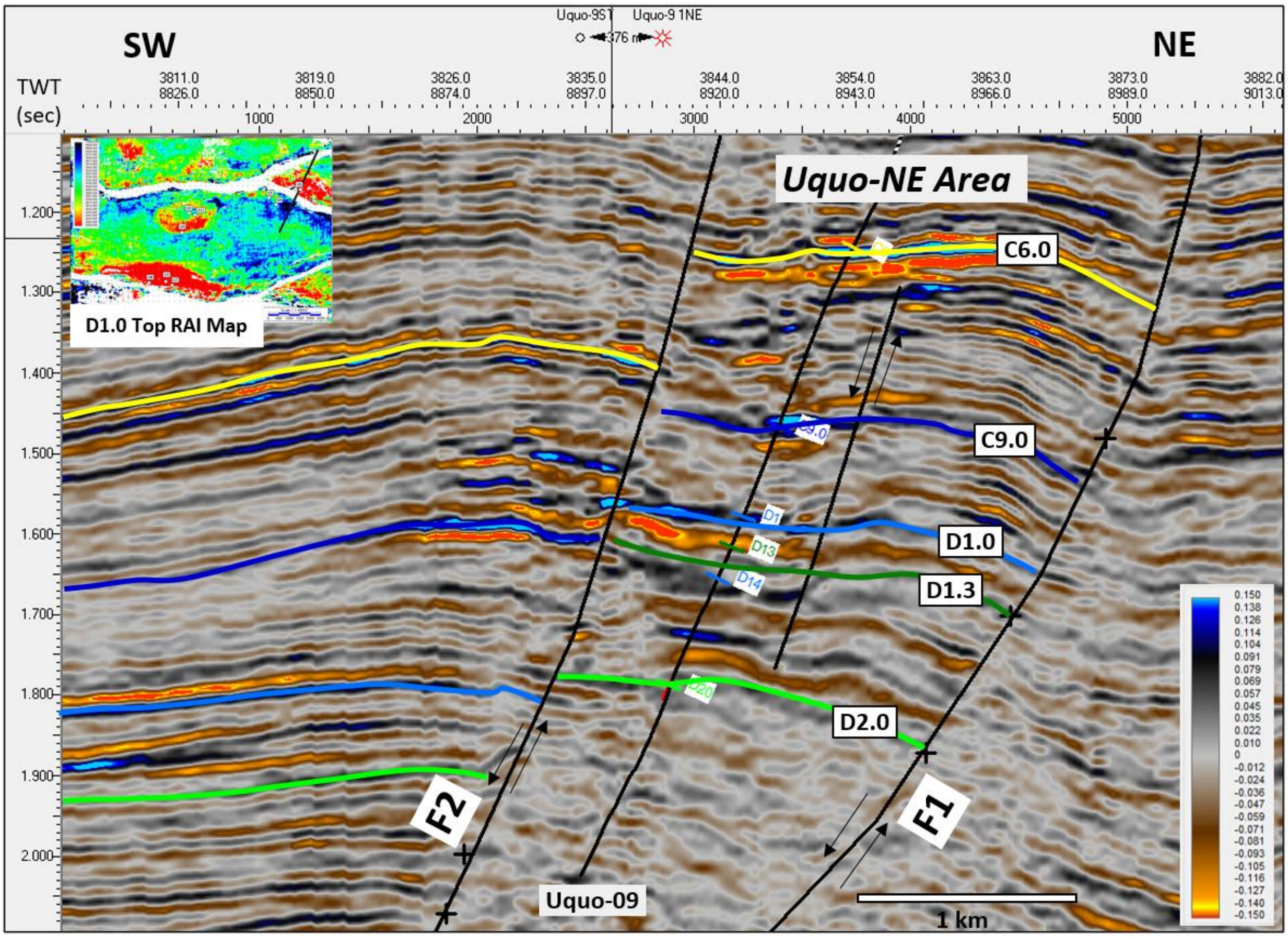


Figure 3-8 SW-NE seismic inline over Uquo NE area *(Source: Savannah, 2021)*

The Agbada C and D sand reservoirs are of high quality at the Uquo Field; NTG (Net-To-Gross) is generally in excess of 90% and porosity is typically 27% or higher. In addition to the discovered volumes, Savannah has identified a series of additional prospects (**Figure 3-9**).

The subsurface team at CGG has completed a thorough geophysical and geological QC of the work supplied by Savannah. For the seismic mapping QC, the Kingdom™ project provided has been used. CGG has independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by reservoir engineering and petrophysics experts who have also provided inputs for the volumetric calculations, which were run through a probabilistic Monte Carlo analysis.

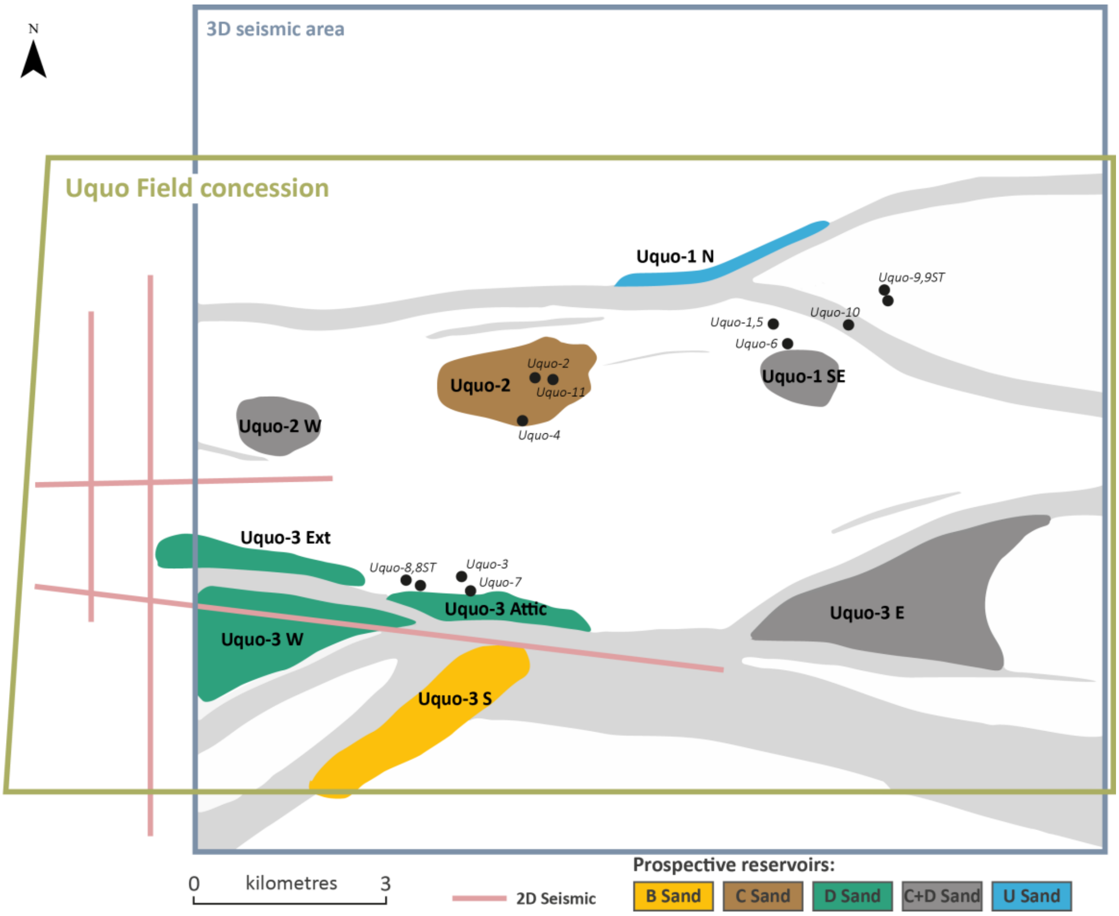


Figure 3-9 Map of prospects in the Uquo Marginal Field licence area *(Source: Savannah, 2024)*

In summary, the seismic interpretation of the top and base of the targeted units do not show major issues apart from minor irregularities and misties compared to well tops which is relatively commonplace. Depth maps from the static model were imported back into the Kingdom^{TM} seismic project for QC purposes and no major issues or changes were observed in terms of volumetrics. Given that the seismic reflections are very clear, the resulting depth maps were imported into the geomodel and depth shifted to match well tops without any changes in overall shape, CGG considers that the Gross Rock Volumes (GRV) arising from these maps is reliable.

There is uncertainty in the generation of the velocity model for conversion from time to depth domains. However, CGG considers this has been accounted for using a range of GRV values for P90, P50 and P10 estimates.

3.2.3 Uquo Field petrophysics

The petrophysical data provided for the C and D sands in the Uquo Field and the nearby Etebi well (Savannah, 2019) has been evaluated by CGG in order to obtain P10, P50 and P90 values for the reservoir properties such as the NTG, porosity and hydrocarbon saturations, which were used as inputs for the volumetric calculations. The methodology adopted for petrophysical analysis was found to be reasonable. This comprises the following computations: Volume of clay (Vcl) from GR logs using the Larionov model; and porosity from density log and water saturation using the Simandoux saturation model. An appropriate gas density correction was applied while estimating porosity from the density log, ensuring that calculated porosities are not overestimated. However, there is no density or sonic log available in Uquo-1 and Uquo-6 so effective porosity was estimated using a Vcl-porosity relationship derived from the nearby Uquo-5 well. Only sonic log was available down to the top of the D sands in the Uquo-8 well, thus porosity calculations are based on the sonic logs for the C sands and a Vcl-porosity relationship was applied to the deeper reservoirs. In the well intervals in which the Vcl relationship was used in determining the porosity (Uquo-1, Uquo-6 and deeper section of Uquo-8), the water saturation (Sw) estimates are based on the Archie equation.

The two sets of cut-offs used in deriving the net reservoir/pay are considered to be reasonable;

- Clean sands: porosity (0.16) and Vcl (0.45)
- Shaly sand: porosity (0.10) and Vcl (0.5)
- A uniform Sw cut-off of 0.50 has been applied throughout

Fluid contacts have also been determined from the petrophysical data and these have been used in combination with the Direct Hydrocarbon Indicators (DHI's) and structural closures in determining the Minimum, Most Likely and Maximum GRV's. **Figure 3-10** presents results from the Uquo-2 well which are representative of the rock properties of the Uquo Field.

During CGG's estimation of gas-initially-in-place, an appropriate range for average properties has been estimated with reference to the wells that penetrate the reservoir. This was done in each accumulation separately.

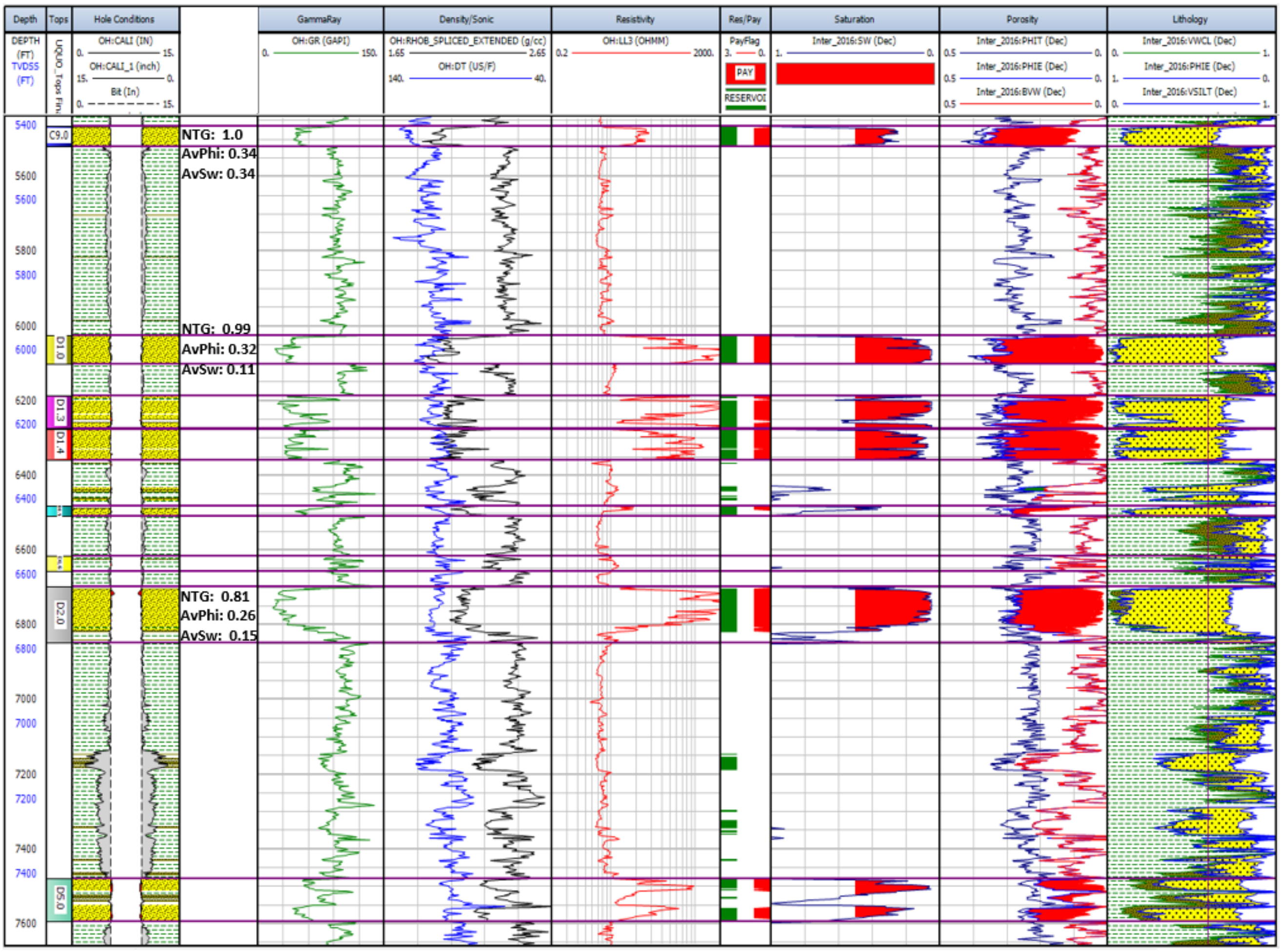


Figure 3-10 Uquo-2 petrophysical interpretation *(Source: Savannah, 2019)*

3.2.4 Uquo Field In-Place volumes

The subsurface team at CGG has independently delineated each of the reservoirs below in Minimum, P50 and Maximum cases using new depth maps, based on the 2020 reprocessed 3D PSDM seismic data. The horizon interpretations for the prospectivity, which have been converted from time to depth surfaces, have been extensively QC'd by CGG and were found to accurately describe the shape and size of the prospects. The prospect volumes are still based on the original Pre-Stack Time Migration (PSTM) data.

In addition, the following due diligence has been performed on the data and interpretations supplied, to understand:

- The effect of local use of autotracking on the seismic interpretation
- Conformance of mapped gas reservoirs to seismic Root-Mean-Square (RMS) amplitude anomalies
- Impact of smoothing pass on depth maps
- Impact of snapping to well tops, and method used, on volumes
- Checking of gas-water contacts used in all cases and their basis in evidence
- The selection of average reservoir property ranges for the volumetric analysis

Formation Volume Factors have been generated by CGG; rock properties have been derived from petrophysical analysis results and QC'd by CGG. The inputs have been run as a probabilistic Monte Carlo analysis.

In addition to a straightforward map-based volumetric determination, Savannah have also provided a 3D geocellular model based primarily on seismic maps, seismic attributes and a geological interpretation of the depositional origins of the different reservoir sands. The geological concepts used to distribute properties in three dimensions are considered technically sound and the resulting GIIP values obtained by using this approach and the seismic and facies trends are not significantly different from the simpler map-based method. The 3D model provides a solid QC of data integration and geological concepts employed and may prove useful in supporting future well planning and in understanding production performance.

RMS amplitude maps show anomalies in gas zones to a greater or lesser degree depending on reservoir intervals, these are considered good indicators.

Table 3-1 and **Table 3-2** provides the gas-initially-in-place volumes as stated by Savannah in their most recent technical report and including updates following the drilling of the Uquo-11 gas well. Comparison of CGG's independently derived map based GIIP values with those of Savannah (2021) indicates very close agreement. CGG has confirmed that the seismic interpretation carried out by Savannah is good, their volumetric assessments of GIIP can be considered sound and the stated range from P90 to P10 is also reasonable. Savannah has also presented to CGG, P/Z plot analysis which corroborates the GIIP in the D1.0 (Uquo-2 & 3 areas) and D2.0 reservoirs.

In light of this result, CGG considers that Savannah's GIIP numbers are generated according to sound technical methods and can be accepted as reasonable.

Area	Reservoir	Gross GIIP (Bscf)		
		P90	P50	P10
Uquo-2	D1.0	130.0	154.0	181.0
	D1.3/D1.4	111.0	132.0	157.0
	D2.0	105.9	132.4	155.2
	D5.0	26.4	30.8	35.6
*Sub-total**		*373.3*	*449.2*	*528.8*
Uquo-3	D1.0	270.1	322.9	371.7
	D1.3/D1.4	25.8	32.7	38.9
*Sub-total**		*295.9*	*355.6*	*410.6*
Uquo NE**	C6.0	146.0	175.0	215.0
Total*		**815.2**	**979.8**	**1,154.4**

** Arithmetic sum*

*** Uquo NE volumes on licence only*

Table 3-1 Uquo Marginal Field GIIP

In addition to the discovered volumes, CGG has reviewed the in-place numbers for the prospects in the Uquo Marginal Field Licence (**Figure 3-9**). **Table 3-3** shows Savannah's in-place volumes for the various Prospects.

Area	Reservoir	Gross GIIP (Bscf)		
		P90	P50	P10
Uquo-2	C6.5	8.1	10.0	12.0
	C9.0	32.8	39.1	46.3
*Sub-total**		*40.9*	*49.1*	*58.3*
Uquo NE	D1.0	47.5	55.1	64.5
Total*		**88.4**	**104.2**	**122.8**

**Arithmetic sum*

Table 3-2 Uquo Marginal Field: GIIP excluded from development plan

Prospect	Unrisked Gross GIIP (Bscf)			CoS (%)
	Low	Best	High	
Uquo 1SE	55.7	84.8	139.9	50
Uquo 2	5.5	15.4	39.0	73
Uquo 2W	71.3	88.4	103.7	57
Uquo 3E	151.5	221.7	335.7	35
Uquo 3S	114.8	154.3	200.1	66
Uquo 3W	72.5	115.2	204.1	18
Uquo 3 Extension	10.2	15.1	22.6	14
Uquo 3 Attic	13.3	23.4	42.6	17
Uquo 1N	6.1	14.7	35.2	18
Total*	**500.9**	**733.0**	**1,122.9**	

** Arithmetic sum*

Table 3-3 Uquo Unrisked Prospective Resources GIIP

The Chance of Success (CoS) numbers reflect the fact that the licence is in a prolific hydrocarbon-producing basin, with hydrocarbons proven in many reservoir intervals. The principal risk in the licence area is the trap, which is magnified in areas of poor imaging. Fault seal is also key to the successful trapping of many of the prospects, which at depth is particularly poorly imaged due to fault shadows. In addition, some of the traps have an increased risk associated with them as the closures extend beyond the edge of the seismic dataset. Reservoir and source are known to be low risk in the licence area and this has been reflected in Savannah's estimated CoS figures. CGG has reviewed Savannah's CoS's and deem them to be reasonable estimates. Prospects with a high CoS (> 50%) exhibit strong amplitude anomalies analogous to the producing gas reservoirs. The Uquo-3S is such a prospect (66% CoS) which is highlighted on **Figure 3-5**.

3.3 Stubb Creek Field

3.3.1 Stubb Creek Field summary

The Stubb Creek Marginal Field is located within the block OPL 276, formerly OML 14, onshore Nigeria. The Stubb Creek Field was discovered in 1971 by SPDC, who drilled 3 exploration wells and 1 appraisal well (from 1971-1983). The first well, SC-1 well intersected a 42 m gas column within the C3 sand reservoir, while light oil was later discovered in 1971 with the SC-2 well, principally within the D3 reservoir (and gas with an oil rim in the C9 reservoir). Overall, oil and gas have been discovered in 7 different 'C' and 'D' sand reservoirs in the Agbada Formation within the licence area. Where hydrocarbons are present, C sand reservoirs are typically gas-bearing apart from the C9 reservoir, with the deeper D sand reservoirs containing oil. Outlines of the main reservoirs are shown in **Figure 3-11** and **Figure 3-12**.

Stubb Creek was classified as a Marginal Field in 2002, with Universal becoming the Operator in 2003. Between 2007 and 2009, Universal drilled 5 oil development wells and one water injection well, with oil production commencing in January 2015.

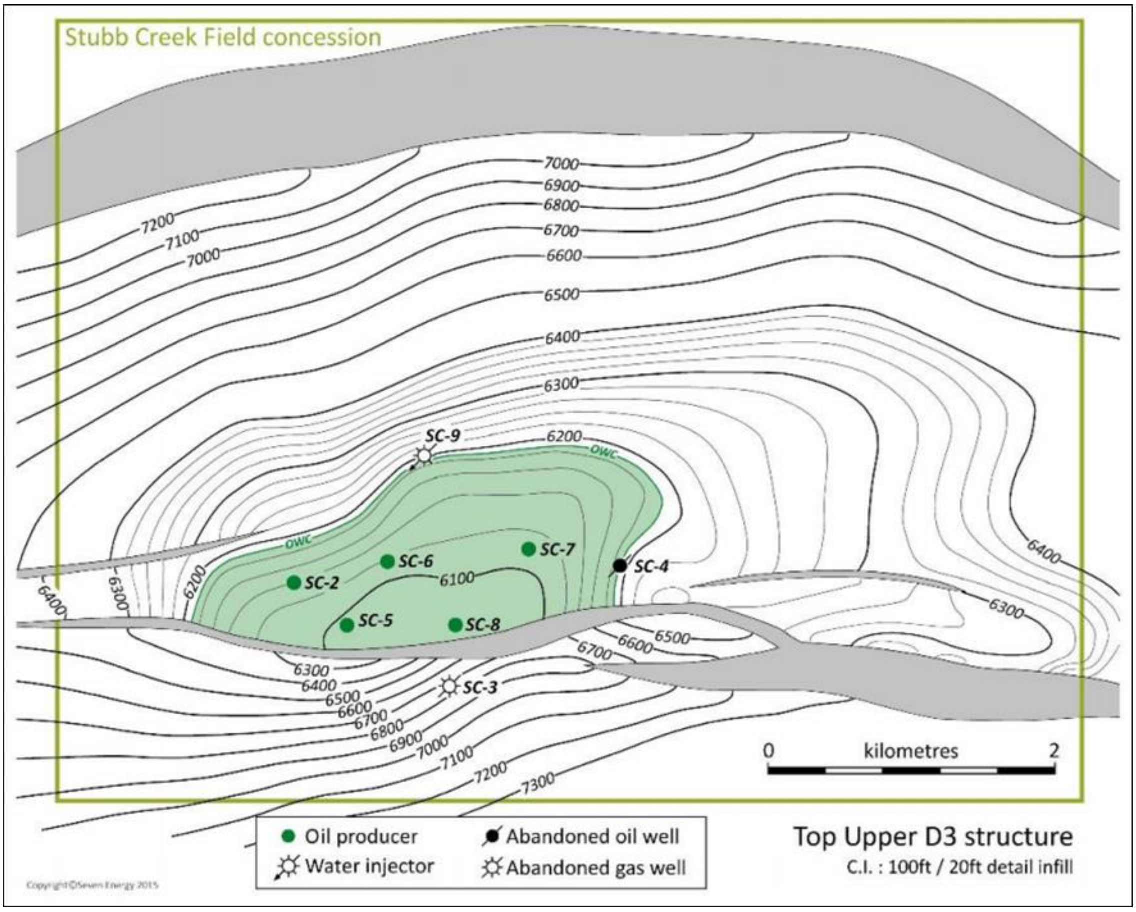


Figure 3-11 Map showing the outline of the Stubb Creek oil field at Upper D3 level *(Source: Savannah, 2019)*

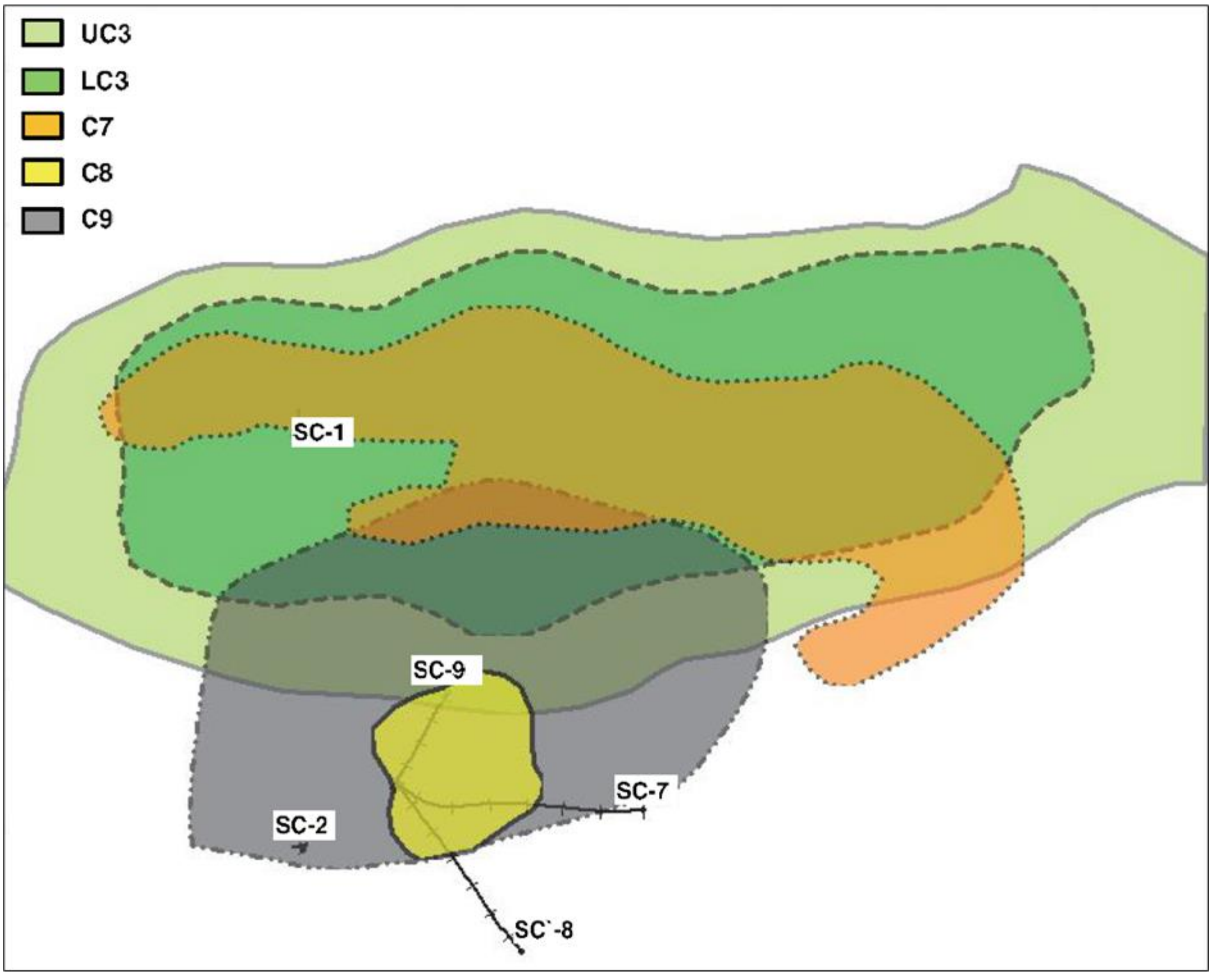


Figure 3-12 Savannah outlines of the C sand gas reservoirs *(Source: Savannah, 2019)*

3.3.2 Stubb Creek Field subsurface overview

CGG have carried out an independent analysis of the in-place volumes using a 3D seismic volume acquired in 2005/2006, which covers an area of 65 km^2. The data were supplied as a Kingdom^{TM} project containing wells (with synthetic seismograms), depth grids/horizons and fault interpretations. Composite logs were supplied which contained formation tops as well as fluid contacts which were used to delineate the tops and bases of the reservoirs and hydrocarbon columns. The data quality is generally very good; gas reservoirs are easily distinguished from the background reservoir response as would be expected in shallow, high quality gas-bearing reservoir sands. The seismic volume is a PSTM; it is CGG's opinion that the accuracy of the volumetrics shown below would be improved if the volume were to be re-processed to PSDM (Pre-Stack Depth Migration).

In addition to the Kingdom^{TM} project, Savannah has provided reports to assist with CGG's G&G analysis; these include Geoscience and Engineering studies for both C & D reservoirs.

The Stubb Creek Field is comprised of seven different hydrocarbon-bearing intervals, all of which are located within a gently dipping fault block which is downthrown to a major listric fault to the north. The main rollover structure is largely undeformed; however, there is significant E-W trending extensional faulting south of the SC-8 well, creating a series of gravity-driven low angle fault blocks as can be seen in **Figure 3-13**.

The hydrocarbon accumulations occur in a variety of different styles over a relatively small area; the hydrocarbons within the C3 reservoirs are trapped within the crest of the broad rollover anticline, whereas the C7 accumulation appears to be largely stratigraphic in nature. Many of the deeper reservoirs are footwall sands trapped against an extensional fault to the south, with additional structural relief created by the rollover anticline.

The C and D sand reservoirs of the Agbada Formation are generally of very high quality; NTG is generally in excess of 90% with porosities of 30% or higher. The C7 reservoir is anomalously poor quality, although the volumes here are relatively insignificant compared to the C3 and C9 GIIP numbers (note that the C3 accumulation appears to extend beyond the limits of the 3D seismic volume and thus may contain some upside volumes not included here). Most of the reservoirs in the survey are easily picked out on seismic, with flat spots and amplitude anomalies clearly delineating the extent of the gas accumulations (c.f. Minimum amplitude map in **Figure 3-14**). In addition to this, Savannah provided Relative Acoustic Impedance (**Figure 3-15**) and Average Energy attributes which show strong agreement with the amplitude data to support Savannah's interpretations.

The oil in the Upper D3 reservoir is light and good quality; API values are c. 42° with an average GOR of 702 scf/stb. The composition of the non-associated gas in the C sand reservoirs is unknown.

The subsurface team at CGG has completed a thorough Geological and Geophysical QC of the reports supplied by Savannah, and using the Kingdom™ project provided have independently generated P90, P50 and P10 volumes for each reservoir. This work has been supplemented by Reservoir Engineering and Petrophysics experts who have also provided inputs for the volumetrics calculations, which were run through a probabilistic Monte Carlo analysis.

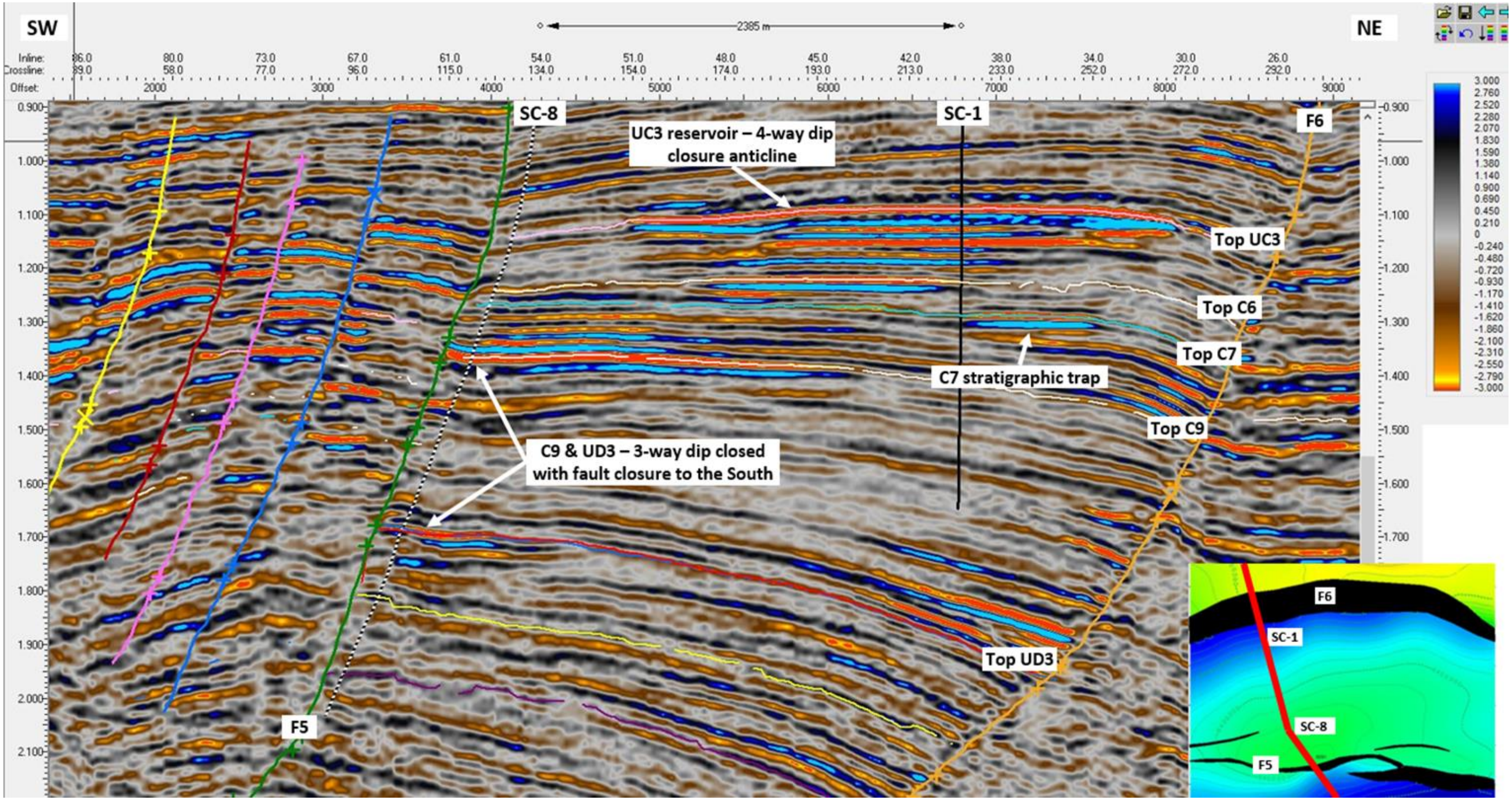


Figure 3-13 SW-NE line through Stubb Creek *(Source: Savannah, 2019)*

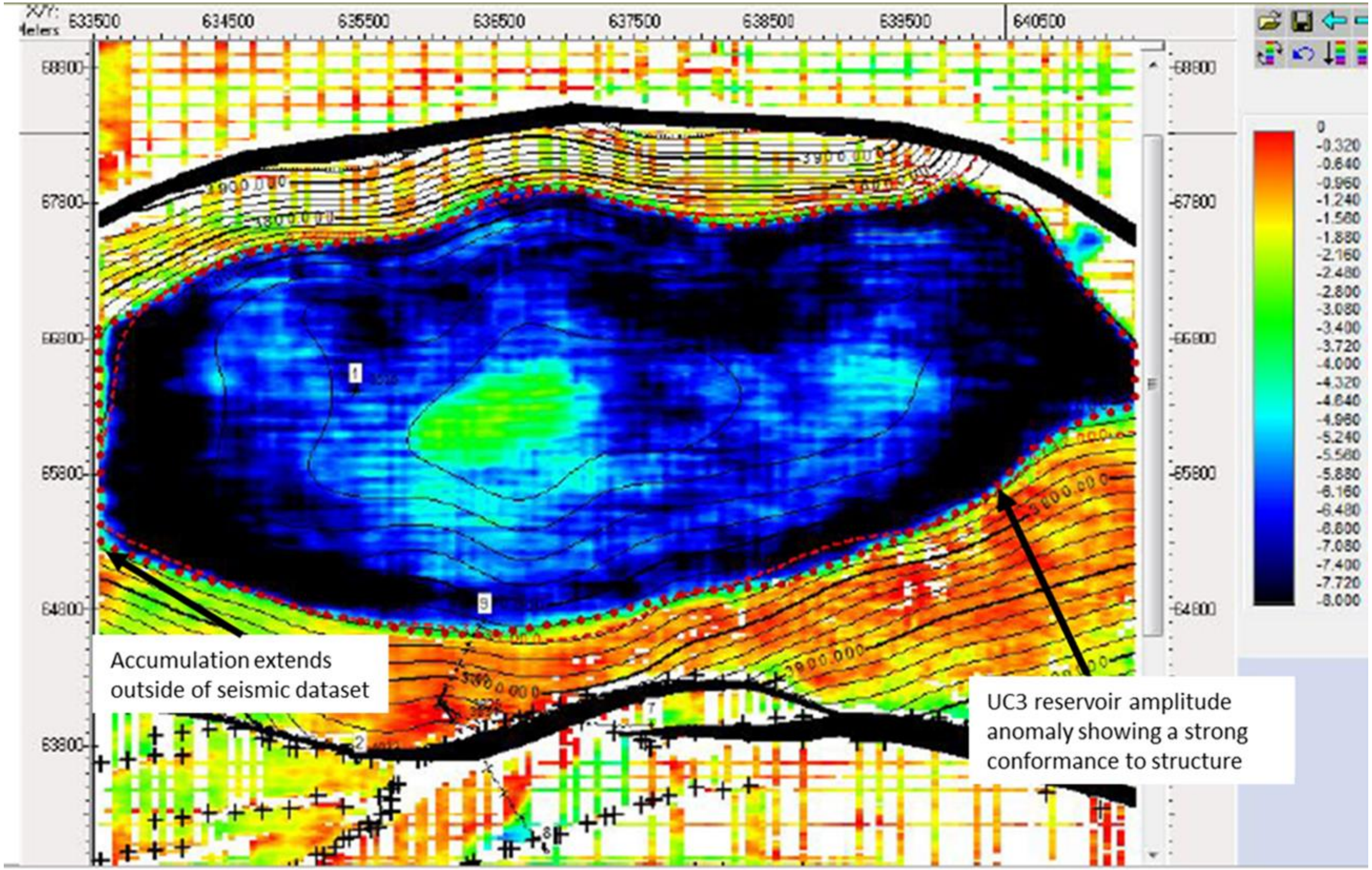


Figure 3-14 Minimum amplitude map (+/-8ms) of the UC3 reservoir *(Source: Savannah, 2019)*

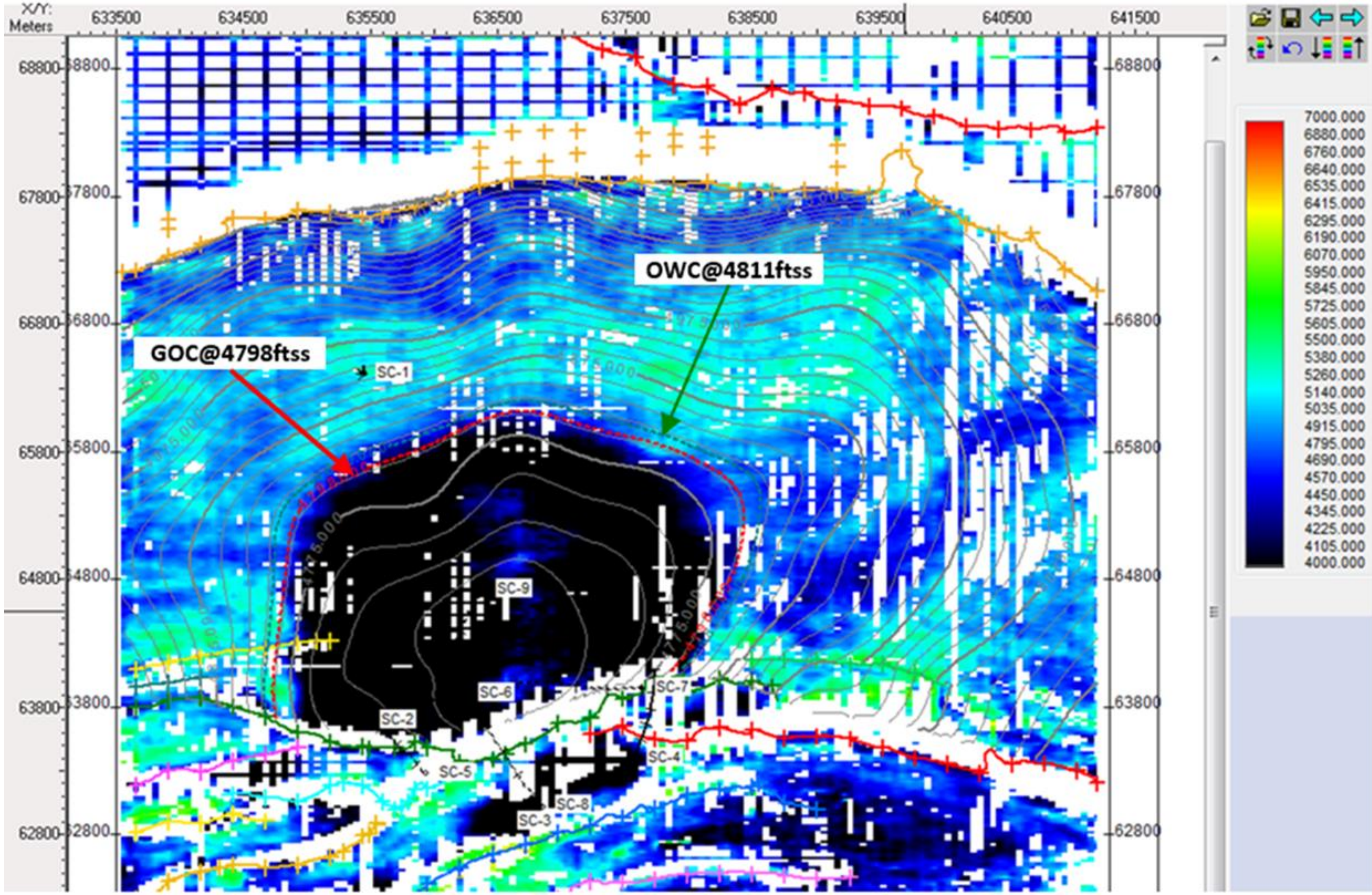
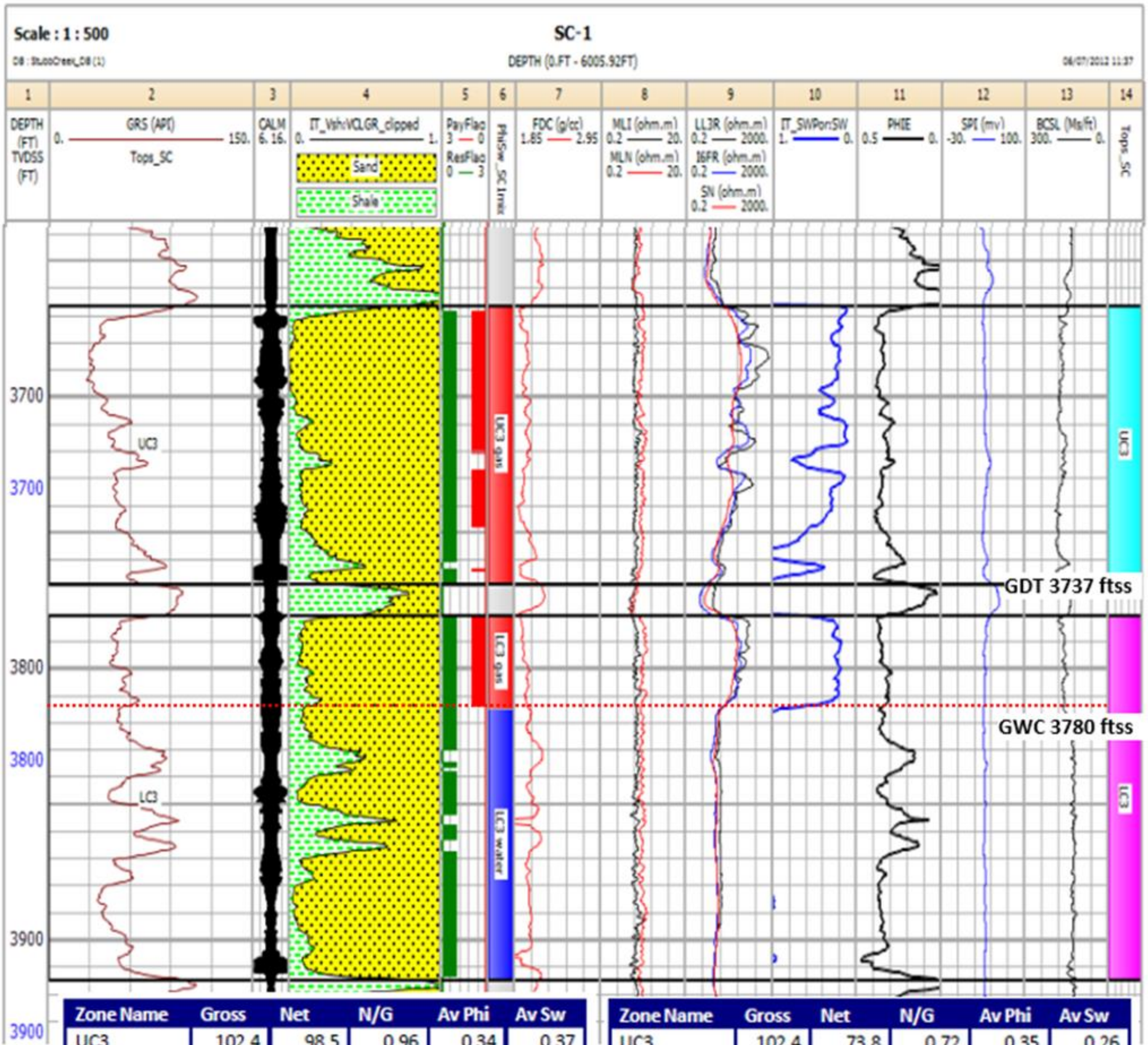


Figure 3-15 C9 Minimum Relative Acoustic Impedance map (top+8ms) - *(Source: Savannah, 2019)*

3.3.3 Stubb Creek Field petrophysics

CGG have evaluated the petrophysical data provided for the C and D sands in order to obtain P10, P50 and P90 values for the reservoir properties such as NTG (Net-To-Gross), porosity and hydrocarbon saturations. These were used as inputs for the volumetric calculations. The Volume of Clay (Vcl) was derived using a GR method (Larionov model); porosity was estimated based on the density log or sonic (SC-2 has no density log); while the Simandoux method was used to derive water saturation (Sw). The porosity cut-off of 0.1 and Vcl cut-off of 0.4 used to derive net reservoir intervals are considered to be reasonable. Fluid contacts have been determined from the petrophysical data and these have been used in combination with the DHI's and structural closures in determining the Minimum, P50 and Maximum GRV's. **Figure 3-16** and **Figure 3-17** present results from the petrophysical interpretation for the main gas (C3) and oil (UD3) reservoirs.



Zone Name	Gross	Net	N/G	Av Phi	Av Sw
UC3	102.4	98.5	0.96	0.34	0.37
LC3	134.0	119.0	0.89	0.33	0.78

SC-1 Net reservoir average properties (PHIE>0.1 & Vcl<0.4)

Zone Name	Gross	Net	N/G	Av Phi	Av Sw
UC3	102.4	73.8	0.72	0.35	0.26
LC3	134.0	32.8	0.25	0.34	0.24

SC-1 Net Pay reservoir average properties (PHIE>0.1, Vcl<0.4 & Sw<0.5)

Figure 3-16 SC-1 C3 gas reservoir petrophysical interpretation *(Source: Savannah, 2019)*

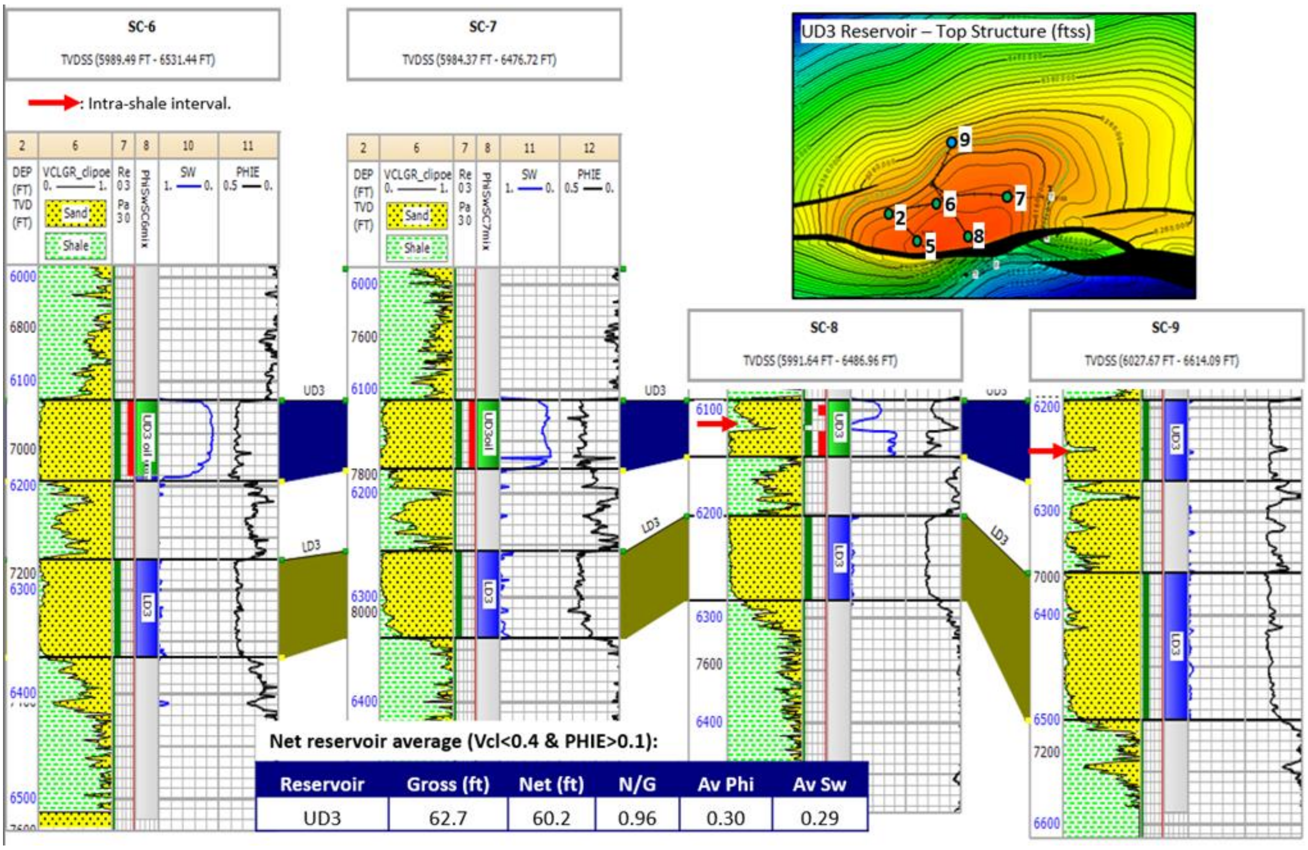


Figure 3-17 Upper D3 oil reservoir petrophysical interpretation *(Source: Savannah, 2019)*

3.3.4 Stubb Creek Field In-Place volumes

The subsurface team at CGG has independently delineated each of the reservoirs/prospects below in Minimum, P50 and Maximum cases using depth surfaces provided. The horizons interpretations which have been converted to depth surfaces have been extensively QC'd by CGG and were found to be accurate. However, as previously mentioned, CGG believe that the accuracy of the volumes would be improved by depth migrating the 3D dataset, and subsequently re-interpreting the Gross Rock Volumes of each of the accumulations/prospects. Formation Volume Factors have also been generated by CGG; rock properties have been derived from Savannah's work and QC'd by CGG's Petrophysics expert. The inputs have been run as a probabilistic Monte Carlo analysis.

Table 3-4 and **Table 3-5** tabulate in-place volumes as presented in Lloyd Register's CPR dated December 2017. CGG's independently estimated volumes were within an acceptable margin of error, and for consistency it was agreed with Savannah to remain with the previously quoted values.

Reservoir	Gross GIIP (Bscf)		
	P90	**P50**	**P10**
UC3	318.5	421.0	481.0
LC3	34.0	45.5	59.3
C6 (prospect)	13.8	19.8	27.8
C7	16.1	39.4	88.1
C8	2.6	3.9	5.6
C9	113.8	150.3	191.5
Total*	**482.4**	**656.2**	**819.9**

** Arithmetic sum, Total excludes C6 (Prospect) and C8 (too small)*

Table 3-4 Stubb Creek Marginal Field GIIP

Reservoir	Gross STOIIP (MMstb)		
	P90	**P50**	**P10**
UD3	29.9	38.9	49.6
C9*	22.4	32.6	42.5
Total**	**52.3**	**71.5**	**92.1**

**C9 oil volumes not included in reserves/resources due to difficulty in producing the thin oil rim.*
*** Arithmetic sum*

Table 3-5 Stubb Creek Marginal Field STOIIP

4 RESERVOIR ENGINEERING

A review of historical production and pressure data for the Uquo and Stubb Creek fields was carried out to confirm if performance decline has started. An update of the recoverable volume estimates and production forecasts was then conducted based on recent geological reviews carried out as part of this report.

4.1 Uquo Marginal Field

4.1.1 Overview

Gas production started in Q1 2014 in the Uquo Field with wells Uquo-2 and Uquo-4, while in Q1 2015, wells Uquo-7 and Uquo-8ST came online. In Q1 2022, the Uquo-11 well was drilled and completed as a gas producer bringing the total gas producers to five. To-date these are the only gas producing wells in the field.

Uquo-2 is producing gas from the D2.0 reservoir in the Uquo-2 area while Uquo-4 is producing gas from the D1.0 reservoir also in the Uquo-2 area. Uquo-7 and Uquo-8ST are both producing gas from the D1.0 reservoir in the Uquo-3 area. Uquo-11 currently produces gas from the D1.3/D1.4 reservoir in the Uquo-2 area with the D1.0 reservoir being behind-sleeve.

Figure 4-1 shows historical daily gas production in the field. Cumulative gas production, as at 31st December 2023, is 322.7 Bscf with associated cumulative condensate production of 0.42 MMstb.

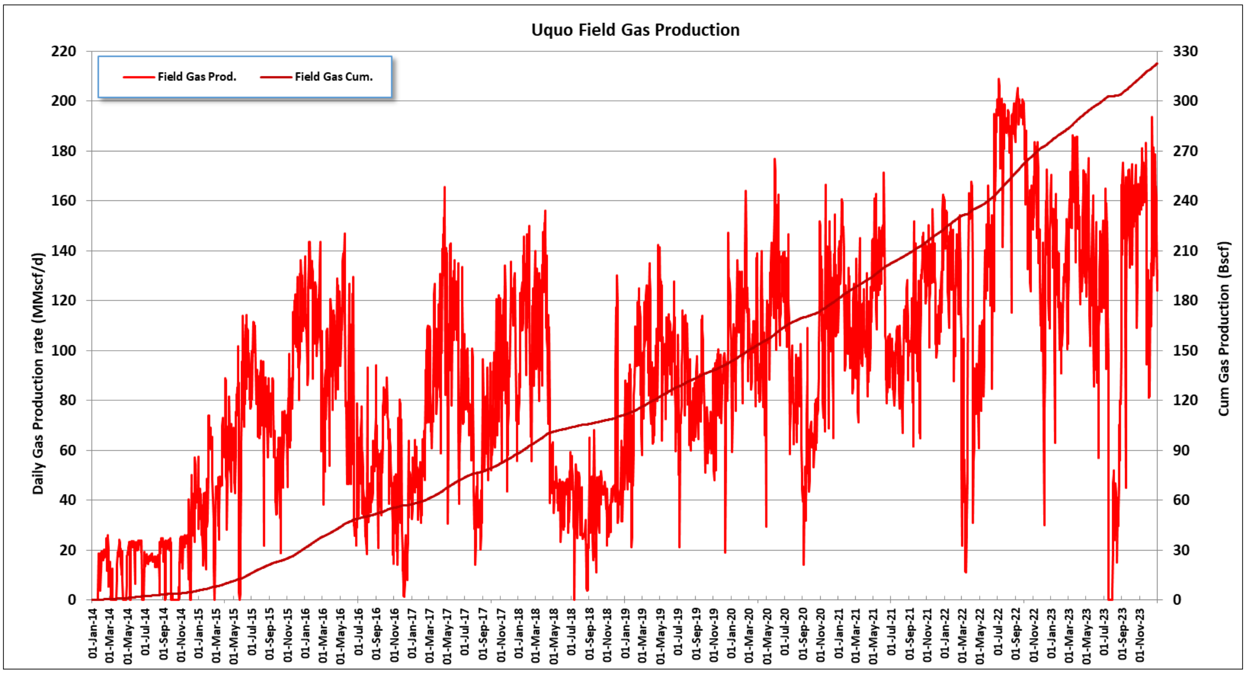


Figure 4-1 Uquo historical gas production as at 31st December 2023

A total of 3 new development wells are planned to develop the Reserves. **Table 4-1** shows the planned wells to develop the field.

Area	Reservoir	Well(s)	Comments
Uquo-2	C6.5	**-**	Contingent, not in development plan
	C9.0	-	Contingent, not in development plan
	D1.0	Uquo-4, Uquo-11	Producing, D1.0 behind-sleeve in Uquo-11
	D1.3/D1.4	Uquo-11	Producing
	D2.0	Uquo-2	Producing
	D5.0	New well 2	
Uquo-3	D1.0	Uquo-7 & Uquo-8ST	Producing
	D1.3/D1.4	New well 3	
Uquo NE	C6.0	New well 1	
	D1.0	**-**	Contingent, not in development plan

Table 4-1 Summary of Uquo Field gas reservoirs and producing/planned wells

4.1.2 Recoverable volumes and forecast

Uquo Field gas recovery factors, as shown in **Table 4-2**, were established as part of the CPR work carried out in 2019 by CGG. These have been retained in this CPR.

Savannah had performed a reservoir simulation study for the Uquo Field. The gas recovery factors estimated by the study were between c. 75% to 85%. These are based on high permeability gas reservoirs with depletion drive and assuming compression, and are deemed to be reasonable by CGG.

Case	Low	Best	High
Recovery Factor (%)	75.4	79.5	82.4

Table 4-2 Summary of Uquo Field gas recovery factors

Table 4-3 shows gas and condensate technical reserves as at 1st January 2024 in the field for the 1P, 2P and 3P cases. It should be noted that gas from D1.0, D1.3/D1.4 and D2.0 is relatively dry (approx. 97% Methane).

Area	Reservoir	Low	Best	High
Uquo-2	D1.0	130.0	154.0	181.0
	D1.3/D1.4	111.0	132.0	157.0
	D2.0	105.9	132.4	155.2
	D5.0	26.4	30.8	35.6
Uquo-3	D1.0	270.1	322.9	371.7
	D1.3/1.4	25.8	32.7	38.9
Uquo NE	C6.0*	146.0	175.0	215.0
GIIP (Bscf)	**Total****	**815.2**	**979.8**	**1,154.4**
Recovery Factor (%)		75.4	79.5	82.4
EUR (Bscf)		614.3	779.1	950.7
Cum. Prod. (as at 31st December 2023) (Bscf)		322.7	322.7	322.7
Gas Reserves Total* (Bscf)**		**291.6**	**456.3**	**628.0**
Condensate Reserves Total (MMstb)		0.41	0.64	0.88

** Uquo NE volumes on licence only*
*** Arithmetic sum, Total may not add up due to rounding*
**** Total may not add up due to rounding*

Table 4-3 Summary of Uquo Gross Technical Reserves as at 1st January 2024

Figure 4-2 shows 1P, 2P and 3P gas production profiles for the Uquo Field based on the remaining technical reserves cases outlined in **Table 4-3**. Downtime has been factored into the forecasted profiles as per the downtime allowance stipulated in the GSAs.

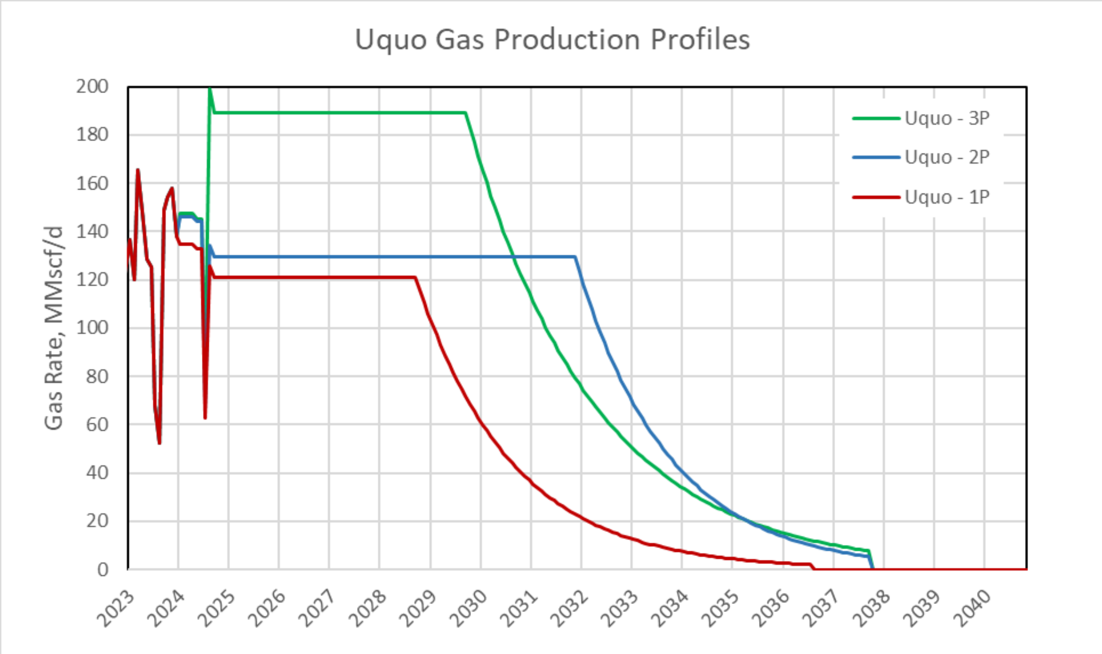


Figure 4-2 Uquo Field production forecast profiles (Reserves cases)

Table 4-4 shows a summary of the Gross Contingent Resources for the Uquo NE area plus C6.5 and C9.0 from the Uquo-2 area. CGG deem the resulting recovery factors to be reasonable for the expected drive mechanism and fluid properties.

Area	Reservoir	Contingent Resources		
		Low/1C	Best/2C	High/3C
Uquo NE	D1.0	47.5	55.1	64.5
Uquo-2	C6.5	8.1	10.0	12.0
	C9.0	32.8	39.1	46.3
Total GIIP* (Bscf)		**88.4**	**104.2**	**122.8**
Recovery Factor (%)		75.4	79.5	82.4
Contingent Resources* (Bscf)		**66.6**	**82.8**	**101.1**

** Total may not add up due to rounding*

Table 4-4 Summary of Uquo Gross Contingent Resources

Table 4-5 shows a summary of the Unrisked Gross Prospective Resources in the Uquo Field. The Prospective Resources are estimated by multiplying the recovery factors by the in-place volumes outlined in **Table 3-2**. Recovery factors ranging from 65% to 75% were used.

Prospective Resources	Low/1U	Best/2U	High/3U
GIIP (Bscf)	500.9	733.0	1,122.9
Recovery Factor (%)	65	70	75
Gas Resources (Bscf)	**325.6**	**513.1**	**842.2**

Table 4-5 Summary of Uquo Gross Unrisked Gross Prospective Resources

4.2 Stubb Creek Marginal Field

4.2.1 Overview

The Stubb Creek field is currently producing from three oil wells. The three wells which are on production are: SC-6, SC-7 and SC-8 SS (Short String) with a combined rate of around 2,000 bopd in 2023. Cumulative oil production as of 31st December 2023 is 7.2 MMstb.

Historical monthly oil production since start-up is shown in **Figure 4-3**. The processing capacity is capped at 3,000 bopd and debottlenecking of the facilities is planned to increase the production capacity to 5,000 bopd. The upgrade, planned for 2025, will enable up to two more wells, SC-2 and SC-5, to be put on-stream. The wells are already drilled and completed in the Upper D3 reservoir.

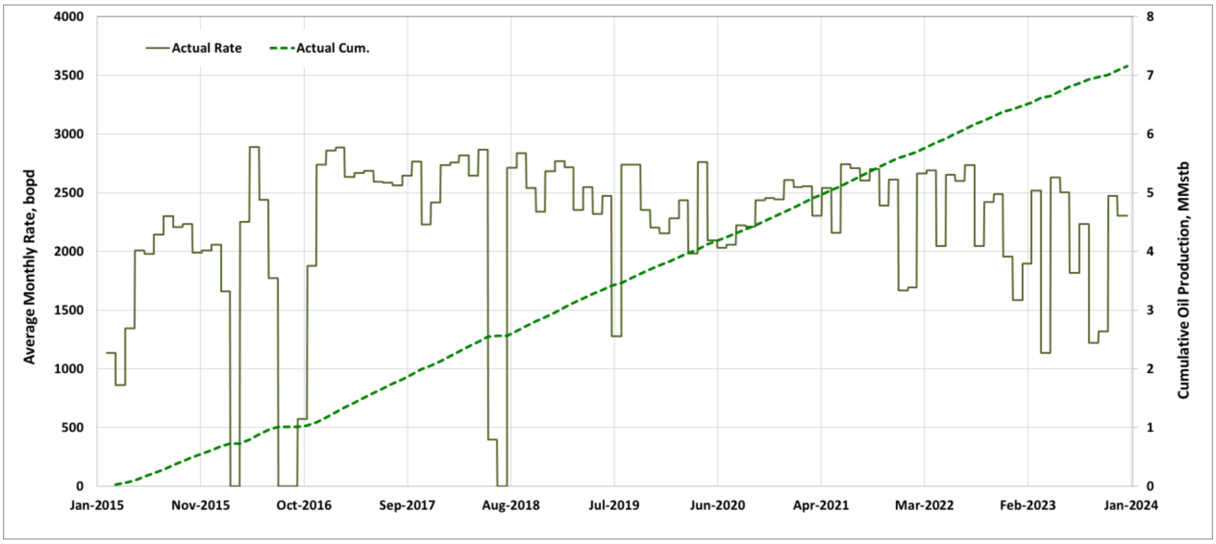


Figure 4-3 Stubb Creek field historical oil production as at 1st January 2024

4.2.2 Recovery factor

Stubb Creek recovery factors were established as part of the CPR work carried out in 2019 by CGG. These have been retained in this CPR. The drive mechanism for the UD3 reservoir is a strong aquifer drive, which is confirmed by bottom hole pressure surveys. Due to high reservoir permeability and strong water drive mechanism, the anticipated recovery factors are as shown in **Table 4-6**. CGG deem these recovery factors to be in agreement with regional analogue fields.

Case	Low	Best	High
Recovery Factor (%)	40.0	50.0	58.0

Table 4-6 Summary of Stubb Creek Field oil recovery factors

4.2.3 Recoverable volumes and forecast

Table 4-7 shows oil and solution gas Technical Reserves as at 1st January 2024 for the 1P, 2P and 3P cases.

	Low/1P	Best/2P	High/3P
STOIIP (MMstb)	**29.9**	**38.9**	**49.6**
Recovery Factor (%)	40.0	50.0	58.0
EUR (MMstb)	12.0	19.5	28.8
Cumulative Production (as at 31st December 2023)	7.2	7.2	7.2
Reserves (MMstb)	**4.8**	**12.3**	**21.6**
GOR (scf/stb)		702	
Solution gas (Bscf)	3.4	8.6	15.2

Table 4-7 Summary of Stubb Creek Field Gross Technical Reserves as at 1st January 2024

Figure 4-4 shows the production forecast profiles for Stubb Creek Field for the 1P, 2P and 3P cases. The well performance of the producing wells is used to generate production profiles with different plateau rates in each case. It is assumed that the debottlenecking of the production facility will take place in 2025 and the production will increase to c. 5,000 bopd (Proved + Probable case) by January 2025.

Since production inception, there has been minimal downtime due to production facility maintenance or wells' deliverability. However, a downtime factor of 7%, equivalent to 25 days per year, is assumed for maintenance and incorporated into the forecasted profiles.

It is also assumed that after the debottlenecking of the production facility, pre-downtime rate values of 4,500, 5,000, and 5,500 bopd of production will be achieved for the 1P, 2P, and 3P scenarios, respectively. This rate will be achieved by opening additional existing wells as required.

It should be noted that 12 ft of oil exists in the C9.0 reservoir, however due to the limited thickness of the oil leg CGG believes recovery would be challenging. Therefore, no oil Reserves or Resources have been attributed for the C9.0 reservoir.

Annual production rates for the Stubb Creek Field are tabulated in **Appendix A.**

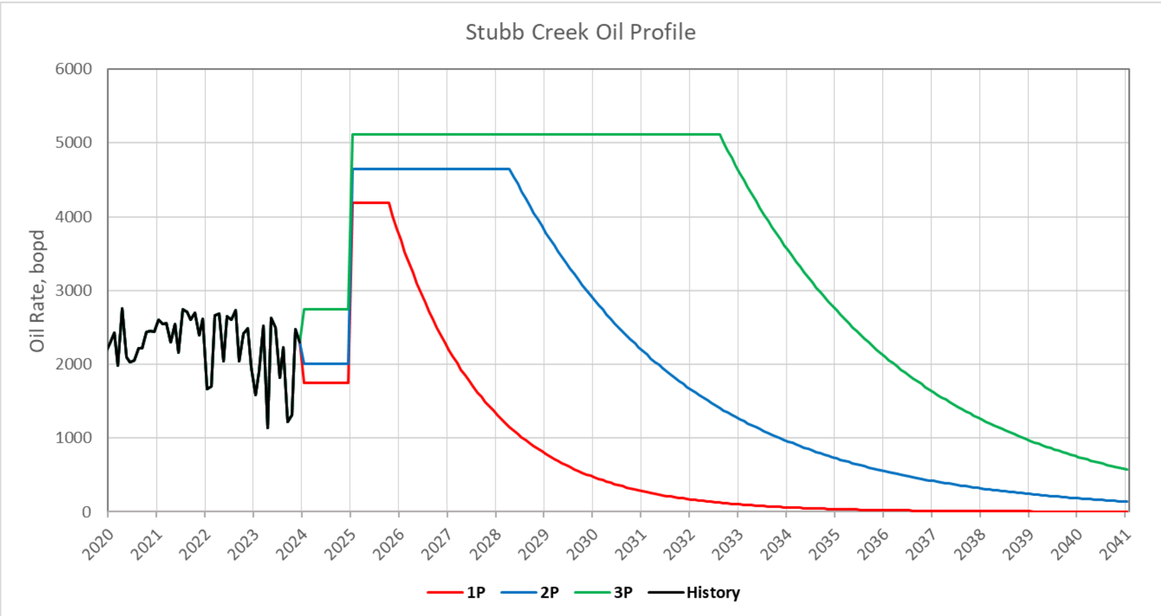


Figure 4-4 Stubb Creek production forecast profiles

A summary of Gross Gas Contingent Resources in the field is shown in **Table 4-8**. These, together with the gas in-place and gas recovery factors, were established as part of the CPR work in 2019 by CGG based on simulation studies and analogue fields, and have been retained in this CPR.

Contingent Resources	Low/1C	Best/2C	High/3C
GIIP (Bscf)	**482.4**	**656.2**	**819.9**
Recovery Factor (%)	76	78.5	83
Gas Resources (Bscf)	**364.9**	**515.3**	**680.3**

Table 4-8 Summary of Stubb Creek Field Gross Contingent Resources

It is worth noting that the Contingent Resources at Stubb Creek have a relatively high chance of commerciality (>75%) due to the excellent reservoir characteristics and definition of the accumulations based on log and seismic data (**Section 3.3**).

Unrisked Gas Prospective Resources in the field are shown in **Table 4-9**. These, together with the gas in-place and gas recovery factors, were established as part of the CPR work in 2019 by CGG and have been retained in this CPR. The range of recovery factors was based on analogue fields.

Prospective Resources	Low/1U	Best/2U	High/3U
GIIP (Bscf)	**13.8**	**19.8**	**27.8**
Recovery Factor (%)	65	70	75
Gas Resources (Bscf)	**9.0**	**13.9**	**20.9**

Table 4-9 Summary of Stubb Creek Field Gross Unrisked Prospective Resources

Contingent Resources from Stubb Creek will be developed, once the Uquo Field Reserves and Contingent Resources are not sufficient to meet the Daily Contracted Quantity (DCQ) Accugas downstream GSAs. **Figure 4-5** shows combined Reserves and Contingent Resources profiles for the Uquo and Stubb Creek fields.

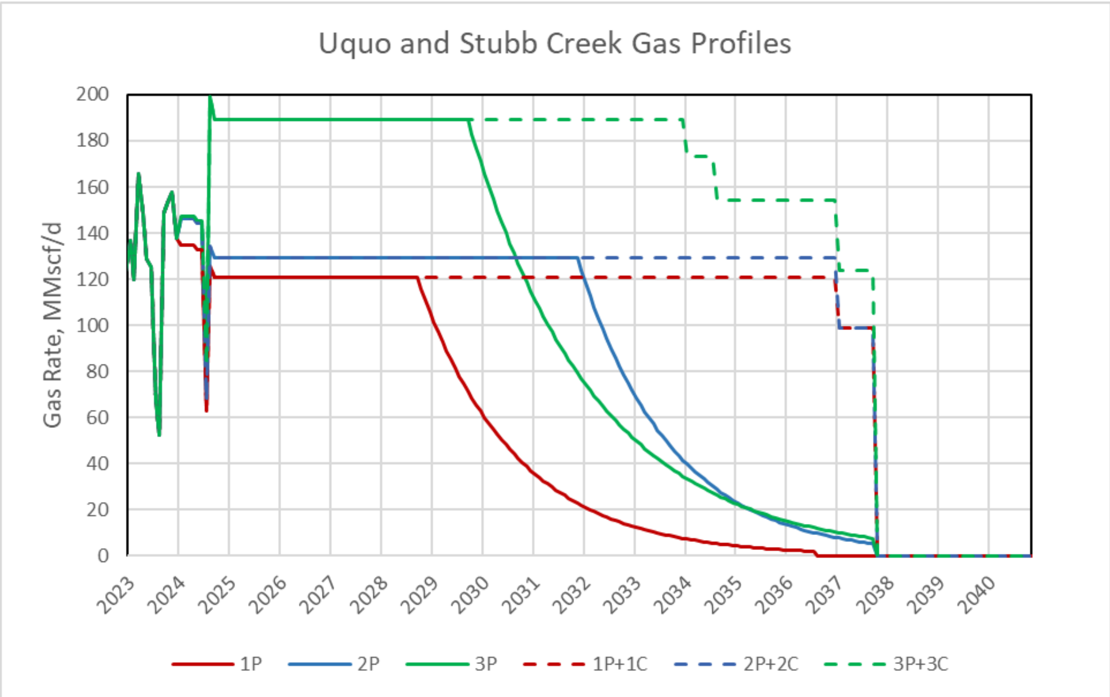


Figure 4-5 Uquo and Stubb Creek fields production forecast profiles (Reserves and Contingent Resources cases)

Annual production rates for all cases are tabulated in **Appendix A**.

5 FACILITES AND COSTS

This section presents details of the existing facilities and future development plans for the Uquo and Stubb Creek fields, and for Accugas. All costs are presented in 2023 terms unless stated otherwise.

5.1 Uquo Field

5.1.1 Existing facilities

Dedicated in-field flowlines transport produced gas individually from the producing wells owned by SEUGL to a Central Processing Facility (CPF) owned by Accugas. The gas from the Uquo Field is relatively dry (approximately 97% methane).

5.1.2 Development plans

The proposed development plan for Uquo consists of drilling three additional gas development wells.

Table 5-1 presents the work plan assumed for the 1P, 2P, 3P Reserves and 1C, 2C, 3C Contingent Resources cases. All Reserves cases assume the same work elements but with different timings.

Year	1P	2P	3P	1C	2C	3C
2024						
2025	1 water disposal well + 1 gas well	1 water disposal well	1 water disposal well + 1 gas well			
2026		1 gas well				
2027	1 gas well		2 gas wells			
2028	1 gas well	1 gas well		1 gas well		
2029		1 gas well		1 gas well		1 gas well
2030						1 gas well
2031					1 gas well	
2032					1 gas well	
2033						

Table 5-1 Uquo – Reserves and Contingent Resources well schedules

The estimated cost of each gas well is US$18 MM, comprising US$15 MM for the well itself and US$3 MM for the flowlines. The water disposal well is estimated at US$6.5 MM. The total cost is estimated to be approximately US$61 MM for each Reserves case.

An additional two wells costing US$18 MM each are assumed for the Contingent Resources cases.

These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

5.1.3 Operating costs

Long-term operating costs for Uquo Field are assessed to be US$4.0 MM per year.

5.1.4 Decommissioning costs

Gross decommissioning costs for the Reserves cases are estimated to be US$3.3 MM (2022 terms) for plugging and abandoning the wells, and decommissioning the flowlines.

5.2 Stubb Creek Field

5.2.1 Existing facilities

Dedicated in-field flowlines from each well transport production to a 3,000 bopd Early Production Facility (EPF). From the EPF crude is transported via a 23 km 6 inch pipeline to the FUN manifold, and then to the Qua Iboe Terminal. A 31 km 6 inch pipeline has also been constructed to transport produced associated gas to the Uquo CPF, which is reducing flaring.

5.2.2 Development plans

The proposed Oil development plan for Stubb Creek consists of:

- De-bottlenecking the existing production facility, to increase gross capacity from 3,000 to 5,000 bopd (2025)
- Bringing on stream up to two wells already drilled (2025)
- Drilling a water disposal well (2025)

The water disposal well may be needed, based on evidence of strong aquifer support, although there is no water production at the current time.

Total Capex for the above development plan is estimated to be US$28 MM comprising US$15 MM for the water well and US$13 MM for the production facility upgrade and water handling facilities.

For the Contingent Resources gas cases, six new wells are assumed for the 1C case, three new wells are assumed for the 2C case and four new wells are assumed for the 3C case with an estimated cost of US$18 MM per well. These cost estimates have been reviewed by CGG, and are deemed to be reasonable.

Year	1C	2C	3C
2027			
2028			
2029	1 gas well		
2030	1 gas well		1 gas well
2031			1 gas well
2032	1 gas well		
2033	2 gas wells	1 gas well	
2034	1 gas well	1 gas well	
2035			1 gas well
2036		1 gas well	1 gas well

Table 5-2 Stubb Creek – Contingent gas resources well schedules

5.2.3 Operating costs

Long-term operating costs for the oil operations are US$8.1 MM per year, and an additional US$2 MM per year for the Contingent Resources gas case. There is also a crude handling charge of US$1.37/bbl for use of the Qua Iboe Terminal.

5.2.4 Decommissioning

Gross decommissioning costs for the Reserves case are estimated to be US$16.6 MM (2022 terms) for plugging and abandoning the wells, decommissioning the flowlines and removing the production facility.

5.3 Accugas

Accugas owns and operates the midstream gas facilities associated with the Uquo and Stubb Creek fields. The principal assets comprise the Uquo CPF and the export pipelines.

The Uquo CPF, which is owned and operated by Accugas, consists of two process trains; each with a nameplate capacity of 100 MMscf/d. The CPF provides the following services:

- hydrocarbon and water dew-point control
- condensate stabilisation
- crude processing
- power generation

Gas from the CPF is currently exported through the following pipelines owned and operated by Accugas:

- a 62 km 18 inch pipeline via the Ibom Gas Receiving Facility
- a 63 km 24 inch pipeline via the Oron Tie-in to the Calabar Junction and then to the Calabar power station and the Lafarge Africa cement plant
- a 38 km 18 inch pipeline from Calabar Junction to the Lafarge Africa cement plant, which is part of the 128 km East Horizon gas pipeline, also owned by Accugas

To supply gas to industrial customers in the Port-Harcourt area, a third-party pipeline is used to transport gas from the Ibom Gas Receiving Facility.

Condensate is exported from the CPF via a third-party owned 8 km 4 inch oil pipeline to the FUN manifold and then via a 2 km 10 inch oil pipeline to the ExxonMobil operated Qua Iboe Terminal. The FUN manifold is owned by a JV of the Uquo, Stubb Creek and Qua Iboe Marginal Field Operators.

Locations and details of the CPF and the pipelines are provided in **Figure 5-1**. The Uquo CPF could accommodate an additional 100 MMscf/d process train if expansion was required and commercially justified.

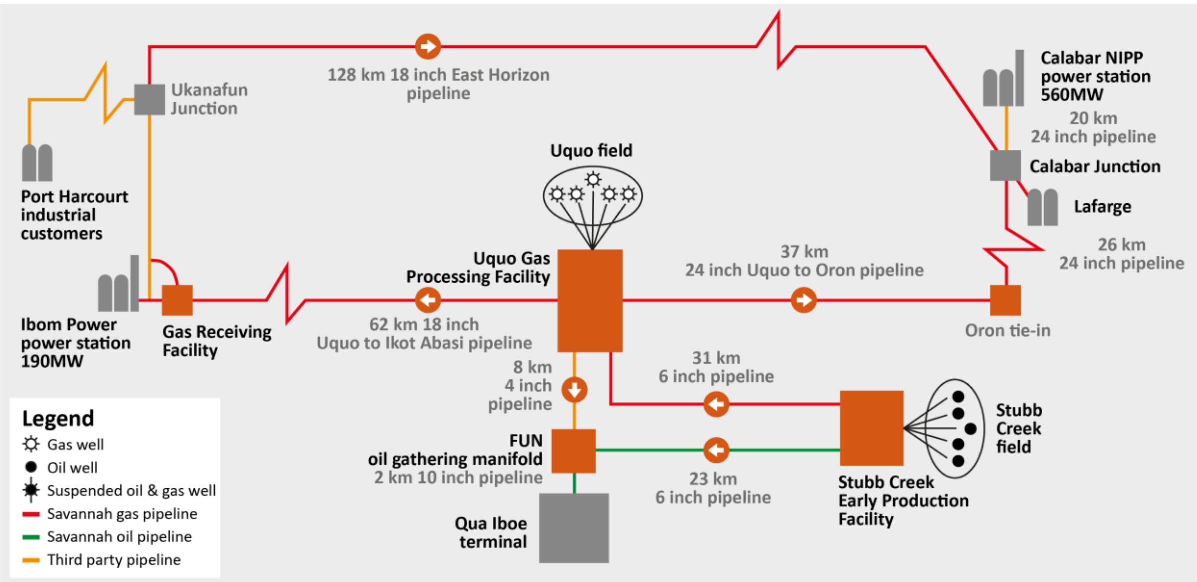


Figure 5-1 Uquo, Stubb Creek, Accugas and associated infrastructure *(Source: Savannah, 2022)*

5.3.1 Development costs

The CPF currently processes gas from the Uquo Field, but future plans are to install compression facilities and to process gas from other fields, including Stubb Creek.

Accugas has started the civil engineering phase of the compression project, while the gas compressors manufactured and successfully tested at Solar Turbine's facility in San Diego, USA are now in-country ready for installation.

The planned capex for Accugas totals US$72 MM comprising US$37 MM for pipelines, US$24 MM for compression and US$11 MM of other costs.

5.3.2 Operating costs

Long-term operating costs are estimated at US$21.3 MM. In addition, there is a crude handling charge of US$1.37/bbl for use of the Qua Iboe Terminal. Accugas will also charge a processing fee of US$4.25/bbl to Frontier on any future oil production, although this has not been included in the valuation at this stage.

5.3.3 Decommissioning costs

Gross decommissioning costs are estimated to be U$43.7 MM (2022 terms) for removal of the facilities, decommissioning of pipelines and land re-instatement.

6 ECONOMIC EVALUATION

6.1 Methodology

Net Present Values (NPVs) and economic Reserves have been calculated using Savannah's Excel™ integrated economic model of the Uquo and Stubb Creek Marginal Fields and the Accugas Midstream business. The model has been subject to a high level review by CGG and found to be in agreement with the fiscal and commercial terms applicable to the licences.

6.2 Paying and Revenue interests

Savannah has an 80% participating interest in the Uquo gas project via its indirect 80% interest in SEUGL, which has a 100% interest in the Uquo gas project.

Savannah has a 51% participating interest in the Stubb Creek Marginal Field via a 100% interest in UERL. UERL's paying interest in the field is 20% for oil and 50% for gas, and the profit interest is 35% for oil and 60% for gas.

Savannah has an 80% participating interest in the Accugas Midstream Business.

6.3 Fiscal terms

The Nigerian Marginal Field fiscal terms apply to the Uquo and Stubb Creek fields. The current terms were revised to reflect the 2021 Petroleum Industries Act (PIA), which came into force in February 2023.

The key changes include the abolition of Petroleum Profits Tax (PPT), and the introduction of both Corporate Income Tax (CIT) and Hydrocarbon Tax (HCT) for oil fields. Royalty rates were also be revised.

The key features of both the current and revised (used in the economic model) fiscal regimes for Uquo and Stubb Creek are tabulated below.

Accugas is assumed to be subject to Corporate Income Tax (CIT).

		Pre-PIA	Post-PIA
Oil Royalty			
Production based	0 – 5,000 bopd	2.5%	5%
	5,001 – 10,000 bopd	7.5%	7.5%
	10,001 – 15,000 bopd	12.5%	15.0%
	> 15,001 bopd	18.5%	15.0%
Price based	Oil price < US$50/bbl		-
	at US$100/bbl		5%
	at ≥ US$150/bbl		10%
Gas Royalty		7%	2.5%
Condensate Royalty		5%	5%
Overriding Royalty (oil)	0 – 2,000 bopd	2.5%	2.5%
	2,001 – 5,000 bopd	3.0%	3.0%
	5,001 – 10,000 bopd	5.5%	5.5%
	10,001 – 15,000 bopd	7.5%	7.5%
Education tax		2.0%	2.5%
NDDC levy		3.0%	3.0%
Host Community Trust	-		3.0%
NASENI	-		0.25%
Petroleum Profits Tax (PPT)	85%		-
Hydrocarbons Tax (HCT)[1]	-		15%
Corporate Income Tax (CIT)[2]	30%		30%

Note: 1. Applies to oil only, 2. Applies to oil and gas

Table 6-1 Summary of fiscal terms

Taxes have been adjusted to allow for brought forward capital allowances and tax losses.

6.4 Oil prices

Oil production from Stubb Creek is sold to ExxonMobil at the Qua Iboe Terminal. It is assumed that the price achieved is at a US$1.25/bbl premium to Brent based on historic prices. Condensate is commingled with processed crude and sold at the same premium to Brent.

The base Brent price assumption in the evaluation assumes real prices of US$80/bbl for 2024, and US$65/bbl in 2025 and beyond. From January 2024, the price is escalated at 2.5% per year.

Sensitivity cases at fixed prices of US$60/bbl, US$70/bbl, US$80/bbl, US$90/bbl and US$100/bbl have also been analysed, with the price inflated at 2.5% per year from January 2024.

6.5 Gas prices

Gas from the Uquo Field is sold to Accugas under the Upstream GSA. The contract runs until the end of December 2028, and thereafter is extendable to the end of the Uquo Field life.

The upstream nominal gas prices assumed by year in the economic model are tabulated below.

	2024	2025	2026	2027	2028	2029	2030	2031
Gas price (US$/Mscf)	1.83	1.83	2.35	2.39	2.43	2.48	2.53	2.58

Table 6-2 Upstream nominal gas price assumed in the economic model

Accugas sells processed gas under Downstream GSAs to the Calabar power plant and to the Lafarge cement factory. The DCQ (Daily Contracted Quantity) is 155.2 MMscf/d with a Take or Pay (ToP) of 80% of the DCQ.

Additional smaller volumes are also contracted under short-term interruptible GSAs with SNG, SPDC, Notore, and CHGC. The key terms for the GSAs are tabulated below.

	Length of contract	Start date	Contract end	DCQ	Take or Pay (ToP)
Calabar Power Plant	20 years	Sep-17	Sep-37	131.0 MMscf/d	80% of DCQ
Lafarge Africa Plc (was Unicem Cement Plant)	25 years	Jan-12	Jan-37	24.19 MMscf/d	80% of DCQ
CHGC (an Axxela subsidiary)	1-year initial term extended by 12 months	Jun-22	Jun-24	Nominations up to 10 MMscf/d	N/A
Notore	1-year initial term extended by 12 months	Aug-22	Aug-24	Nominations up to 10 MMscf/d	N/A
The Shell Petroleum Development Company of Nigeria (SPDC)	6-month initial period extended	Jun-22	Apr-24	Nominations up to 3 MMscf/d	N/A
Shell Nigeria Gas Limited (SNG)	6-month initial period extended by 6 months	Jun-23	June-24	Nominations up to 3 MMscf/d	N/A

Table 6-3 Details of Downstream GSA's

The average downstream nominal gas price assumed by year across the contracts in the economic model is tabulated below.

	2024	2025	2026	2027	2028	2029	2030	2031
Gas price (US$/Mscf)	4.8	5.0	5.1	5.2	5.3	5.4	5.5	5.6

Table 6-4 Downstream average nominal gas price assumed in the economic model

6.6 Other assumptions

The following assumptions have also been used by CGG.

Parameter	Value
Discount Rate	10%
Discount Methodology	Monthly
Cost/Price Inflation	2.5% per annum
Valuation Date	1st January 2024

Table 6-5 Economic parameters

6.7 Economic results

The following section presents results from the economic analyses for the upstream and midstream assets.

It should be noted that the estimated Net Present Values (NPVs) may be subject to significant variation with time as assumptions change, and that they are not deemed to represent the market value of the assets.

The NPVs include the effect of brought forward unused capital allowances and tax losses on future tax liabilities, but do not include any balance sheet assets or liabilities at the evaluation date.

6.7.1 Upstream Assets

The NPVs of the future cash flows derived from the exploitation of the Reserves are tabulated below. The values stated are net to Savannah's interest and after deduction of Royalties and Taxes. The Uquo NPVs assume that the GSA counterparties nominate and take gas volumes in accordance with the relevant ToP profiles.

NPV10 (US$MM) of Reserves Net to Savannah			
	Proved	**Proved & Probable**	**Proved, Probable & Possible**
Uquo (gas and condensate)	217.9	329.4	418.3
Stubb Creek oil	44.0	109.9	168.4
Total	**261.8**	**439.4**	**586.7**

Table 6-6 NPV10 (US$MM) of Reserves Net to Savannah as at 1st January 2024

Sensitivities have been calculated for total NPV for variations in oil price, Capex and Opex. The results of this analysis are tabulated below for the Proved & Probable case.

NPV10 (US$MM) Net to Savannah			
	Uquo	**Stubb Creek**	**Total***
Base case (Proved+Probable)	329.4	109.9	439.4
Oil price - US$60/bbl	327.7	100.4	428.1
Oil price - US$70/bbl	330.1	115.4	445.5
Oil price - US$80/bbl	332.5	129.8	462.3
Oil price - US$90/bbl	334.9	143.8	478.7
Oil price - US$100/bbl	337.3	157.2	494.5
Capex +10%	326.6	109.4	435.9
Capex -10%	332.3	110.5	442.8
Opex +10%	327.8	108.5	436.3
Opex -10%	331.3	111.3	442.7

* Total may not add up due to rounding

Table 6-7 Proved and Probable NPV10 (US$MM) sensitivities as at 1st January 2024

6.7.2 Midstream Assets (Accugas)

The Net Present Values (NPV) of the future cash flows accruing to the Accugas Midstream Business have been extracted from Savannah's integrated economic model and are tabulated below for the Proved & Probable (2P) plus Contingent (2C) case. The model has been subject to a high level review by CGG, and found to be in reasonable agreement with the applicable fiscal and commercial terms. The values stated are for the Accugas Midstream Business (100%) and for Savannah's net 80% interest after deduction of taxes. The gas sold by Accugas is assumed to be sourced from Uquo, with additional gas derived from Stubb Creek. Potential other sources, such as third party gas fields, are not included in the valuation.

Case	Accugas (100%)	Net to Savannah
Base Case (2P+2C)	795.3	636.3

Table 6-8 Accugas NPV10s (US$MM) as at 1st January 2024

It should be noted that there are no gas Reserves or Resources associated with Accugas.

6.7.3 Upstream and Midstream Financial Forecasts

Table 6-9 shows the annual financial forecasts net to Savannah for the Upstream Assets and the Midstream Assets, including annual production/volumes.

	Total Upstream			Total Midstream (Accugas)		
	Gross Production (Kboepd)	Revenue (US$MM)	FCF (US$MM)	Gross Volumes (Kboepd)	Revenue (US$MM)	FCF (US$MM)
2024	24.3	94.5	57.4	22.1	187.4	72.1
2025	26.4	111.5	71.0	21.5	192.1	98.7
2026	26.4	131.7	73.1	21.5	195.0	82.2
2027	26.4	134.2	89.2	21.5	198.6	83.8
2028	26.1	134.5	69.6	21.5	202.4	85.2
2029	25.1	128.2	61.0	21.5	205.1	85.7
2030	24.3	123.1	74.2	21.5	208.8	86.9
2031	23.6	119.1	72.1	21.5	212.7	88.3

Table 6-9 Annual financial forecasts net to Savannah for the Upstream Assets and the Midstream Assets

The total Upstream Opex and Capex per barrel of oil equivalent produced over the 2023-2031 period is estimated at US$1.7/boe and US$1.3/boe, respectively.

The total Midstream Opex and Capex per barrel of oil equivalent delivered by Accugas over the 2023-2031 period is estimated at US$3.3/boe and US$0.6/boe, respectively.

7 APPENDIX A: PRODUCTION PROFILES

Gross Production Profiles: Uquo Field

	Uquo Field											
	Gas (MMscf/d)			Condensate (bopd)			Gas (MMscf/d)			Condensate (bopd)		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2024	123.2	132.7	159.8	172.5	185.8	223.7	-	-	-	-	-	-
2025	120.9	129.3	189.1	169.3	181.0	264.8	-	-	-	-	-	-
2026	120.9	129.3	189.1	169.3	181.0	264.8	-	-	-	-	-	-
2027	120.9	129.3	189.1	169.3	181.0	264.8	-	-	-	-	-	-
2028	118.4	129.3	189.1	165.8	181.0	264.8	2.5	-	-	3.5	-	-
2029	80.7	129.3	186.1	113.0	181.0	260.5	39.8	-	3.0	55.7	-	4.2
2030	47.8	129.3	138.7	66.9	181.0	194.2	44.6	-	49.1	62.5	-	68.8
2031	28.3	128.8	93.0	39.6	180.3	130.2	31.3	0.5	57.1	43.9	0.7	80.0
2032	16.7	93.2	62.3	23.4	130.4	87.2	22.0	36.1	45.9	30.8	50.6	64.3
2033	9.9	54.1	41.8	13.9	75.7	58.5	15.4	60.9	36.9	21.6	85.2	51.7
2034	5.9	31.4	28.0	8.2	43.9	39.2	10.8	47.7	29.7	15.2	66.7	41.6
2035	3.5	18.2	18.8	4.9	25.5	26.3	7.6	36.7	23.9	10.7	51.4	33.5
2036	1.3	10.6	12.6	1.9	14.8	17.6	5.3	28.2	19.2	7.5	39.5	26.9
2037	-	4.9	6.6	-	6.9	9.3	2.9	16.8	11.9	4.1	23.5	16.7

Gross Production Profiles: Stubb Creek Field

	Stubb Creek Field											
	Oil (bopd)			Gas (MMscf/d)			Gas (MMscf/d)			Condensate (bopd)		
	1P	2P	3P	1P	2P	3P	1C	2C	3C	1C	2C	3C
2024	1,750	2,000	2,750	1.2	1.4	1.9	-	-	-	-	-	-
2025	4,142	4,650	5,115	2.9	3.3	3.6	-	-	-	-	-	-
2026	2,935	4,650	5,115	2.1	3.3	3.6	-	-	-	-	-	-
2027	1,751	4,650	5,115	1.2	3.3	3.6	-	-	-	-	-	-
2028	1,045	4,349	5,115	0.7	3.1	3.6	-	-	-	-	-	-
2029	623	3,343	5,115	0.4	2.3	3.6	0.4	-	-	0.7	-	-
2030	372	2,538	5,115	0.3	1.8	3.6	28.5	-	1.3	57.1	-	2.6
2031	222	1,927	5,115	0.2	1.4	3.6	61.3	-	39.0	122.7	-	78.1
2032	132	1,463	5,026	0.1	1.0	3.5	82.2	-	80.9	164.4	-	161.7
2033	79	1,110	4,085	0.1	0.8	2.9	95.6	14.4	110.4	191.2	28.7	220.8
2034	47	843	3,149	0.0	0.6	2.2	104.2	50.2	107.5	208.4	100.5	214.9
2035	28	640	2,428	0.0	0.4	1.7	109.8	74.4	111.4	219.7	148.8	222.8
2036	17	486	1,871	0.0	0.3	1.3	114.3	90.5	122.3	228.5	181.0	244.5
2037	10	369	1,443	0.0	0.3	1.0	71.4	52.6	74.3	142.7	105.2	148.7
2038	6	280	1,112	0.0	0.2	0.8	-	-	-	-	-	-
2039	4	212	857	0.0	0.1	0.6	-	-	-	-	-	-
2040	2	161	661	0.0	0.1	0.5	-	-	-	-	-	-

8 APPENDIX B: DEFINITIONS

8.1 Definitions

The petroleum reserves and resources definitions used in this report are those published by the Society of Petroleum Engineers and World Petroleum Congress in June 2018, supplemented with guidelines for their evaluation, published by the Society of Petroleum Engineers in 2001 and 2007. The main definitions and extracts from the SPE Petroleum Resources Management System (June 2018) are presented below.

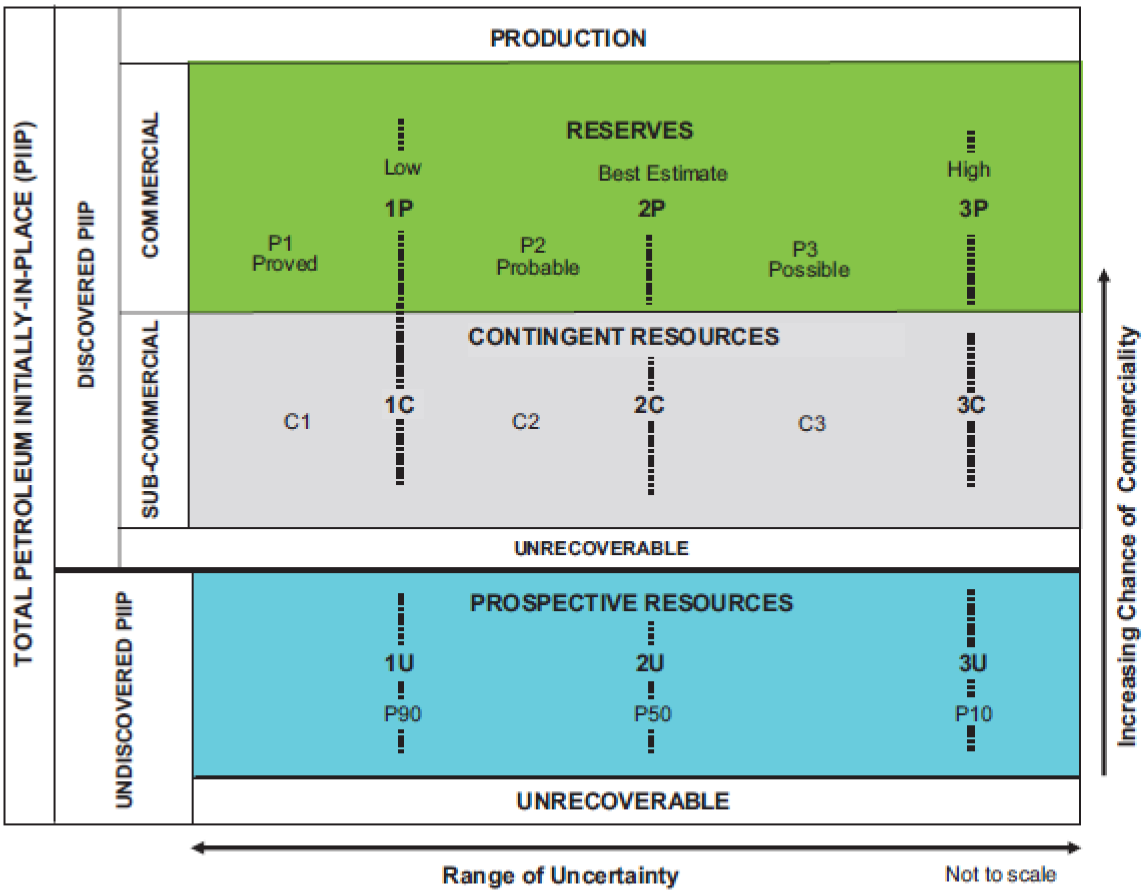


Figure 8-1 Resources Classification Framework

(Source: SPE Petroleum Resources Management System 2018)

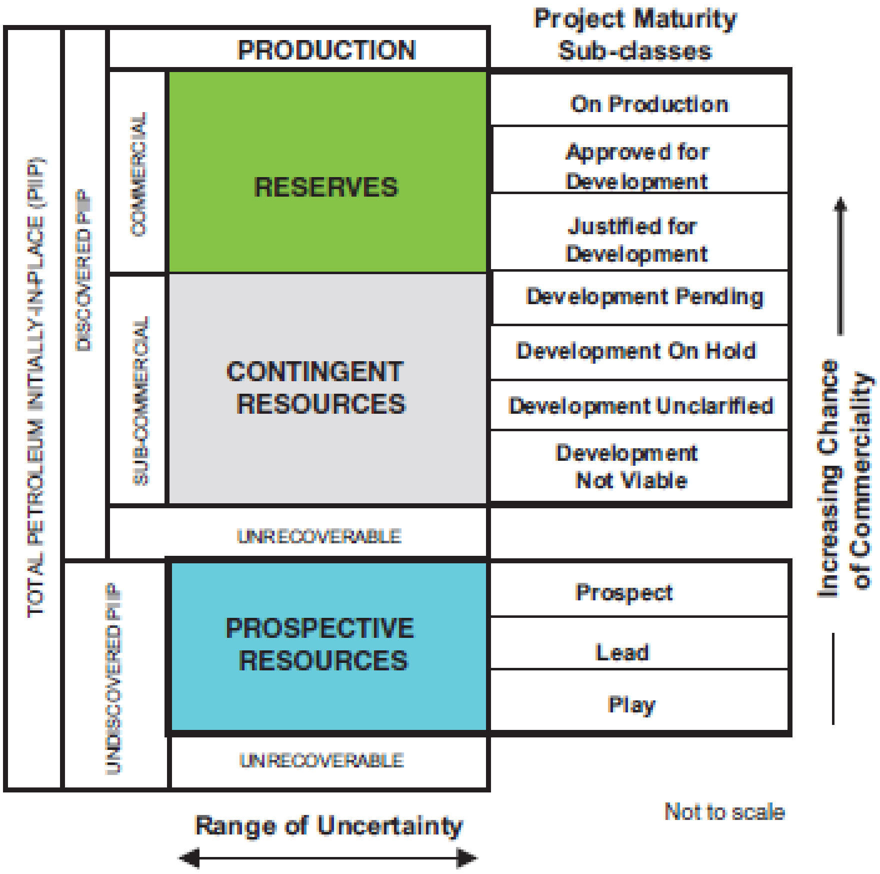


Figure 8-2 Resources Classification Framework: Sub-classes based on project maturity

(Source: SPE Petroleum Resources Management System 2018)

8.1.1 Total Petroleum Initially-In-Place

Total Petroleum Initially-In-Place (PIIP) is all quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, discovered and undiscovered, before production.

8.1.2 Discovered Petroleum Initially-In-Place

Quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production. Discovered PIIP may be subdivided into commercial, sub-commercial, and the portion remaining in the reservoir as Unrecoverable.

8.1.3 Undiscovered Petroleum Initially-In-Place

Undiscovered Petroleum Initially-In-Place PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

8.2 Production

Production is the cumulative quantities of petroleum that have been recovered at a given date. While all recoverable resources are estimated, and production is measured in terms of the sales product specifications, raw production (sales plus non-sales) quantities are also measured and required to support engineering analyses based on reservoir voidage.

8.3 Reserves

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

Reserves are recommended as sales quantities as metered at the reference point. Where the entity also recognizes quantities consumed in operations (CiO), as Reserves these quantities must be recorded separately. Non-hydrocarbon quantities are recognized as Reserves only when sold together with hydrocarbons or CiO associated with petroleum production. If the non-hydrocarbon is separated before sales, it is excluded from Reserves.

8.3.1 Developed Producing Reserves

Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate.

8.3.2 Developed Non-Producing Reserves

Developed Non-Producing Reserves include shut-in and behind-pipe reserves with minor costs to access.

8.3.3 Undeveloped Reserves

Undeveloped Reserves are quantities expected to be recovered through future investments such as

(1) From new wells on undrilled acreage in known accumulations,
(2) From deepening existing wells to a different (but known) reservoir,
(3) From infill wells that will increase recovery
(4) Where a relatively large expenditure (e.g., when compared to the cost of drilling and completing a new well) is required to recomplete an existing well.

8.3.4 Proved Reserves

Proved Reserves are those quantities of Petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from known reservoirs and under defined technical and commercial conditions.

If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

8.3.5 Probable Reserves

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P).

In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

8.3.6 Possible Reserves

Possible Reserves are those additional Reserves that analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high-estimate scenario.

When probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves that are located outside of the 2P area (not upside quantities to the 2P scenario) may exist only when the commercial and technical maturity criteria have been met (that incorporate the Possible development scope). Standalone Possible Reserves must reference a commercial 2P project (e.g., a lease adjacent to the commercial project that may be owned by a separate entity), otherwise stand-alone Possible is not permitted.

8.4 Contingent Resources

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies.

Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be sub-classified based on project maturity and/or economic status.

Projects classified as Contingent Resources have their sub-classes aligned with the entity's plan to manage its portfolio of projects. Thus, projects on known accumulations that are actively being studied, undergoing feasibility review, and have planned near-term operations (e.g., drilling) are placed in Contingent Resources Development Pending, while those that do not meet this test are placed into either Contingent Resources On Hold, Unclarified, or Not Viable.

For Contingent Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1C/2C/3C quantities, respectively. The terms C1, C2, and C3 are defined for incremental quantities of Contingent Resources.

1C denotes low estimate scenario of Contingent Resources
2C denotes best estimate scenario of Contingent Resources
3C denotes high estimate scenario of Contingent Resources

8.4.1 Contingent Resources: Development Pending

Contingent Resources Development Pending is discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future. It is project maturity sub-class of Contingent Resources.

8.4.2 Contingent Resources: Development Un-Clarified/On Hold

Contingent Resources ((Development Un-Clarified / On Hold) are a discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.

The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status.

The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.

8.4.3 Contingent Resources: Development Unclarified

A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information. The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development.

This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future
evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.

8.4.4 Contingent Resources: Development Not Viable

A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.

The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions.

The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.

8.5 Prospective Resources

Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.

Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.

For Prospective Resources, the general cumulative terms low/best/high estimates are used to estimate the resulting 1U/2U/3U quantities, respectively.

1U denotes low estimate scenario of Prospective Resources
2U denotes best estimate scenario of Prospective Resources
3U denotes high estimate scenario of Prospective Resources

8.5.1 Prospect

A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target. Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.

8.5.2 Lead

A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.

8.5.3 Play

A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.

Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

8.5.4 Unrecoverable Resources

Unrecoverable Resources are that portion of Discovered or Undiscovered Petroleum Initially-in-Place that is assessed, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered owing to physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

9 APPENDIX C: NOMENCLATURE

API	American Petroleum Institute
bbl	barrel
Bscf	billion standard cubic feet
BHT	bottom hole temperature
BHP	bottom hole pressure
boe	barrel of oil equivalent
bopd	barrels per day
Btu	British thermal unit
c.	circa
CO_2	carbon dioxide
1-D, 2-D, 3-D	1-, 2-, 3-dimensions
DHI	direct hydrocarbon indicators
DST	drill-stem test
E & P	exploration & production
e.g.	for example
et al.	and others
EUR	estimated ultimately recoverable
FCF	free cashflow
G & A	general & administration
G & G	geological & geophysical
g/cm^3	grams per cubic centimetre
GIIP	gas initially in place
GOC	gas-oil contact
GOR	gas to oil ratio
GR	gamma ray (log)
GWC	gas-water contact
HI	hydrogen index
Kbopd	thousands of barrels oil per day
Kboepd	thousands of barrels oil equivalent per day
kg	kilogram
km	kilometre
km^2	square kilometres
M & A	mergers & acquisitions
m	metre
MM	million
Ma	million years (before present)
Mscf	thousand standard cubic feet
mD	millidarcies
MD	measured depth
MFS	maximum flooding surface
MMstb	million stock tank barrels
MMbbl	million barrels
MMboe	million barells of oil equivalent
MMscf/d	million standard cubic feet per day
mSS	metres subsea
Myr	Million year
m/s	metres per second
msec	millisecond(s)
MSL	mean sea level
NaCl	sodium chloride
NPV	net present value
no.	number (not #)
OWC	oil-water contact
1P	proved
2P	proved + probable
3P	proved + probable + possible
P & A	plugged & abandoned
perm.	permeability
pH	-log H ion concentration
Ø	porosity
plc	public limited company
por.	Porosity
ppm	parts per million
PRMS	Petroleum Resource Management System (SPE)
psi	pounds per square inch
RFT	repeat formation test
RT	rotary table
SCAL	special core analysis
scf	standard cubic feet
SPE	Society of Petroleum Engineers
SS	sub-sea
ST	sidetrack (well)
stb	stock tank barrel
std. dev.	standard deviation
STOIIP	stock tank oil initially in place
Sw	water saturation
Tscf	trillion standard cubic feet
TD	total depth
TVD	true vertical depth
TVDSS	true vertical depth subsea
TWT	two-way time
US$	US dollar
US$MM	Millions of US dollars
WHFP	wellhead flowing pressure
WHSP	wellhead shut-in pressure
wt%	percent by weight

- 1 boe = 6000 scf
- 1 scm = 35.3147 scf