Competent Person's Report (CPR) Tullow Oil Equatorial Guinea Assets

Effective Date: October 1st 2020

Tullow Oil

This report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, in particular the 2018 SPE PRMS. Estimates of hydrocarbon reserves and resources should be regarded only as estimates that may change as further production history and additional information become available. Not only are reserves and resource estimates based on the information currently available, these are also subject to uncertainties inherent in the application of judgemental factors in interpreting such information. TRACS International Limited shall have no liability arising out of or related to the use of the report.

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Approved by:

M.C. Wynne (Project Manager)

Executive Summary

TRACS was commissioned by Tullow Oil to complete a Competent Person's Report (CPR) for the Equatorial Guinea assets in the Tullow Portfolio in accordance with Reserves and Resource definitions presented in the SPE's Petroleum Resources Management System.

The Equatorial Guinea fields are located offshore Equatorial Guinea in northeastern Block G on the edge of the present day continental shelf in water depths ranging from 50-850 metres.

The fields reviewed as part of this CPR are listed below:

Licence	Field
Okume Complex	Elon
	Okume
	Oveng
	Akom North
	Ebano
Ceiba	Ceiba

Ceiba and Okume Complex licences are operated under a Production Sharing Contract (PSC). Trident is the Operator of both licences; in addition to Tullow, other partners include Kosmos Energy and the State. Tullow have an exploration and development working interest of 15% and a revenue working interest of 14.25%.

The main reservoir intervals of the Ceiba field and Okume Complex fields consist of stacked deepwater turbidite channel and overbank deposit reservoirs of Campanian age (Upper Cretaceous). They contain reasonable oil quality, varying from 28 to 35 API. Water injection is the predominant main drive mechanism for all fields.

The Ceiba field commenced oil production in November 2000 and as of 1/10/2020 had produced 205.0 MMbbls. The Okume Complex commenced oil production in December 2006 through the Elon field. As of 1/10/2020 the Okume Complex fields have produced a total of 238.4 MMbbls.

The Ceiba field is tied back to the Ceiba FPSO through a system of six subsea manifolds and flowlines where the liquids are processed for export. The Okume Complex fields are developed utilising four fixed jackets (in the Elon field) and two tension leg platforms (to develop remaining fields). All fields are tied back to a central processing facility (CPF) at one of the Elon platforms (Okume C). The processed oil from the CPF is transported via a 25km, 12 inch pipeline to the Ceibo FPSO for export.

Tullow provided TRACS with production history, their decline analysis for producing wells, a summary of recent development activities including actual versus forecasted performance, assumptions and production forecasts for new development activities. They also provided development plans, historical costs and future cost assumptions, fiscal terms and statements regarding estimated Cessation of Production.

TRACS performed an independent review of the Okume Complex and Ceiba field through a mixture of verifying Tullow assumptions and forecasts, adapting assumptions where felt necessary, and performing original technical and commercial analysis where felt justified.

Technical production profiles associated with reserves are truncated at the earliest of Cessation of Production (COP) for technical/commercial reasons or negative pre-tax cashflow in the Economic Limit Test (ELT).

Annual production, cost and oil price forecasts were used in an annual increment economic spreadsheet model at a field level to calculate annual pre-tax cash flows. Calculations were based on the terms of the "PSC EG 2017 Amendment 3_After Tax Resolution.pdf" for Profit Oil share and Income Tax and the "Amendment 1 of Production Sharing Contract" for Royalty and Cost Oil cap. The economic spreadsheet model supplied by Tullow was reviewed by TRACS.

The Reserves and Resource estimates follow the June 2018 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting.

The licence expiry date for Ceiba has been advised by Tullow to be end 2029 and for the Okume Complex to be July 2034. Consequently any reserves quoted are recovered within the licence periods.

All oil volumes quoted are wellhead volumes and it is assumed that there is no oil shrinkage from wellhead to sales volumes. There are no gas reserves or resources. All gas produced is either assumed to be used for fuel or flare.

Decline analysis for producing wells was from monthly average rates. This in part accounts for operating efficiency but does not fully capture the planned and unplanned outages. Based on historical operating efficiency a 95% factor was applied to the final forecasts.

All reserves volumes are quoted from a reference date of 1/10/2020.

Reserves

The Tullow reserves for the Ceiba field and Okume Complex are based on three main components:

- Developed (on production) reserves utilising the current wells
- Approved for Development reserves (AD) predominately associated with identified workovers in the Ceiba and Okume Complex fields
- Justified for Development reserves (JD) which include infill wells in the Elon and Oveng fields.

Note that no Justified for Development (JD) activities were identified for the Ceiba field.

For developed producing reserves Decline Curve Analysis (DCA) was the primary method of estimation. TRACS performed mainly well level DCA and verified results using field level DCA.

For AD and JD activities Tullow's forecasts/estimates and supporting data provided were reviewed and modified as required. For Approved for Development (AD) activities, this required evidence of firm plans in the near term, such as the operator's workover schedule, or AFE's.

Individual forecasts were simply summed for the Ceiba field and Okume Complex fields as there are no facility constraints on production.

STOIIP ranges assessed by TRACS were used to review total recovery and recovery factors in order to identify under or overestimation of resources.

The remaining economic reserves as at 1/10/2020 for Equatorial Guinea as estimated by TRACS are presented in the table below.

Oil Reserves by Category	Gross (MMbbls)			Tullow Net Entitlement(MMbbls)			Tullow WI (MMbls)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed Producing (DP)	32.7	61.5	95.1	3.9	7.3	11.1	4.7	8.8	13.6
Approved for Development (AD)	6.8	14.5	23.5	0.8	1.6	2.5	1.0	2.1	3.3
Justified for Development (JD)	6.3	20.9	36.1	0.8	2.4	3.8	0.9	3.0	5.1
Total All Reserves Categories	**45.7**	**96.8**	**154.7**	**5.5**	**11.2**	**17.4**	**6.5**	**13.8**	**22.1**

Equatorial Guinea Reserves summary

The nominal post tax Net Present Value at discount rates of 10% (NPV10), 8% and 12% from a point forward date of 1 October 2020 was determined independently for the 1P, 2P and 3P Reserves cases for Ceiba and Okume Complex.

Wood Mackenzie's Q3 2020 Brent oil price oil price assumptions were used for the economic evaluation.

	2020	2021	2022	2023	2024	2025
Nominal $/bbl Brent*	40.0	43.0	46.0	50.0	54.1	55.2
Real 2020 $/bbl Brent	40.0	42.2	44.2	47.1	50.0	50.0

* inflated at 2% per annum from 2024.

A crude quality differential of plus $0.75/bbl (nominal) relative to Brent in 2020, plus $0.15/bbl in 2021 and minus $1.0/bbl thereafter for both Okume and Ceiba (the Ceiba Blend) was advised by Tullow.

The NPV of Ceiba 1P, 2P and 3P total reserves are calculated assuming the Okume 2P total Reserves case. The remaining Tullow WI NPV for Ceiba total Reserves at the base case and sensitivity cases to the COP date is estimated to be:

	Ceiba Tullow WI NPV ($MM nom)								
	1P			2P			3P		
Oil Price ($/bl)	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**
NPV 10%	**-11.7**	**1.9**	**-26.3**	**11.4**	**29.0**	**-4.9**	**33.5**	**56.0**	**12.6**
NPV 8%	-17.9	-4.0	-32.2	7.1	25.3	-10.0	30.8	54.3	8.9
NPV 12%	-6.8	6.2	-21.4	14.6	31.4	-1.0	35.2	56.6	15.3

Ceiba Reserves NPV summary

The NPV of Okume 1P,2P,3P total reserves is calculated assuming the Ceiba 2P total reserves case. The remaining Tullow WI NPV for Okume total Reserves at the base case and sensitivity cases to the COP date is estimated to be:

	Okume Complex Tullow WI NPV ($MM nom)								
	1P			2P			3P		
Oil Price ($/bl)	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**
NPV 10%	**0.4**	**19.4**	**-18.8**	**80.0**	**120.4**	**42.4**	**166.7**	**222.4**	**110.9**
NPV 8%	-2.8	16.4	-22.1	80.8	123.7	41.0	176.4	236.7	115.9
NPV 12%	3.1	21.7	-15.9	78.7	116.8	43.1	157.6	209.2	105.8

Okume Complex Reserves NPV summary

Contingent Resources

The Tullow Contingent Resources for Equatorial Guinea are based on the following main components:

- Development pending (CR-DP) activities which include workovers in the Ceiba field and Okume Complex fields
- Development Unclarified (CR-DU) which includes a water injector and a sidetrack in the Ceiba field and infill opportunities for Elon, Oveng and Ebano in the Okume Complex.
- Remaining opportunities which are categorised as Development not Viable (CR-DnV)

For the CR-DP and CR-DU activities production forecasts and resources provided by Tullow were reviewed and modified where considered appropriate.

Post licence expiry CR estimates were estimated using the technical forecasts for reserves and extended to 2050. These are classified as CR-DnV. Further infill potential in the Ceiba and Elon fields is identified and also captured as CR-DnV.

The resulting unrisked Equatorial Guinea Contingent Resources as estimated by TRACS are presented in the table below. These are presented as gross and Tullow working interest estimates.

CR Classification (Oil)	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	4.7	15.4	28.4	0.6	2.2	4.1
Development Unclarified	16.0	40.3	67.7	2.3	5.8	9.6
Development not viable	37.8	123.4	286.9	5.4	17.6	40.9
Total All CR Categories	**58.6**	**179.1**	**382.9**	**8.4**	**25.6**	**54.6**

Equatorial Guinea Contingent Resource summary- Unrisked

A Chance of Commerciality (CoC) has been assessed for all Contingent Resources. The CoC is widely used to assess risked resources and value of oil and gas contingent projects. In SPE PRMS it is defined as "the estimated probability that a project will achieve commercial maturity to be developed. For CR it is equal to the chance of development". In the London Stock Exchange guidelines for oil and gas companies it is defined as "the estimated chance or probability that the (CR) volumes will be commercially extracted".

The CoCs have been applied to the unrisked CR estimates to generate the risked CR as shown in the table below.

Contingent Resources	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Oil (MMbbls)	**21.0**	**62.6**	**126.9**	**3.0**	**9.0**	**18.1**

Equatorial Guinea Contingent Resource summary - Risked

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1 Introduction

TRACS was commissioned by Tullow Oil to complete a Competent Person's Report (CPR) for the Equatorial Guinea assets in the Tullow Portfolio in accordance with Reserves and Resource definitions presented in the SPE's Petroleum Resources Management System (Appendix C).

1.1 Overview

The Equatorial Guinea fields are located offshore Equatorial Guinea in northeastern Block G on the edge of the present day continental shelf in water depths ranging from 50-850 metres (Figure 1-1).

Figure 1-1 Location map

The fields reviewed as part of this CPR are listed in the Table 1-1:

Licence	Field
	Elon
	Okume
Okume Complex	Oveng
	Akom North
	Ebano
Ceiba	Ceiba

Table 1-1 Summary of assets

Ceiba and Okume Complex licences are operated under a Production Sharing Contract (PSC). Trident is the Operator of both licences; in addition to Tullow, other partners include Kosmos Energy and the State. Tullow have an exploration and development working interest of 15% and a revenue working interest of 14.25%.

The main reservoir intervals of the Ceiba field and Okume Complex fields consist of stacked deepwater turbidite channel and overbank deposit reservoirs of Campanian age (Upper Cretaceous). They contain reasonable oil quality, varying from 28 to 35 API. Water injection is the predominant main drive mechanism for all fields.

The Ceiba field commenced oil production in November 2000 and as of 1/10/2020 had produced 205.0 MMbbls. The Okume Complex commenced oil production in December 2006 through the Elon field. As of 1/10/2020 the Okume Complex fields have produced a total of 238.4 MMbbls.

The Ceiba field is tied back to the Ceiba FPSO through a system of six subsea manifolds and flowlines where the liquids are processed for export. The Okume Complex fields are developed utilising four fixed jackets (in the Elon field) and two tension leg platforms (to develop remaining fields). All fields are tied back to a central processing facility (CPF) at one of the Elon platforms (Okume C). The processed oil from the CPF is transported via a 25km, 12 inch pipeline to the Ceibo FPSO for export.

2 Summary of Reserves and Contingent Resources

2.1 Totalled for Equatorial Guinea

2.1.1 Reserves

The total remaining Gross, net entitlement and working interest reserves for Equatorial Guinea at 1/10/2020 are estimated to be:

Oil Reserves by Category	Gross (MMbbls)			Tullow Net Entitlement(MMbbls)			Tullow WI (MMbls)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed Producing (DP)	32.7	61.5	95.1	3.9	7.3	11.1	4.7	8.8	13.6
Approved for Development (AD)	6.8	14.5	23.5	0.8	1.6	2.5	1.0	2.1	3.3
Justified for Development (JD)	6.3	20.9	36.1	0.8	2.4	3.8	0.9	3.0	5.1
Total All Reserves Categories	**45.7**	**96.8**	**154.7**	**5.5**	**11.2**	**17.4**	**6.5**	**13.8**	**22.1**

Table 2-1 Equatorial Guinea Total Reserves summary

2.1.2 Contingent Resources

The total unrisked Contingent Resources for Equatorial Guinea are presented in Table 2-2.

CR Classification (Oil)	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	4.7	15.4	28.4	0.6	2.2	4.1
Development Unclarified	16.0	40.3	67.7	2.3	5.8	9.6
Development not viable	37.8	123.4	286.9	5.4	17.6	40.9
Total All CR Categories	**58.6**	**179.1**	**382.9**	**8.4**	**25.6**	**54.6**

Table 2-2 Equatorial Guinea Contingent Resource summary

2.2 Totalled by Asset

2.2.1 Reserves

A breakdown of total Reserves by asset at 1/10/2020 is given for Ceiba in Table 2-3 and for Okume complex in Table 2-4.

Ceiba

Oil Reserves by Category	Gross (MMbbls)			Tullow Net Entitlement(MMbbls)			Tullow WI (MMbls)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed Producing (DP)	13.1	20.8	27.8	1.6	2.5	3.2	1.9	3.0	4.0
Approved for Development (AD)	2.9	5.3	8.5	0.3	0.6	0.9	0.4	0.8	1.2
Justified for Development (JD)	0.5	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0
Total All Reserves Categories	**16.5**	**26.2**	**36.3**	**2.0**	**3.1**	**4.1**	**2.4**	**3.7**	**5.2**

Table 2-3 Ceiba Reserves– Oil

Ceiba 1P JD reserves result because Okume JD reserves extend the COP of the combined development from 2028 in the DP+AD case to 2029 in the DP+AD+JD case.

Okume Complex

Oil Reserves by Category	Gross (MMbbls)			Tullow Net Entitlement (MMbbls)			Tullow WI (MMbls)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed Producing (DP)	19.6	40.7	67.4	2.3	4.8	7.8	2.8	5.8	9.6
Approved for Development (AD)	3.8	9.1	14.9	0.4	1.0	1.6	0.5	1.3	2.1
Justified for Development (JD)	5.7	20.9	36.1	0.7	2.4	3.8	0.8	3.0	5.1
Total All Reserves Categories	**29.2**	**70.7**	**118.4**	**3.5**	**8.1**	**13.3**	**4.2**	**10.1**	**16.9**

Table 2-4 Okume Complex Reserves– Oil

2.2.2 Contingent Resources

A breakdown of total unrisked CR by asset is given for Ceiba in Table 2-5 and for Okume Complex in Table 2-6.

Ceiba

Oil Contingent Resources by Category	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	3.1	11.1	21.6	0.4	1.6	3.1
Development Unclarified	7.2	19.4	35.1	1.0	2.8	5.0
Development not viable	19.6	41.7	67.5	2.8	5.9	9.6
Total All CR Categories	**30.0**	**72.2**	**124.1**	**4.3**	**10.3**	**17.7**

Table 2-5 Ceiba Contingent Resource summary

Okume Complex

Oil Contingent Resources by Category	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	1.6	4.3	6.8	0.2	0.6	1
Development Unclarified	8.8	20.9	32.6	1.3	3	4.6
Development not viable	18.2	81.7	219.4	2.6	11.7	31.3
Total All CR Categories	**28.6**	**106.9**	**258.8**	**4.1**	**15.3**	**36.9**

Table 2-6 Okume Complex Contingent Resource summary

3 General Methodology and Assumptions

3.1 Overview of process

Tullow provided TRACS with production history, their decline analysis for producing wells, a summary of recent development activities including actual versus forecasted performance, assumptions and production forecasts for new development activities, development plans, historical costs and future cost assumptions, fiscal terms and statements regarding estimated Cessation of Production. TRACS performed an independent review of all assets through a mixture of verifying assumptions, adapting assumptions where felt necessary, and performing original technical and commercial analysis.

3.2 Reserves and Contingent Resources reporting

3.2.1 Reserves

Technical production profiles associated with reserves are truncated at the earliest of Cessation of Production (COP) for technical/commercial reasons or negative pre-tax cashflow in the Economic Limit Test (ELT).

The reserves reporting follows the SPE PRMS. The reserves classification and categorisation reported, along with a simple guide as to how they are applied, are shown in Table 3-1. All reserves volumes are quoted from a reference date of 1/10/2020.

Reserves Classification		General Example	Categorisation		
			1P	2P	3P
Developed Producing	DP	Existing producing well	▪	▪	▪
Approved for Development	AD	Development Capex approved	▪	▪	▪
Justified for Development	JD	Technically justified but awaiting budget approval	▪	▪	▪

Table 3-1 Reserves reporting classification and categories

The 1P (Proved) category approximates a P90 case. The 2P (Proved plus Probable) category approximates a P50 or reference case. The 3P (Proved plus Probable plus Possible) category approximates a P10 case.

3.2.2 Contingent Resources

The SPE PMRS categorisation for Contingent Resources (CR) has been followed. CR is defined as follows: "quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies."

An overview of the SPE PRMS CR classifications (together with brief descriptions) is shown in Table 3-2.

CR Classification	Description	Categorisation		
		1C	2C	3C
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	▪	▪	▪
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	▪	▪	▪
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	▪	▪	▪
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.	▪	▪	▪

Table 3-2 Contingent Resource reporting classification and categories

The 1C category approximates a P90 case. The 2C category approximates a P50 or reference case. The 3C category approximates a P10 case.

3.3 In-Place Volumes

For this review, TRACS have relied on data provided by Tullow whilst taking TRACS experience in the area of interest into consideration.

The objective was to provide in-place volumetric ranges on formation or field level whilst testing their correspondence with production figures. TRACS evaluation approach at a field level varied dependent on: maturity (e.g., appraisal vs early decline or late life), level of operator-partner data sharing and data availability (e.g., reports vs log data and static model) as well as materiality to Tullow.

Where available, log data were checked and compared with static model inputs in order to establish meaningful probabilistic ranges for STOIIP calculation. Seismic data was not assessed in detail. Therefore, TRACS did not check play fairway or facies trends: structural uncertainty and associated gross rock volumes ranges (lognormal distribution) are usually corresponding to stratigraphic setting and the number and distribution of boreholes with wider ranges used for poorer well control. TRACS ascertained that structural model grids adhere to well tops. Fluid distributions from logs and pressure data (where available) were used to compare contacts with those used in the static model and then applied in the probabilistic evaluation (uniform distribution). Average reservoir properties from logs were captured, volume- or TVT-weighted where appropriate and compared to static model value inputs/outputs. Commonly, petrophysical parameter ranges applied in STOIIP probabilistics encompass both log and model data (beta distribution for N/G, porosity and Sw; normal distribution for FVF). Where individual parameter variations were significant, Tracs invoked arithmetic averages of logs and models for low and high cases.

For Ceiba and Okume assets, three reservoir facies types that flow hydrocarbons have been assigned average petrophysical parameters respective to their sedimentary character. Together with their proportions in the static model, a further sense check was provided. The detailed Elon review exemplifies this approach. In the absence of statistically significant well data, analogue reconnaissance data were consulted and probabilistic ranges adjusted accordingly.

For most fields, TRACS ran probabilistic estimates on individual layers or formations in Monte-Carlo software followed by aggregate probabilistic runs as independent layers.

Where estimates aligned with Tullow’s to within +/-10% Tullow’s view was adopted. STOIIP ranges were used to review total recovery and recovery factors in order to identify under or overestimation of resources.

3.4 Production forecasts and Operating Efficiency

For developed producing reserves Decline Curve Analysis was the primary method of estimation. Tullow provided their DCA by well and by field; TRACS reviewed the Tullow analysis but carried out an independent assessment. Figures were then compared, if there were significant differences TRACS consulted with Tullow and revised estimates where appropriate. TRACS performed both well and field level DCA; generally final forecasts were derived from well level DCA summed to the Field level.

Well by well analysis was performed on decline of oil rates versus time. The decline functions consist of a hyperbolic decline profile with shape exponent (*b*) standardised based on drive mechanism, reflecting typical ranges as summarised in Table 3-3.

Drive mechanism	Exponential shape factor b		
	1P (Low)	2P (mid)	3P (high)
Strong aquifer or waterflood	0.2	0.6	1.0
Depletion drive	0.0	0.2	0.4
Solution gas or weak aquifer drive	0.1	0.3	0.5

Table 3-3 Exponential b- factors by drive mechanism

The remaining parameters to define the decline were the deliverability and decline rate at the reference date 01/10/2020. The decline rates were taken to be consistent with the range of field declines observed during the field history (curve fit over a representative interval). Initial rate is taken as the average monthly rate at the end of the production history if representative, otherwise an appropriate rate is selected based on a review of the production trends towards the end of the history period taking into account any short term operational issues.

Water cut development was also reviewed as a sense check and to gain insight on the potential behaviour of existing production and further development activities.

Decline was from monthly average rates. This in part accounts for operating efficiency but does not fully capture the planned and unplanned outages. Based on historical operating efficiency a 95% factor was applied to the final forecast.

For future development activities Tullow's estimates and supporting data provided were reviewed. For Approved for Development (AD) activities, this required evidence of firm plans in the near term, such as the operator's rig schedule, or AFE's.

Review of workover activities included:

- Confirmation incremental rates matched past performance, and are backed by well modelling calculations by Tullow or the Operator.
- Confirmation that incremental recoveries are reasonable by comparison to similar workovers.
- Review of type curve decline parameters and recovery, to check that suitable parameters had been selected and that the range was representative of possible outcomes.

In-fill well activities were reviewed in much the same way, with a focus on recovery per well based on the in-field historical recoveries adjusted to account for advancing field maturity, i.e. a decrease in recovery with advancing number of wells and with the advance of flood fronts.

Constraints on production streams (oil, liquid, water, gas) and water injection were reviewed at a field and at a facilities/complex level. The ability to lift fluids and flow assurance issues were also taken into account.

There are currently no production system constraints on the Okume Complex fields. Ceiba relies on pressure maintenance, multi-phase booster pumps at drill centre manifolds and flow line gas lift to produce back to processing facilities on an FPSO.

Individual forecasts were simply summed as there are no constraints on production.

3.5 Cessation of Production (COP) dates

The cessation of production date is the earliest of the production license expiry date, facilities design lifetime, end of technical production profile or economic limit.

3.6 Development plans and cost estimates

The life of field cost data provided was reviewed for consistency and reasonableness where and when it has an impact on the economic cut-off date of the asset and where required to test the economic viability of any JD reserves and/or Development Pending contingent resources. If the development scope used for the generation of the production profiles differed from that of the costs provided the costs were adjusted accordingly following consultation with Tullow. If the input to Tullow's economic spreadsheet omitted or contained erroneous costs e.g. compared to the supporting material these were added following consultation with Tullow.

The historic gross Capex and Opex from 2018 to end September 2020 for Ceiba and Okume is summarised below.

Ceiba	**2018**	**2019**	**YTD Sept 2020**
Opex ($MM)	77.8	69.8	30.3
Capex ($MM)	-0.6	26.2	16.9

Okume	**2018**	**2019**	**YTD Sept 2020**
Opex ($MM)	103.6	106.6	76.7
Capex ($MM)	0.8	5.7	17.2

Total Equatorial Guinea	**2018**	**2019**	**YTD Sept 2020**
Opex ($MM)	181.4	176.4	107.0
Capex ($MM)	0.1	32.0	34.1

Table 3-4 Equatorial Guinea historic gross costs summary

3.7 Economic evaluation

Annual production, cost and oil price forecasts were used in an annual increment economic spreadsheet model at a field level to calculate annual pre and post-tax cash flows. Calculations were based on the terms of the "PSC EG 2017 Amendment 3_After Tax Resolution.pdf" for Profit Oil share and Income Tax and the "Amendment 1 of Production Sharing Contract" for Royalty and Cost Oil cap. The economic spreadsheet model supplied by Tullow was reviewed by TRACS.

The cash flows were determined for the 1P, 2P and 3P reserves cases for the DP, DP+AD, DP+AD+JD reserves categories in turn in order to assess the economic limit. The economic limit is defined as the year in which the Contractor cumulative pre-tax cash flow, post Royalty and excluding the final abandonment costs is at its maximum. For Ceiba and Okume the cut-off is determined based on the combined cashflow of the two assets due to their interdependency. The reserves in each category were then determined by difference.

The economics of projects categorised as JD were tested in order to check their inclusion in the respective category. The criteria for inclusion was assumed to be the achievement of:

- a positive post tax NPV10% in the 1P case, and
- a post tax IRR > 15% in the 2P case.

This is based on the incremental economics from a point forward date of 1 October 2020.

No economic evaluation was performed for contingent resources.

The reserves/resources are reported as "Gross Reserves" i.e. the 100% field share, Tullow net entitlement share and Tullow working interest.

3.7.1 Risked volume and value

A Chance of Commerciality (CoC) has been assessed for each CR project evaluated in the CPR . The CoC is widely used to assess risked resources and value of oil and gas contingent projects. In SPE PRMS it is defined as "the estimated probability that a project will achieve commercial maturity to be developed. For CR it is equal to the chance of development". In the London Stock Exchange guidelines for oil and gas companies it is defined as "the estimated chance or probability that the (CR) volumes will be commercially extracted".

The CoC is applied to the unrisked CR volumes to generate risked CR volumes.

3.7.2 Product price deck

Wood Mackenzie's Q3 2020 Brent oil price assumptions were used for the economic evaluation.

	2020	2021	2022	2023	2024	2025
Nominal $/bbl Brent*	40.0	43.0	46.0	50.0	54.1	55.2
Real 2020 $/bbl Brent	40.0	42.2	44.2	47.1	50.0	50.0

* inflated at 2% per annum from 2024.

Sensitivities to the NPV 10%, 8% and 12% are carried out at +/- $10/bbl Real Terms 2020 (RT20).

No gas is exported from Ceiba or Okume.

3.7.3 Price differential

A crude quality differential of plus $0.75/bbl (nominal) relative to Brent in 2020, plus $0.15/bbl in 2021 and minus $1.0/bbl thereafter for both Okume and Ceiba (the Ceiba Blend) was advised by Tullow.

3.7.4 Inflation

An inflation/ escalation rate of 2% per annum is assumed for all nominal costs.

3.7.5 PSC terms

The Royalty paid by the Contractor, quoted as a percentage of the gross sales oil varies by production tranche. At the current rate it is 11%. Royalty is paid in cash, rather than in kind hence the 'Royalty barrels' are included in the entitlement volumes.

Royalty	Upper limit (bbl/d)	
Production Tranche 1	30,000	11%
Production Tranche 2	60,000	12%
Production Tranche 3	80,000	14%
Production Tranche 4	100,000	15%
Production Tranche 5	-	16%

The Contractor's Cost Oil recovery limit is 70% of the Gross revenue after the deduction of Royalty. Cost recovery is made on the basis of depreciated tangible costs and undepreciated intangible costs.

The Contractor's share of profit oil (gross revenue after royalty and cost recovery) per cumulative production tranche is as follows:

Profit Oil	Upper limit (MMbls)	
Production Tranche 1	200	92.3%
Production Tranche 2	350	80.8%
Production Tranche 3	450	69.2%
Production Tranche 4	550	57.7%
Production Tranche 5	-	46.2%

3.7.6 Taxation

Income tax, after deductions is charged at a rate of 35%. The valuation assumes that Tullow's 2019 tax liability was settled as due in 1H 2020 and therefore has no impact on the 1 October 2020 point forward NPV.

3.7.7 License award and working interest

Ceiba licence expiry is end 2029 and Okume Complex July 2034.

Tullow have an exploration and development working interest of 15% and a revenue working interest of 14.25%. The licences are operated by Trident.

3.7.8 Shrinkage, yield factors and boe equivalents

No crude shrinkage factor is applied between wellhead to sales.

There is no gas sales, hence no NGL yield factors were applied.

3.7.9 Fuel and flare

There is no sales gas, fuel and flare gas usage is not relevant to the reserves and resources.

4 Ceiba

4.1 Field Background

Field Name	Ceiba
Location	Offshore Equitorial Guinea, Rio Muni Basin, 1.4538 N, 9.1852 E
Tullow working interest	Exploration and development working interest of 15% and a revenue working interest of 14.25%
Operator	Trident (Operator since 2017)
Geology	Stacked deepwater turbidite channel and overbank deposit reservoirs of Campanian age (Upper Cretaceous), on-lapping a salt-cored structure. Reservoirs are partially separated by intra-formational sealing shales. Complex internal geometry; impacting sweep and pressure communication.
HCIIP estimate	776 MMbbls (Mid case)
Development type	First oil November 2000. Production from 6 subsea manifolds (well clusters) each with water injection. Liquids are processed and stored on the Ceiba FPSO; flow from clusters is assisted by MP booster pumps and gas lift. Injection water is treated and pumped from FPSO to well clusters. Drive mechanism is a combination of water injection support and depletion.
Number of active production & injection wells	16 producers, 10 water injectors current (total development well count of 41, 26 Producers plus 15 injectors)
Cumulative production to 1/10/2020	205.0 MMbbls
Current recovery factor (based on Mid STOIIP)	26.4%
Plans for further development	Firm plans for additional workovers. Infill well opportunities identified.

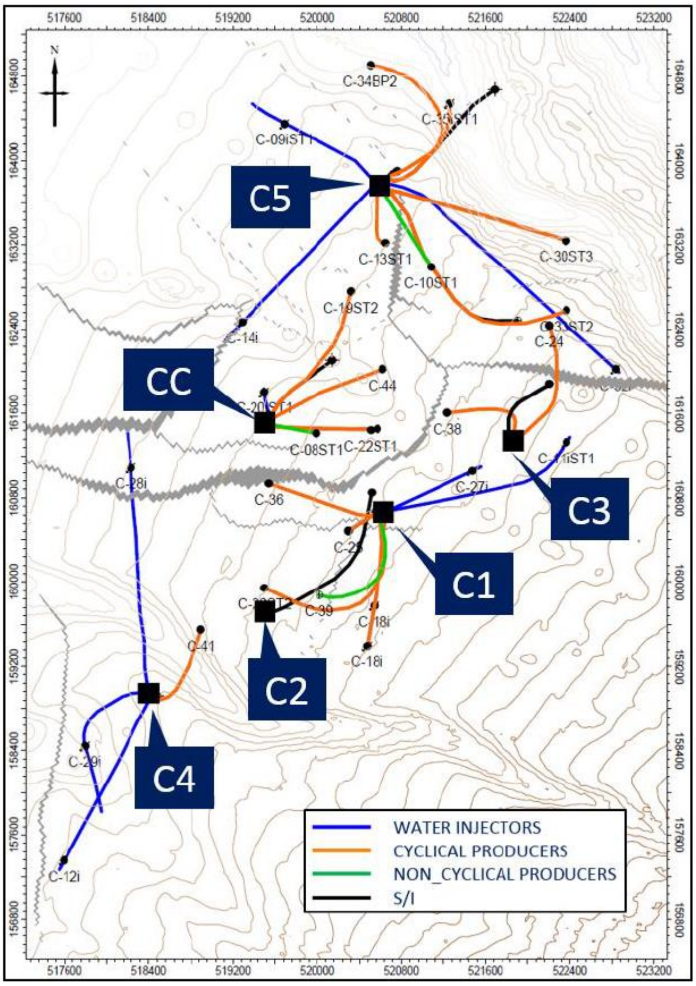


Figure 4-1 Layout of subsea infrastructure

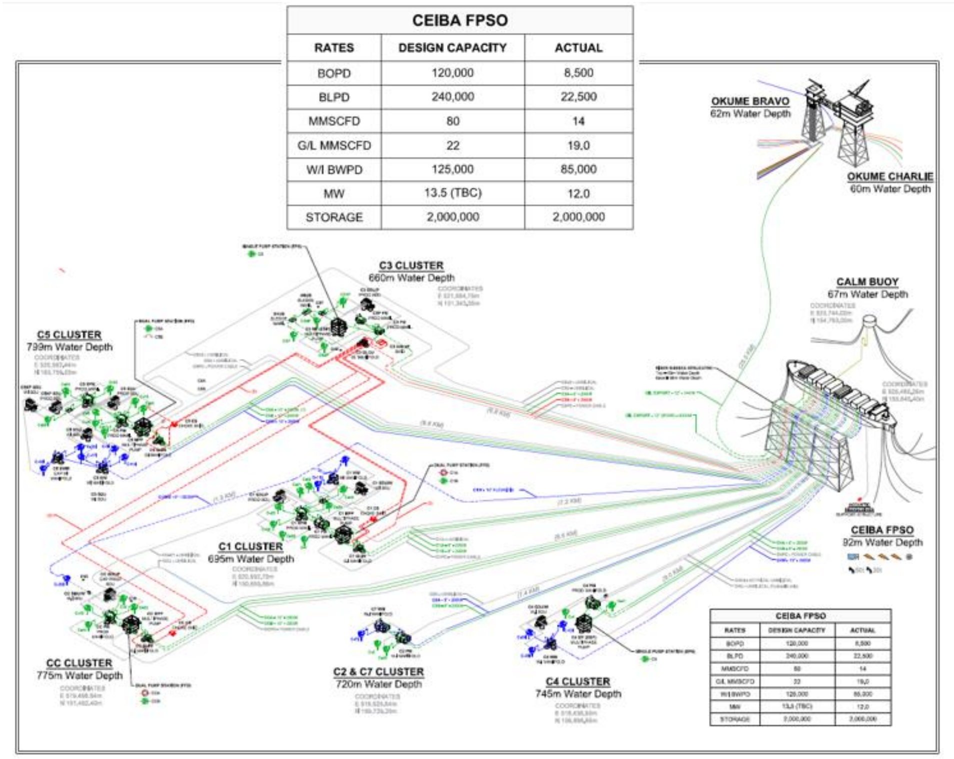


Figure 4-2 Facilities layout and capacities

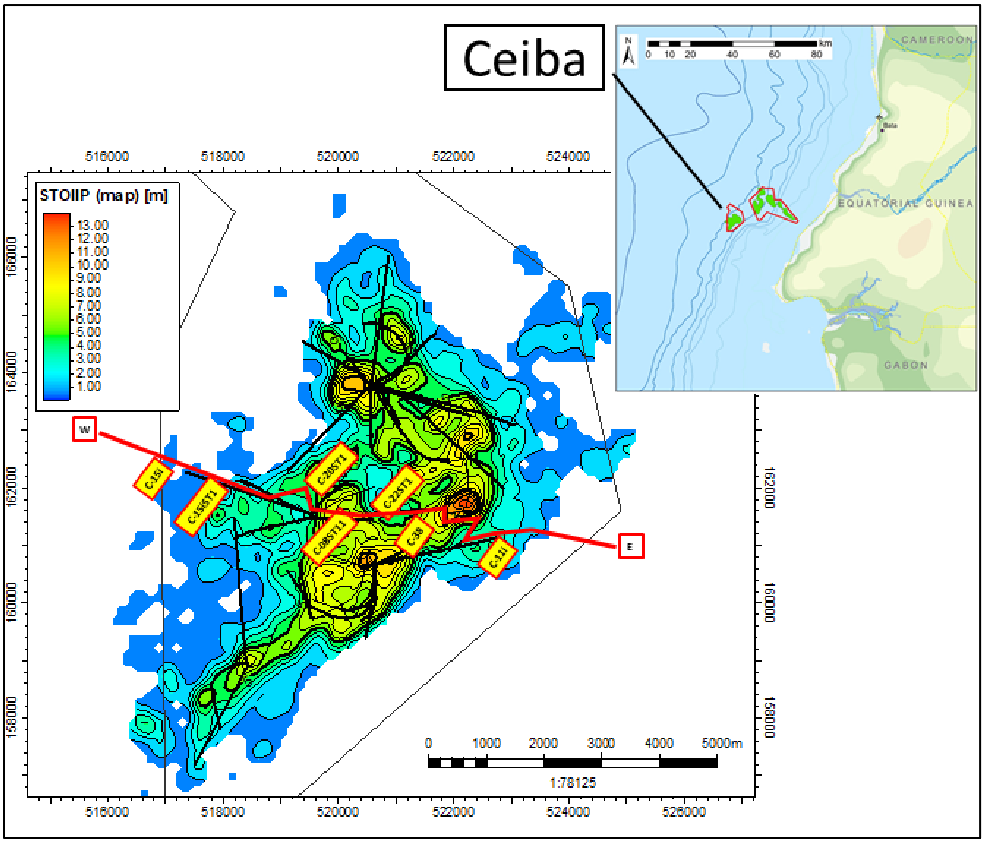


Figure 4-3 Composite STOIIP map base on 2019 static model with location of section shown below

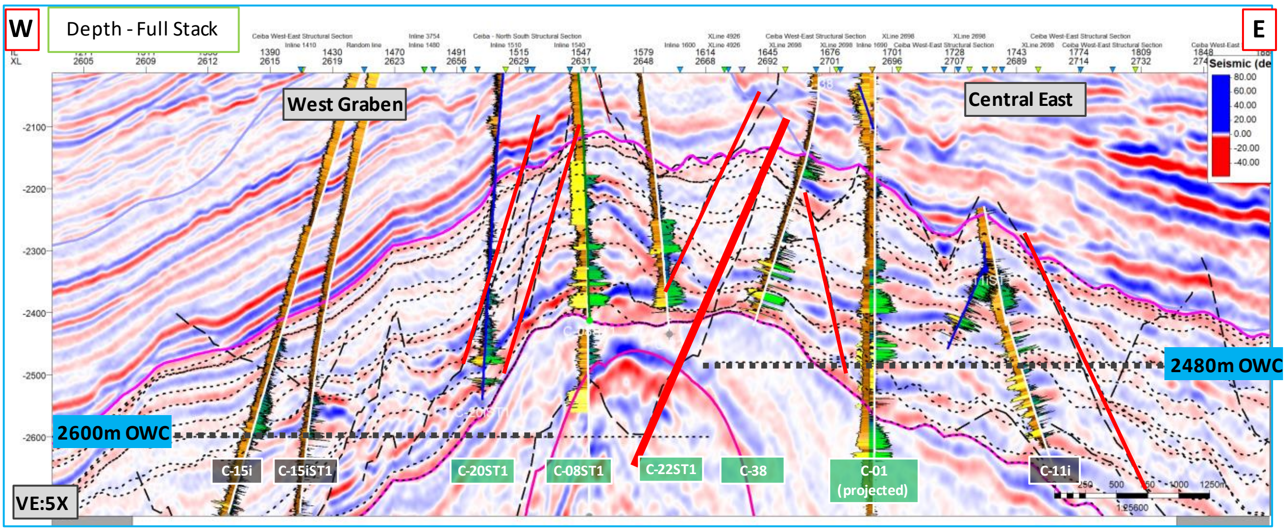


Figure 4-4 Full stack W-E composite seismic section across salt-cored Ceiba structure with onlapping and draping turbidite deposits

4.2 G&G and petrophysical review

Tullow's non-operated assets in Equatorial Guinea are located in Block G in the southern part of the offshore Rio Muni Basin (Figure 4-3). Westward-dipping sedimentary wedges have been deposited in the post-salt Cretaceous and Tertiary. They are bounded in the north and south by major NE–SW-trending faults following the direction of the northern Bata and the southern Ascension fracture zones. The shelf is relatively narrow commonly not exceeding 20 km. The key reservoir units are of Campanian age and represent vertically stacked and laterally migrating sinuous deepwater turbidite channels. Channels entered the area from the southeast. Depositional fairways and trap formation have been influenced by transform margin tectonics and halokinesis by underlying Aptian salt creating mini-basins and submarine ponds. Lateral and downstream channel migration progressively cannibalises older channel deposits resulting in mappable scour boundaries. Some stacked channels are vertically separated by shale units. Reservoir strata onlap, drape and moved around diapiric highs. Further inversion in the Late Senonian enhanced the traps and resulted in tilting, faulting and erosion affecting the reservoir succession. The Ceiba and Okume reservoirs are likely charged from syn-rift source rocks (mostly oil prone) migrating updip and along faults through salt windows. Seal rocks are commonly intraformational encasing shales

For Ceiba and Okume, Tullow have used multiple seismic datasets and rock physics inversions (RPI) provided by the Operator to determine the geobodies which conform to seismically mapped geometries. RPI and well data was then used to populate a static model with petrophysical properties. Trident have defined three reservoir facies types (amalgamated or channel sands, thick beds and thin beds,) and two non-reservoir facies types (tight and shale). These facies are corroborated by core and log data. Reservoir deposits are characterised by thick-bedded massive sands ("amalgamated or channel") associated with the channel axis. These are commonly thicker than 20 cm. Thinner sand layers exceeding 2 cm ("thick thins") relate to channel tops and proximal to medial levee environment whereas thin sands of <2 cm were interpreted as channel abandonment and medial to distal levee facies. Previously, production from wells in areas dominated by "thin thins" have been underestimated and TRACS have suggested that despite of the thin nature of these reservoirs, N/G is still sufficient to allow fluid flow. The reservoir section exhibits permeability heterogeneity, especially perpendicular to the sedimentary supply axis. Preserved sand reservoirs are variable in map outline and are complexly connected both vertically and horizontally. Flow baffles and barriers associated with debris flows, slumps, and mudstones are expected internal to each channel sand body and between bodies.

The Ceiba field is located in 600-800 m of water depth on the slope of the southern Rio Muni Basin (Figure 4-3). The Campanian turbidite channel succession was encountered at 2000–3000 m along a north-south waxing crescent-shaped faulted anticline with a salt core. Turbidity channel fairways were initially deflected along an eastern and northern fairway displaying onlap against the structure. Following basin filling, turbidites draped onto the anticline forming a number of ponded lobes with avulsion, bifurcation and crevasse splays. Some deposits slumped basinward along listric faults initiating near the crest of the structure. Further uplift may have occurred post deposition. Reservoir deposits decrease in age northward suggesting a gradational shift of sedimentation towards the northern areas in response to available accommodation space. Eight reservoir zones have been distinguished across four major structural and stratigraphic segments with weak communication across the areas. Two OWCs have been encountered and assigned to eastern area at 2480 m and a further contact at 2600 m TVDSS on the western side of the structural crescent (Figure 4-4).

For TRACS STOIIP estimates, GRV variations have not been applied. Contacts were confirmed by well data. TRACS have not conducted a detailed petrophysical evaluation for this review of Ceiba. However, results from the detailed analysis of the neighbouring Elon field in analogue reservoirs have been used to determine appropriate N/G, porosity and oil saturation levels pertaining to each facies class. In recent model revisions, N/G associated with thin sand layers (<2 cm) as proven by producing wells has been added and this is also acknowledge in this review. Porosity and saturation are not considered key uncertainties at Ceiba and thus probabilistic variations have been kept small. TRACS distribution confirms Tullow's STOIIP estimate for Ceiba within 5% when comparing the respective P50/base case. Therefore TRACS have adopted Tullow's STOIIP estimate.

4.3 Reserves

4.3.1 Introduction

Since taking over the Operatorship in 2017 Trident has been focused on increasing production through a series of well and subsea interventions and better reservoir management. Voidage replacement and availability have improved, resulting in the stabilisation of watercut trends and the flattening of oil decline trends (Figure 4-5).

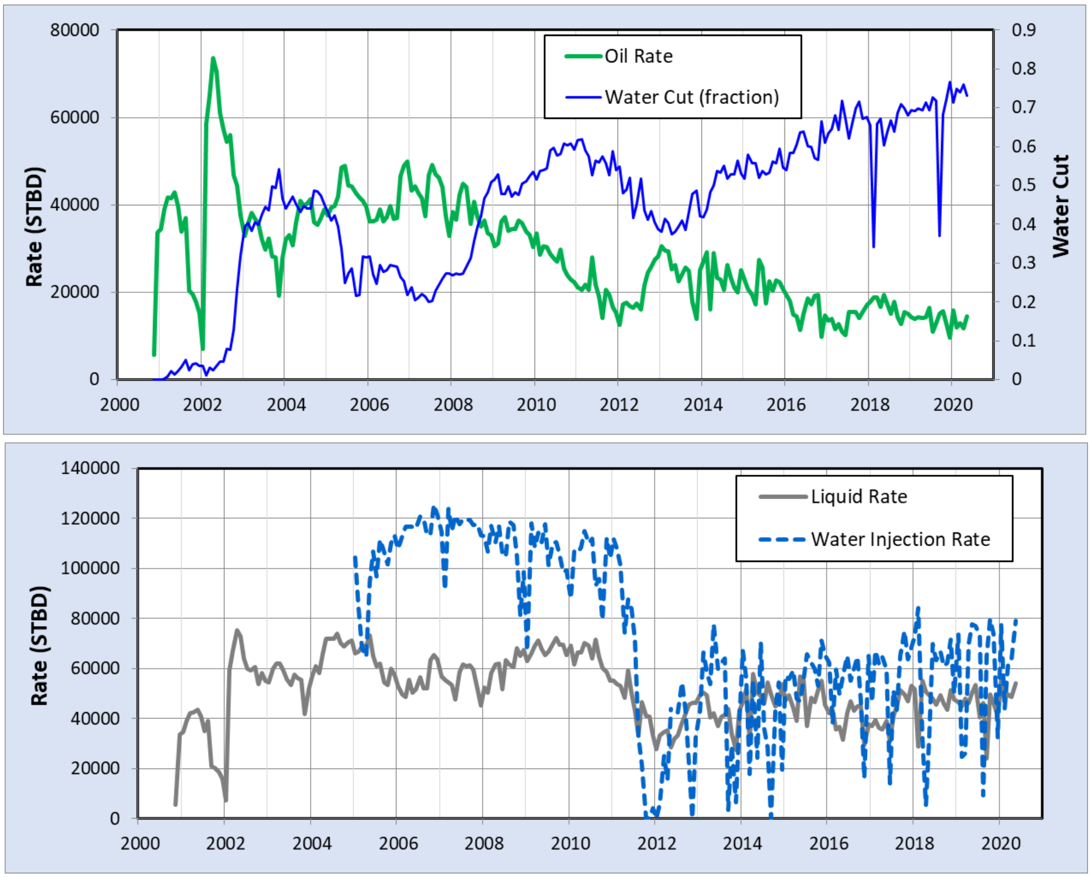


Figure 4-5 Ceiba Field Production trends

4.3.2 Reserves estimation and production forecasts

4.3.2.1 Developed Producing (DP)

To estimate the reserves associated with the current development the Ceiba production performance was reviewed. The operator is very active in improving operation efficiency with the best field management practices. Tullow has provided monthly well by well production data up to end of March-2019 and field level monthly production data to the end of Sept-2020. The production forecasts of Ceiba DP estimates have been generated using decline curve analysis (DCA) performed at a field level.

The Ceiba field production is driven by water injection from 10 active water injections. Therefore, b-factors of hyperbolic decline for the water injection were selected for the DP reserve forecast based on the historical production data (See Section 2.5).

- 1P: b=0.2
- 2P: b=0.6
- 3P: b=1.0

The wide range of DP reserves have been created by the selection of the decline starting points initial forecast oil rate (Figure 4-6), to capture the uncertainty of the reserves forecast.

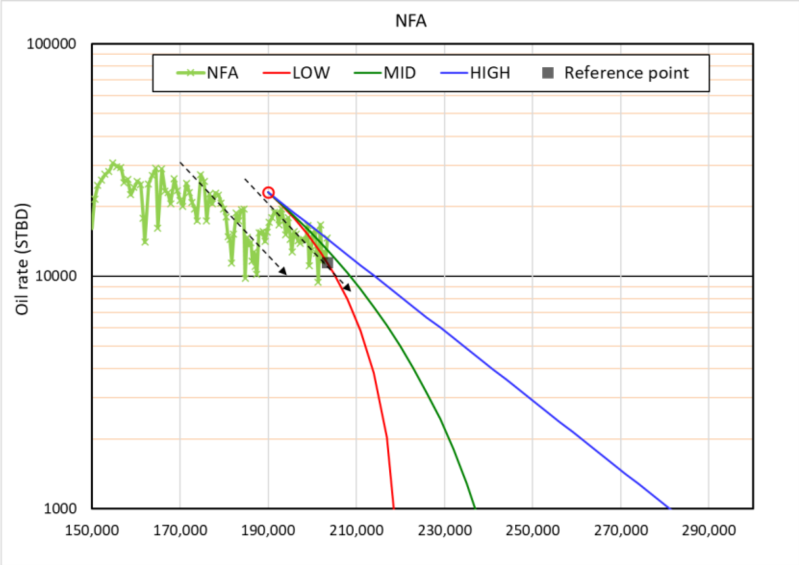


Figure 4-6 DCA for the Ceiba DP reserve forecast

The DP technical forecast at license expiry are 13.6, 20.8 and 27.8 MMbbls for 1P, 2P and 3P, respectively. The Ceiba field production history and the field based DCA for DP reserves forecast are illustrated in Figure 4-7.

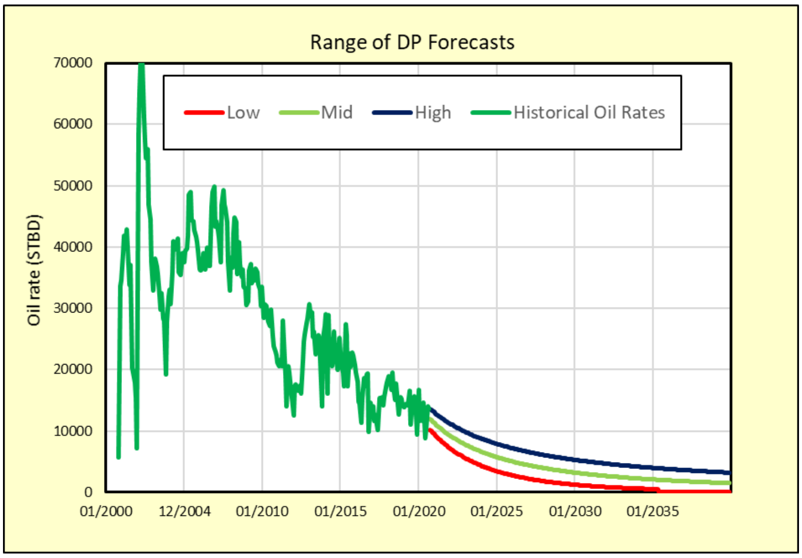


Figure 4-7 Production history, field-based DCA for Ceiba DP reserves

4.3.2.2 Incremental Projects

The Operator has firm plans for three activities which have been classified as AD reserves. These are:

- Reconnection of well C-03 reconnection in order to resume oil production; the well has been shut-in since June 2006. This includes the installation of a rigid jumper from C-03 to the Cluster 3. This is planned for September 2020
- Upgrade of the gas lift distribution unit which is ongoing and estimated to be completed June 2021
- Stimulation campaign in 2021 which targets the C034, C-36 and C-44 wells.

Note that no JD activities have been identified for Ceiba.

DCA was used to generate forecasts from historical decline trends for C-03 reconnection AD reserves. The 2P incremental reserves for upgrade of the gas lift to ESP and 2021 stimulation campaign proposed by Tullow were reviewed and considered to be reasonable when compared to the historical performances. The AD technical forecast at license expiry are 3.0, 5.4 and 8.5 MMbbls for 1P, 2P and 3P, respectively. The range is wider than that proposed by Tullow; and accounts for some uncertainty with respect to pressure support.

4.3.2.3 Forecast constraints and operating efficiency

An uptime factor of 0.95 was applied to all forecasts and forecasts were summed as described in Section 0. The production history and forecast for Ceiba Reserves is shown Figure 4-8.

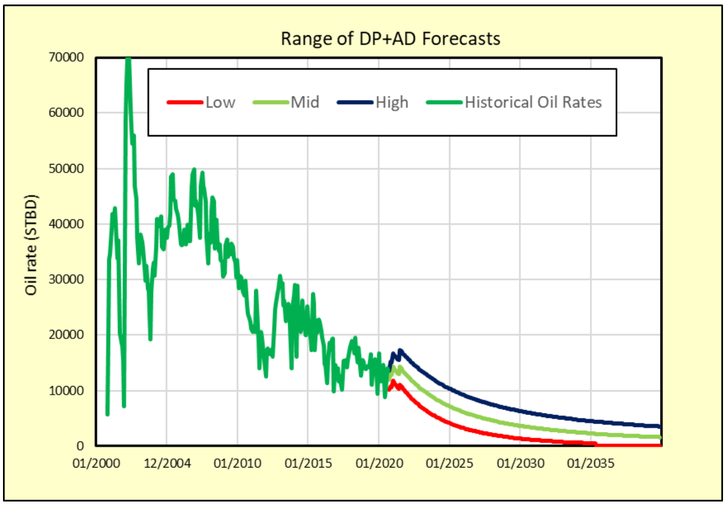


Figure 4-8 Production history and forecast for Ceiba Field Reserves.

4.3.3 Cessation of production date

The cessation of production date is the earliest of the production license expiry date, facilities design lifetime or economic limit. Ceiba License expiry is end 2029. Ceiba first oil was achieved in 2000. With sufficient preventative maintenance it is likely that the facilities would be able to operate a few years beyond the usual 25 year facilities design lifetime. Okume requires the Ceiba FPSO to remain on station to provide oil storage and export even if the Ceiba topsides facilities are mothballed after Ceiba COP.

4.3.4 Development plans and cost estimates

The Ceiba subsea centre tiebacks are processed on the Ceiba FPSO. As a consequence there is an element of shared Opex (and in past years shared Capex) with Okume.

Tullow provided a spreadsheet giving an overview of the annual development well Drillex, facilities Capex and Operational costs for the activities in each reserves category. All costs are quoted gross RT20.

The Operator’s 2020 Budget data (reforecast March 2020) was provided along with supporting data for the basis of the shareable (common) Opex. The 2019 and 2020 TCM/OCM slides which included technical and cost detail of the Operator’s planned activities were also provided.

The Operator’s budget carries a Capex of $27.9MM in 2020, including:

- New 8” production flowline, $6.2MM (DP)
- Offloading hoses replacement, $6.0MM (DP)
- Gas lift distribution unit and gas lift network upgrades, $15.7MM (AD).

Approximately 10kbbl/d of current production depends on gas lift. The subsea upgrade to distribution unit and network aims to improve integrity by replacing leaking units/flexible and add lift gas to the CCA flowline, C-41 and C-44 wells.

Tullow provided the November 2020 monthly finance data showing the Capex and Opex allocation to end November and the forecast for December 2020. The Ceiba allocated Capex spend to end September 2020 was $16.9MM and the forecast for Q4 2020 is $5.0MM.

Post 2020, $3MM (DP) Capex is carried in 2021 for M50 water injection system improvements aimed at improving the water injection system uptime. No further Capital expenditure is planned for incremental reserves.

The Operator's 2020 budget quotes the 2020 Routine Opex plus non-capital projects cost (Opex) as $65.7MM, including Ceiba's share of the shareable Opex.

The Ceiba 2020 dedicated Opex ($54.5MM) i.e. excluding forecast Opex share, is split as follows:

- Maintenance, $23.2MM (DP)
- Direct Opex, $24.9MM (DP)
- Above field, $3.0MM (DP)
- C03 hookup, $3.4MM (AD)

In the November finance data the Ceiba allocated Opex spend to end September 2020 was $30.3MM and the forecast for Q4 2020 is $12.2MM.

The annual dedicated (DP) Opex forecast from 2021 onwards is unchanged from the 2019 Reserves Audit at $39.3MM real terms flat (maintenance, $14.3MM; Direct Opex, $23.1MM and above field, $1.9MM).

In addition the following reserves workover/ intervention costs are forecast post 2020:

- Stimulation campaign, $12.3MM in 2021 (AD)

No additional Opex is added for the operation of Ceiba in 'lighthouse' mode post it's COP i.e. for the continued storage and export of Okume oil. It is assumed that these costs are included in the shared Opex.

The Operator's March reforecast of the annual Shareable Opex excluding allocated corporate overhead / G&A is $40.0MM (DP). This is assumed real terms flat and is allocated based on the ratio of oil production between Okume and Ceiba. In the November finance data the forecast Shareable Opex for Q4 2020 is $10.8MM.

TRACS consider the forecast Capex and Opex to be consistent and reasonable.

Tullow advise that there are no tariffs applicable to Ceiba.

Abandonment provision for cost recovery and tax deduction purposes is included in the economic model. The model indicates that the provision account balance is such that no further payments are required. The Operator's 2019 estimate of the Ceiba decommissioning cost is $395MM RT19. Whilst the license expiry date and hence latest COP date of Ceiba is end 2029, the Ceiba abandonment cost is deferred until the calculated cut-off date of the combined fields given that Ceiba and Okume are likely to be decommissioned together.

There are no incremental abandonment costs for the AD projects.

4.3.5 Reserves summary and valuation

The economic cut-off is determined by the combined Ceiba Okume cashflow considering both fields at the same reserves category i.e. DP & DP, DP+AD & DP+AD etc. The economic cut-off of Ceiba at 1P/2P/3P assumes Okume at its 2P case.

The COP dates used for the estimation of remaining reserves is as follows:

Reserves Category	1P	2P	3P
DP	2028	2029	2029
DP+AD	2028	2029	2029

Table 4-1 COP dates by Reserves category for Ceiba

The remaining economic reserves as at 1/10/2020 are estimated to be:

Oil Reserves by Category	Gross (MMbbls)			Tullow Net Entitlement(MMbbls)			Tullow WI (MMbls)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed Producing (DP)	13.1	20.8	27.8	1.6	2.5	3.2	1.9	3.0	4.0
Approved for Development (AD)	2.9	5.3	8.5	0.3	0.6	0.9	0.4	0.8	1.2
Justified for Development (JD)	0.5	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0
Total All Reserves Categories	**16.5**	**26.2**	**36.3**	**2.0**	**3.1**	**4.1**	**2.4**	**3.7**	**5.2**

Table 4-2 Ceiba - Reserves summary

Ceiba 1P JD reserves result because Okume JD reserves extend the COP of the combined development from 2028 in the DP+AD case to 2029 in the DP+AD+JD case.

The NPV of Ceiba 1P, 2P and 3P total reserves are calculated assuming the Okume 2P total Reserves case. The remaining Tullow WI NPV for Ceiba total Reserves at the base case and sensitivity cases to the COP date is estimated to be:

	Tullow WI NPV ($MM nom)								
	1P			2P			3P		
Oil Price ($/bl)	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**
NPV 10%	**-11.7**	**1.9**	**-26.3**	**11.4**	**29.0**	**-4.9**	**33.5**	**56.0**	**12.6**
NPV 8%	-17.9	-4.0	-32.2	7.1	25.3	-10.0	30.8	54.3	8.9
NPV 12%	-6.8	6.2	-21.4	14.6	31.4	-1.0	35.2	56.6	15.3

Table 4-3 Ceiba Reserves NPV summary

4.4 Contingent Resources

4.4.1 Overview of activities

Further interventions have been identified and are being matured, these form the basis for Contingent Resources Development Pending; these are in part dependent on the success of AD activities.

Subsurface studies are ongoing and a portfolio of development activities is under review, these include infill well activities identified by the previous Operator. Those activities currently deemed more likely to go ahead are classified as Development Unclarified, the remaining opportunities have been categorised as Development not Viable (DnV). Note that Ceiba DnV volumes have been identified in two areas:

- possible additional infill wells where no plans or ongoing studies have been sighted but where there could be economic potential
- volumes beyond licence extension which are currently taken to be commercially not viable.

4.4.2 Estimation of Contingent Resources

Tullow's/Operator estimates were reviewed and if deemed reasonable were adopted. Production forecasts were generated for Contingent Resources Development Pending and Development Unclarified. No production forecasts were generated for other categories of Contingent Resources.

4.4.2.1 Contingent Resources Development Pending (CR-DP)

Four workovers tentatively planned for 2022 are being matured, these include:

- C-33ST2 reactivation is to resume oil production as it shut-in since Feb 2016 due to hydrates at the Cluster-5.
- C-31 reconnection and conversion to water injection supporting an area of the field with low pressure support; wells C-43 and C-25R. The well has been shut-in since May 2012.
- C17i reactivation to resume water injection support to well C-10. Shut-in since Oct 2013; this may include perforation of additional sands.
- Reinstatement of production from Well C-21 shut-in due to integrity issues in Feb 2014.

The Tullow/Operator range of CR for these incremental projects were reviewed and modified where considered appropriate. The TRACS estimates are presented in Table 4-4. The recoverable volumes are estimated out to the end of 2050.

Project Area	CR Category	Oil Recovery (MMstb)		
		1C	2C	3C
C-21 WO	**Development Pending**	0.9	2.6	4.5
C-33 ST2 WO		1.0	3.7	7.0
C-31 WO		0.5	2.0	4.3
C17i WO		0.7	2.7	5.7
Total		**3.1**	**11.1**	**21.6**

Table 4-4 Range of CR for Ceiba CR-DP projects

4.4.2.1.1 Production forecasts

A production forecast was generated for the mid (2C) case only. Decline parameters for each of the workovers supplied by Tullow/Operator were deemed to be reasonable and used together with the estimated recoverable volumes to generate the forecast. A facilities uptime factor of 95% was applied.

The production forecast for the 2C CR-DP case is shown Figure 4-9.

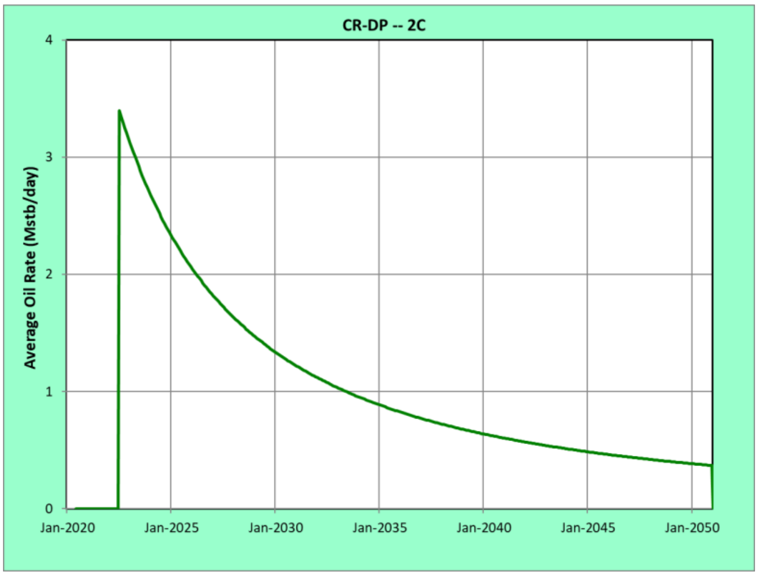


Figure 4-9 Production forecast for CR-DP, Ceiba Field.

4.4.2.2 Contingent Resources Development Unclarified (CR-DU)

Remaining opportunities recognised by the Operator (and Tullow) and planned for post 2022 were reviewed. Three activities were identified that were categorised as Development Unclarified. These are assumed to be planned for mid-2023. The activities are:

- Additional perforations in the C-30ST3 well (A0 sand) and in the C32 water injector well (in the A0, A2 and B sands)
- New water injector to support C-08
- Sidetrack of the C-43 well targeting the remaining recovery associated with C01 well

The Tullow/Operator range of CR for these incremental projects were reviewed and updated where considered appropriate. The TRACS estimates are presented in Table 4-4. The recoverable volumes are estimated out to the end of 2050.

Project Area	CR Category	Oil Recovery (MMstb)		
		1C	2C	3C
C-30ST3 perfs	**Development Unclarified**	3.1	8.1	14.5
Water injector to support C08		2.1	6.5	12.4
C-43St		2.1	4.8	8.2
Total		**7.2**	**19.4**	**35.1**

Table 4-5 Range of CR for Ceiba DUCR projects

4.4.2.2.1 Production forecasts

Decline parameters for each of the CR-DU activities provided by Tullow was deemed to be reasonable and used together with the estimated recoverable volumes to generate the mid case forecast. The production forecast for CR-DU is shown Figure 4-10.

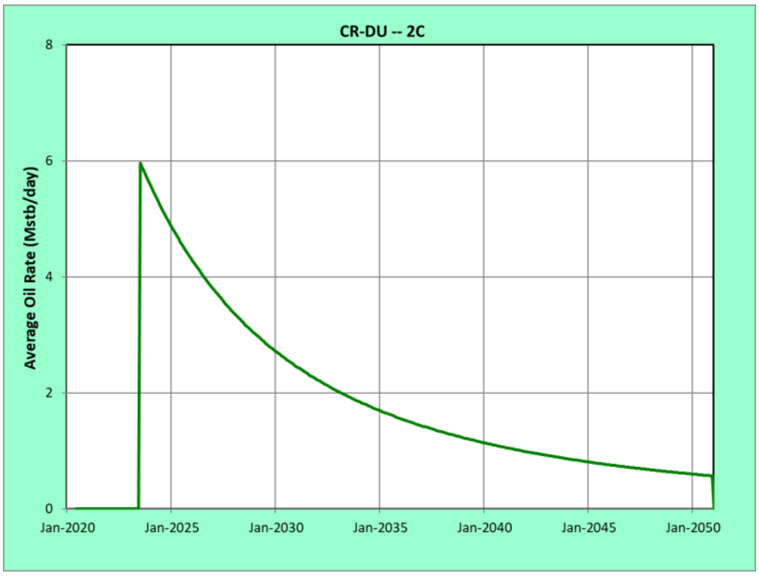


Figure 4-10 Production forecast for CR-DU, Ceiba Field.

4.4.2.3 Contingent Resources Development not Viable (CR-DnV)

Additional recovery potential has been identified in two main areas:

- Additional infill campaigns: the Operator continues to look for possible infill opportunities and plans to undertake further studies to firm up these opportunities
- Recoverable volumes beyond Reserves COP: this captures volumes beyond the reserves COP dates (see Table 4-1) until end 2050. The volumes are estimated using the profiles created for reserves (see Section 4.3.2).

These CR volumes are classified as Development not Viable as there are no current plans for development (infill wells) or are currently shown to be commercially not viable (extension volumes).

Recoverable volumes for a number of notional infill well targets have been provided by the Operator/Tullow and have been accepted by TRACS as being reasonable to reflect the potential for additional infill. Based on all reserves and CR categories the total range of ultimate recovery for Ceiba represent a range of recovery factors of 25%-42%-50% for low, mid and high cases, respectively.

The TRACS estimates are presented in Table 4-4. The recoverable volumes are estimated out to 2050.

Project Area	CR Category	Oil Recovery (MMstb)		
		1C	2C	3C
Additional Infill wells	Development not Viable	11.9	17.4	22.0
Life Extension		7.7	24.3	45.5
Total		**19.6**	**41.7**	**67.5**

Table 4-6 Range of CR for Ceiba DnV CR projects

4.4.2.4 Chance of Commerciality

The results presented in Sections 4.4.2.1 to 4.4.2.3 are unrisked results. In this section a Chance of Commerciality (CoC) is estimated for the CR Resources. The relevant CoCs are then applied to the unrisked numbers to generate risked Resources (see Section 4.4.3).

The projects associated with Development Pending CR are well advanced in terms of planning and are likely to go ahead. These are given a CoC of 75%.

The projects associated with Development Unclarified CR are less advanced and there is the possibility that these projects are replaced with other (more economically attractive) projects as further work is done. These projects are given a CoC of 50%.

In the case of CR DnV projects the commercial viability is considered to be more challenging than the other CR categories. For the DnV Resources a CoC of 25% has been estimated.

An overview of the CoCs by category are presented in Table 4-7

Category	CoC
Development Pending	75%
Development Unclarified	50%
Development not Viable	25%

Table 4-7 Summary of Ceiba CoCs

4.4.3 Contingent Resource summary

The total Unrisked Contingent Resources for the Ceiba field are presented by CR category in Table 4-8 together with the Chance of Commerciality for each category as presented in Section 4.4.2.4. Note that all Resources are estimated to 1/1/2050.

The risked Contingent Resources for Ceiba generated by applying the COCs to the unrisked CR are presented in Table 4-9.

CR Oil	Gross (MMbbls)			Tullow WI (MMbbls)			CoC
	1C	2C	3C	1C	2C	3C	
Development Pending	3.1	11.1	21.6	0.4	1.6	3.1	75%
Development Unclarified	7.2	19.4	35.1	1.0	2.8	5.0	50%
Development not Viable	19.6	41.7	67.5	2.8	5.9	9.6	25%
Total All CR Categories	**30.0**	**72.2**	**124.1**	**4.3**	**10.3**	**17.7**	

Table 4-8 Ceiba field unrisked Contingent Resource summary

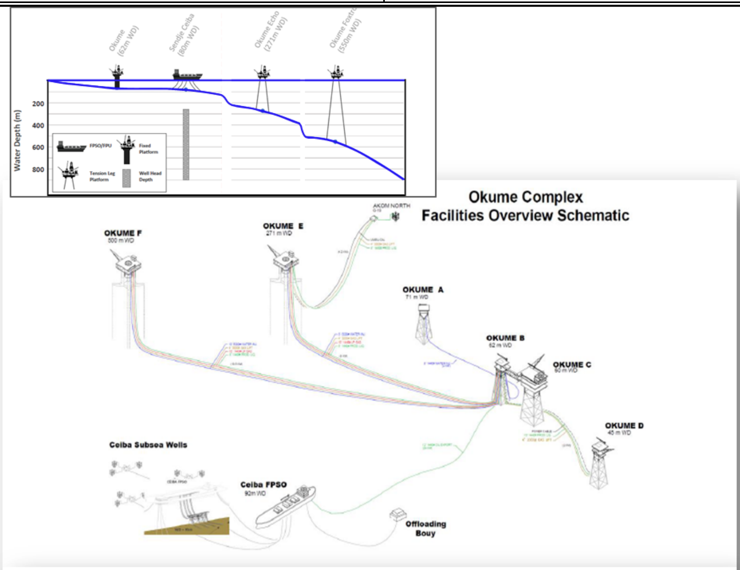
CR Oil	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	2.4	8.3	16.2	0.3	1.2	2.3
Development Unclarified	3.6	9.7	17.5	0.5	1.4	2.5
Development not Viable	4.9	10.4	16.9	0.7	1.5	2.4
Total All CR Categories	**10.9**	**28.4**	**50.6**	**1.6**	**4.1**	**7.2**

Table 4-9 Ceiba field risked Contingent Resource summary

5 Okume Complex

5.1 Hub Overview

Name	Okume Complex
Location	Offshore Equatorial Guinea, Rio Muni Basin
Tullow working interest	Exploration and development working interest of 15% and a revenue working interest of 14.25%
Operator	Trident
Geology	Stacked deepwater turbidite channel and overbank deposit reservoirs of Campanian age (Upper Cretaceous); intra-formational sealing shales. Complex internal geometry, impacting sweep and pressure communication.
Fields in Okume Complex	Elon, Okume, Oveng, Ebano and Akom North
Development & Facilities	4-fixed jacket platforms including a CPF at Elon, 2 tension leg platforms. Processing at Elon CPF. Export via Ceiba FPSO.
Cumulative production to 1/10/2020	238.4 MMbbls
Plans for further development	Significant portfolio of incremental development activities described including workovers and interventions, power upgrade and conversion of wells from gas lift to ESP, Infill wells in Elon, Ebano and Oveng.



The surface assets of Okume Complex are composed of 4 fixed offshore jacket structures (Alpha, Bravo, Charlie and Delta) and 2 mini Tension Leg Platforms (Echo and Foxtrot; also called mini TLPs or TLPs).

Platform	Type & depth	Prod. wells	W.I. wells	Shut in wells	Prod. Oil (bopd)	Prod. W. (bwpd)	W.I. (bwipd)
Alpha	Jacket 71m	0	2	0			6,000
Bravo	Jacket 62m	9	4	0	5,000	28,000	28,000
Charlie	Jacket 60m	0	0	0			
Delta	Jacket 45m	5	0	1	7,000	8,000	
Echo	TLP 271m	8	4	0	4,000	19,000	24,000
Foxtrot	TLP 500m	12	3	0	12,000	23,000	31,000

Table -1 – Existing structures and wells (Production and injection values are indicative)

Figure 5-1 Okume Complex facilities overview

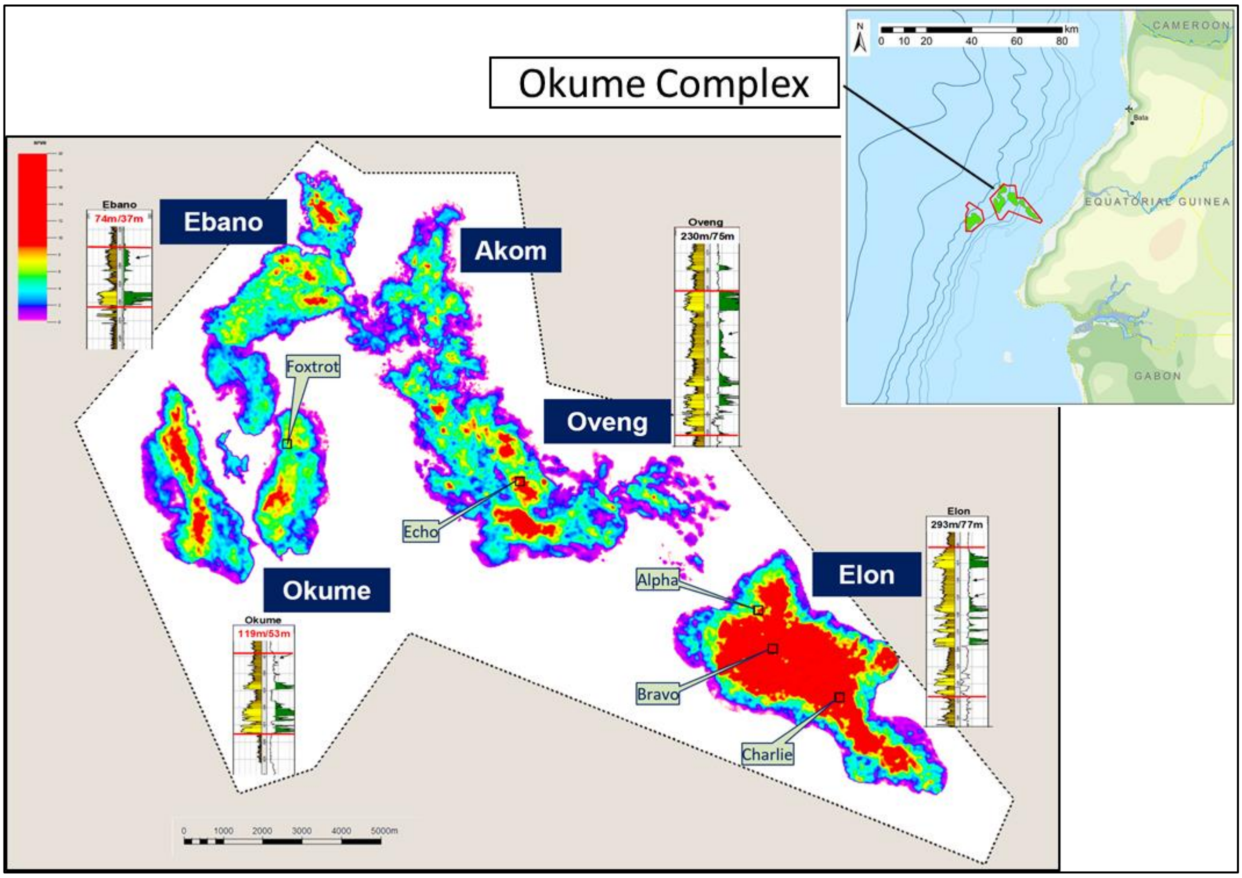


Figure 5-2 Location map and Hydrocarbon pore volume thickness map of the Okume complex fields

The Okume Field gives the Okume Complex its name which comprises four other fields: Elon, Oveng, Ebano and Akom North (Figure 5-2). The fields are located in 50–850 m of water depth straddling the slope break of the southern Rio Muni Basin. Inherited halokinetically-induced topography with mini-basin influenced the turbiditic fairways of the Campanian turbidite channels which entered the area from the southeast. A salt-cored structural high void of Campanian deposits separates Oveng from Okume. More than 15 stacked reservoir units and 10 OWCs have been defined to date. Further post-depositional inversion of the structure has taken place as indicated by thinning of the immediate overburden on the westward approach of the salt dome.

See 4.2 for more details on the tectonic, stratigraphic and sedimentary setting of the Ceiba-Okume area.

5.2 Field Level Overview

5.2.1 Elon Field

Field Name	**Elon**
Geology	Stacked deepwater turbidite channel and overbank deposits.
HCIIP estimate	517-750-1045 MMbbls (TRACS)
Development type	First oil in December 2006. Production from 2 wellhead platforms (plus one additional platform for well injection) tied back to a central processing facility. Recovery mechanism is primarily water injection. Current producers utilise primarily gas lift; ESPs have been installed in three phases
Number of active production & injection wells	14 Producers, 5 Water Injectors
Cumulative production to 1/10/2020	110.2 MMbbls
Current recovery factor (based on 2P STOIIP)	14.7%
Plans for further development	Additional workovers, two phases of infill drilling (also included in CR)

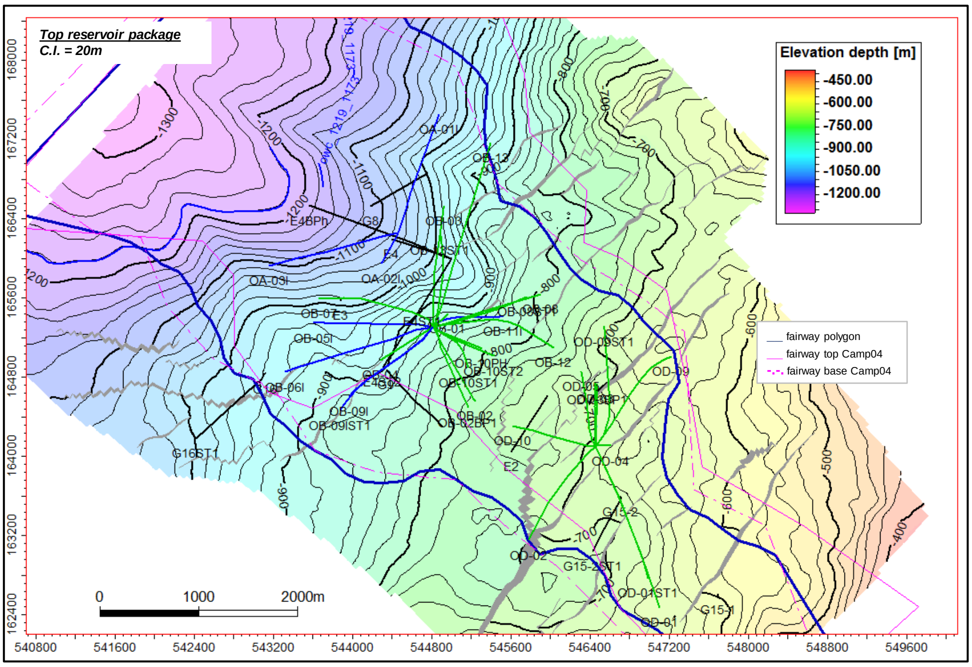


Figure 5-3 Elon depth structure map.

5.2.1.1 Static review and STOIIP estimate

In 2018, TRACS conducted a static review for the Elon field. The review covered the petrophysical, log-derived facies and seismic geobody interpretations. Electrofacies from logs were generated and facies proportions by well extracted. Improvements pertaining to facies proportions in the provided model have been suggested to Tullow and these are being implemented into all fields in the Ceiba-Okume area. GRVs found in the static model provided by Tullow have been adopted. Contacts were confirmed by well data.

Results from the detailed analysis of the Elon field in analogue reservoirs have been used to determine appropriate N/G, porosity and oil saturation levels pertaining to each facies class. N/G associated with thin sand layers (<2 cm) as proven by producing wells has been added. Porosity and saturation are not considered key uncertainties and thus probabilistic variations have been kept small. Based on the review the TRACS in-place volumes are higher than Tullow's: TRACS' 517-750-1045 MMstb (P90, P50, P10) versus Tullow's 453-615-800 MMstb. For the assessment of recovery factors for this review the TRACS figures have been used.

5.2.2 Okume Field

Field Name	Okume
Geology	Stacked deepwater turbidite channel and overbank deposits.
HCIIP estimate	201 MMbbls (Tullow mid case)
Development type	First oil was January 2008 Okume wells are drilled from the Foxtrot TLP, production streams are processed at the Elon CPF. Recovery mechanism is water injection and depletion drive in those sands, which are not adequately supported by injectors.
Number of active production & injection wells	9 Producers, 2 Water Injectors
Cumulative production to 1/10/2020	53.5 MMbbls
Current recovery factor (based on 2P STOIIP)	26.6%
Plans for further development	Intervention campaign (stimulations of 4 wells); ESP conversions in 4 wells.

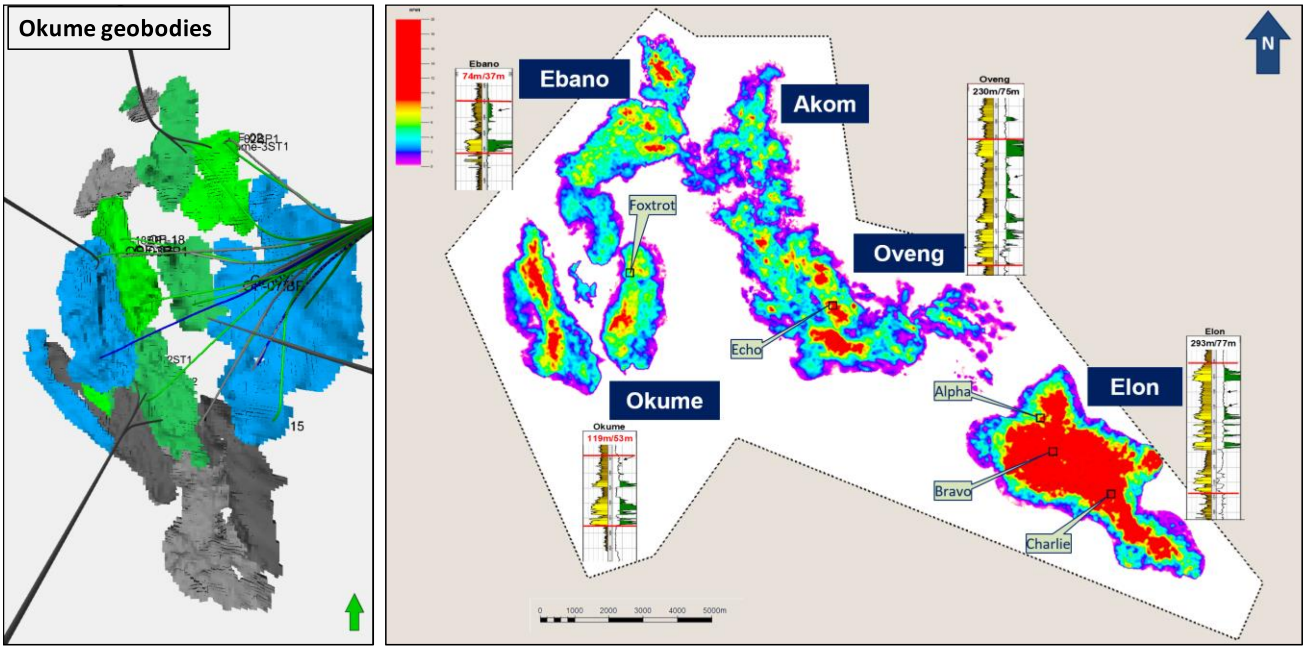


Figure 5-4 Okume geobodies (left) and location of field within the Okume complex (right)

In the absence of an updated Okume static model only a preliminary sense check for STOIIP has been conducted. Analogously to Elon, three reservoir facies types that flow hydrocarbons have been assigned average petrophysical parameters respective to their sedimentary character. Together with their proportions in the provided geobody GRVs, a sense check was provided. TRACS' results largely agree with Tullow's STOIIP assessment and therefore TRACS has adopted Tullow's estimate.

5.2.3 Oveng Field

Field Name	Oveng
Geology	Stacked deepwater turbidite channel and overbank deposits.
HCIIP estimate	233 MMbbls (Tullow mid case estimate)
Development type	First oil 2006 Oveng wells are drilled from the Okume Echo TLP, production streams are processed at the Elon CPF. Recovery mechanism is primarily water injection with depletion drive were producers are not adequately supported by injectors.
Number of active production & injection wells	7 Producers, 4 Water Injectors
Cumulative production to 1/10/2020	56.3 MMbbls
Current recovery factor (based on 2P STOIIP)	24.2%
Plans for further development	Intervention campaign (stimulation of 2 wells and sand consolidation in 2 wells). ESP upgrade in OE-01. Longer term infill wells, 4 targets identified.

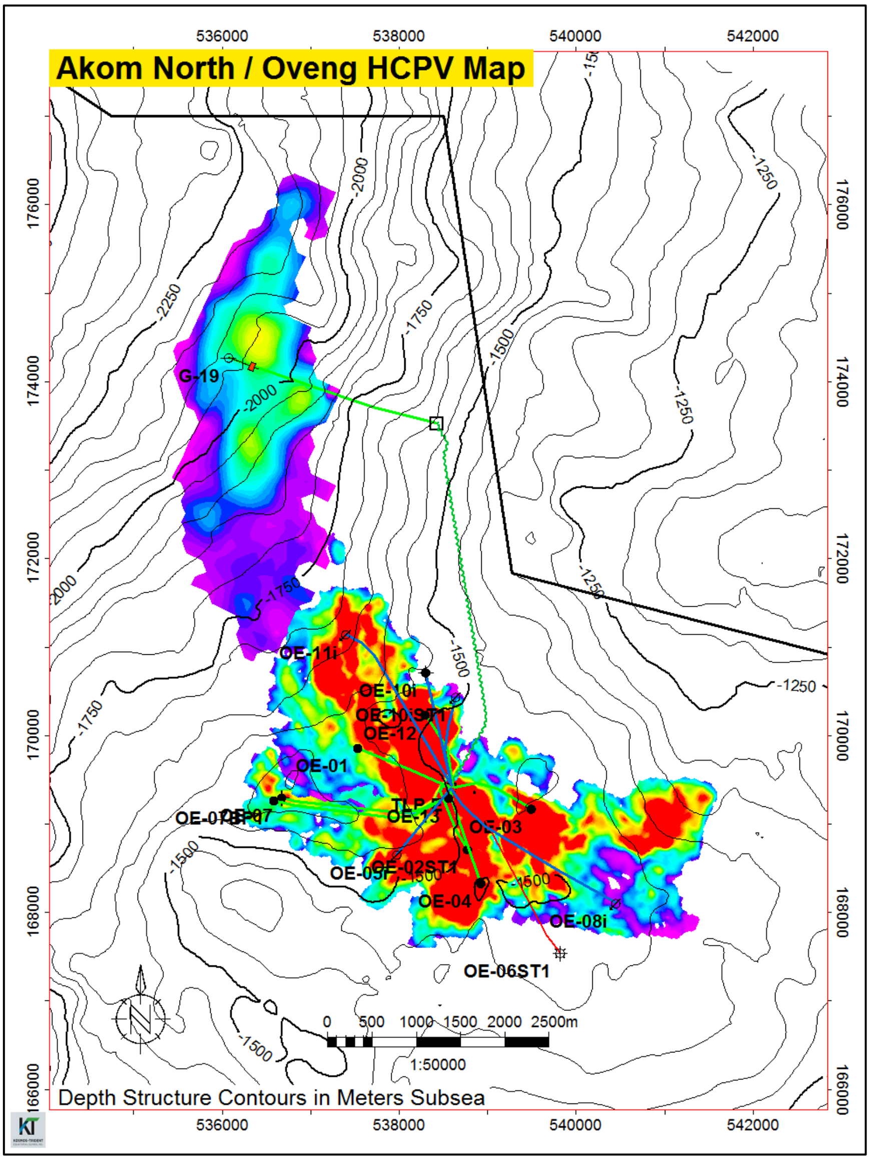


Figure 5-5 Oveng (/Akom North) HCPV map with well locations

Oveng is situated along the sedimentary axis, downdip from Elon field. The Campanian turbidite channel succession was encountered at 1000–2400 m. Five scour surfaces have been identified in 3D seismic. Faults are absent in the static model. Six OWCs are present; four reservoir zones are recognised.

TRACS have assessed petrophysical values of the static model and geobody-penetrating wells to determine parameter ranges for their probabilistic calculations.

Petrophysical statistics from well logs have been compared to static model output. In an additional approach, analogously to Elon, three reservoir facies types that flow hydrocarbons have been assigned average petrophysical parameters respective to their sedimentary character. Together with their proportions in the static model, a further sense check was provided. TRACS' results largely agree with Tullow's STOIIP assessment.

Proportions of facies types indicate Oveng is similar to Ceiba, with a somewhat higher proportion of amalgamated or channel sands.

5.2.4 Akom North

Field Name	Akom
Geology	Stacked Turbidite sandstones
HCIIP estimate	43 MMbbls
Development type	Single subsea development well tied-back to the Echo platform. Depletion drive.
Number of active production & injection wells	1 Producer
Cumulative production to 1/10/2020	7.5 MMbbls
Current recovery factor (based on 2P STOIIP)	17.4%
Plans for further development	Reinstate production well G-19 with the installation of 6-inch pipeline replacement.

In the absence of a static model and in view of the small materiality of the field, TRACS have not reviewed the STOIIP for this field and adopt Tullow's proposed numbers. Figure 5-5, a hydrocarbon pore volume (HCPV) map, shows the location of a single production well.

5.2.5 Ebano Field

Field Name	Ebano
Geology	Stacked Turbidite sandstones
HCIIP estimate	62 MMbbls
Development type	2 well development, wells drilled from Okume Foxtrot TLP; processing at Elon CPF Recovery mechanism is water injection
Number of active production & injection wells	1 Producer: 1 Water Injector
Cumulative production to 1/10/2020	10.8 MMbbls
Current recovery factor (based on 2P STOIIP)	17.5%
Plans for further development	Stimulation and ESP upgrade in well OF-11; One infill drilling opportunity identified.

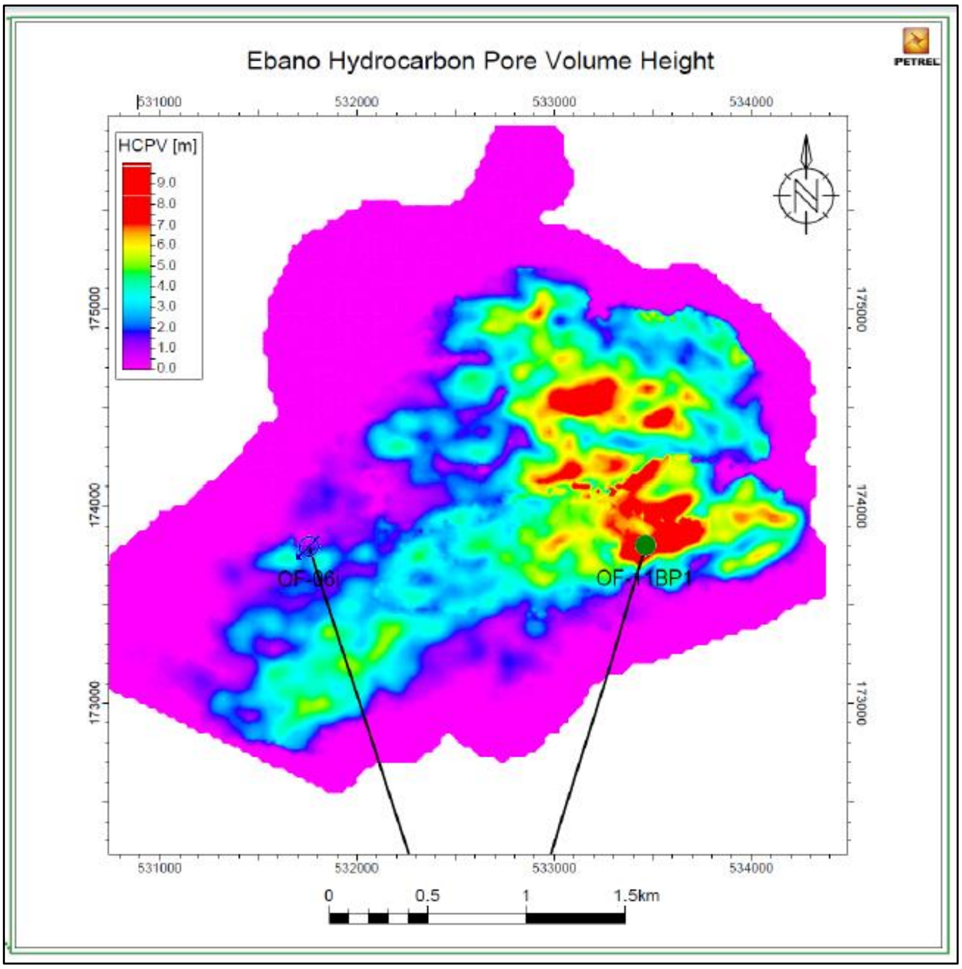


Figure 5-6 Ebano HCPV height map including well locations

In the absence of a static model and in view of the small materiality of the field, TRACS have not reviewed STOIIP for this field and adopt Tullow's proposed numbers.

5.3 Reserves

5.3.1 Introduction

Since Trident took over the Operatorship in 2017 efforts have been focused on improving uptimes and better reservoir management. This has resulted in an improved hub performance since 2017. Longer term production trends can be seen in Figure 5-7.

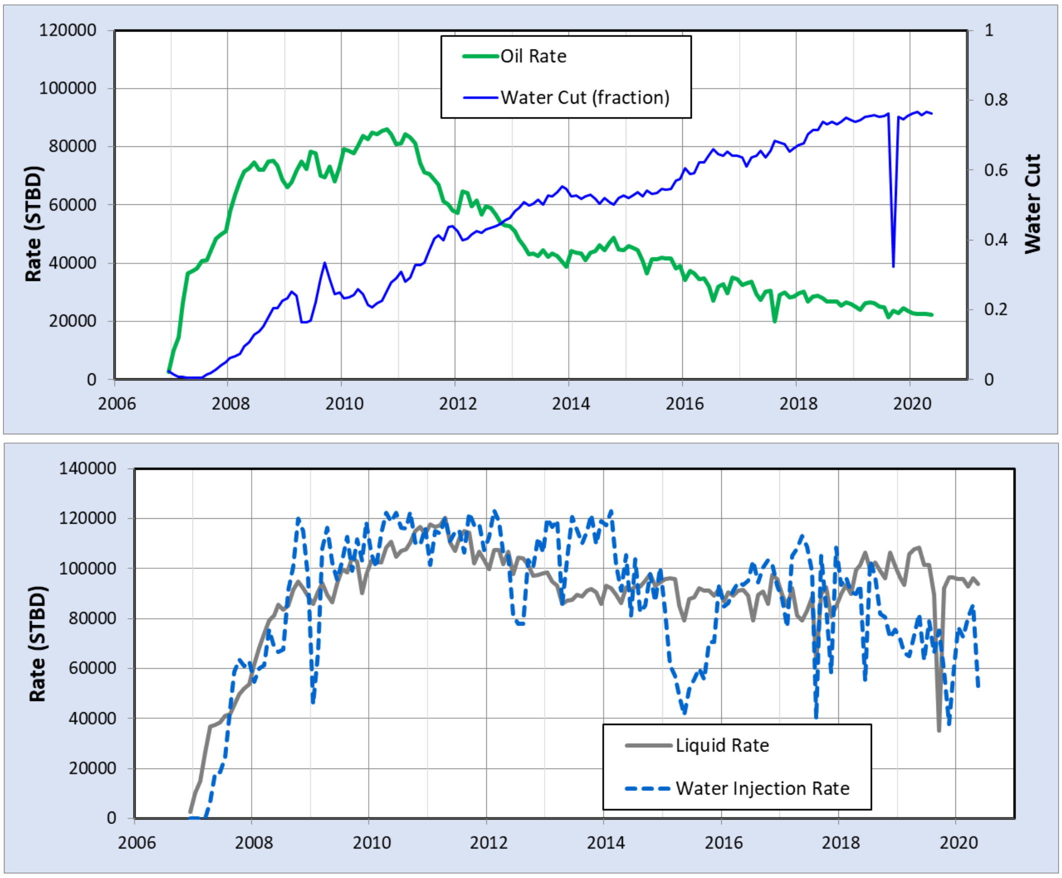


Figure 5-7 Okume Complex Field Production trends

5.3.2 Reserves estimation and production forecasts

5.3.2.1 Developed Producing (NFA)

Tullow provided monthly well by well production data for all Okume Complex wells up to the end of March-2019 and monthly Complex level production data from April 2019 to September 2020. To estimate the reserves associated with the current development the oil producer wells were reviewed and decline curve analysis (DCA) was performed.

The well declines were based on well deliverability with a historical operating efficiency of 95% applied to the final forecast. As described in Section 0, the decline functions consist of a hyperbolic decline profile with shape exponent (b) standardised to 0.2 – 0.6 – 1.0, for low, mid and high, respectively. This range is considered typical for water flood or strong natural water drive reservoirs. The remaining parameters to define the decline were the deliverability and decline rate. The decline rates were taken to be consistent with the range of field declines observed during the field history (Section 0).

Note that Akom North field has only one production well with no water injection support and no clear indication of aquifer support. Therefore b-factors typical for a depletion drive reservoirs, 0.0 – 0.2 - 0.4, were applied for the DCA of the Akom North field.

Due to only the Okume Complex level production data being available from 1/4/2019 the DP forecasts for the Okume Complex were generated by a three-step approach. First, DCA forecasts were generated with well production data up to the end of March-2019. The sum of all wells and fields formed the Okume Complex DP forecast. Then, Okume Complex forecasts were validated against the overall production data in 2019 and 2020. This included the addition of production estimates for 4 ESP upgrade projects completed in 2019. The 2P DP forecast generates a close match to the actual production in the period 1/4/2019 to 1/10/2020. Therefore, the sum of the 2019 DP and 4 ESP upgrade forecasts was adopted as the starting point for the 1/10/2020 Okume Complex DP forecast. Finally, the low, mid and high DP forecasts were updated by applying a range of initial forecast oil rates at 1/10/2020 while still honouring the same recoverable oil volumes for the respective cases as obtained from the well by well decline analysis.

The Okume Complex production history and the resulting DP reserves forecasts obtained from DCA are presented in Figure 5-8.

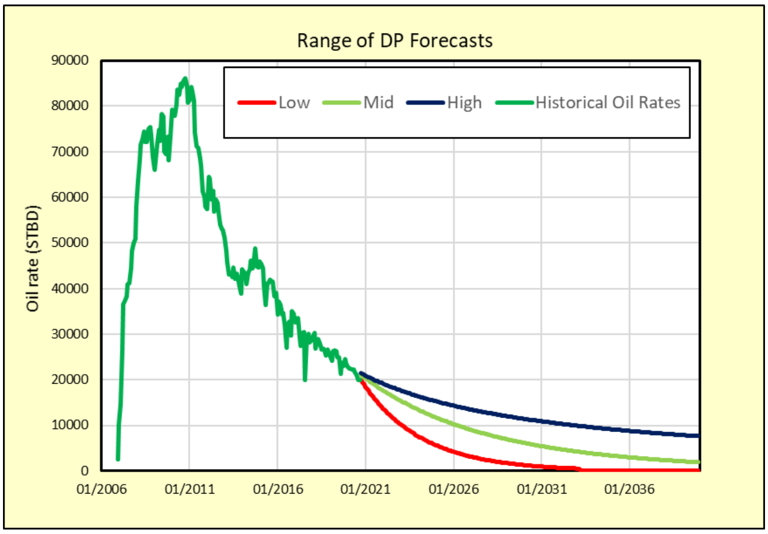


Figure 5-8 Production history, Okume Complex DCA for DP reserves

5.3.2.2 Approved for Development (AD)

The Operator has firm plans with budget approval for a number of development opportunities, which are classified as Approved for Development Reserves. The AD activities summarised in Table 5-1.

Field	Project Name	Category	On production date	Detail
Okume	Stimulation	AD	Jul-20	Stimulation for OF-01,03,05,15
Okume	OF-01_ESP	AD	Nov-20	ESP upgrade
Oveng	Stimulation	AD	Jul-20	OE-01, OE-04L
Oveng	Sand consolidation	AD	Oct-20	OE-12, OE-13
Ebano	Stimulation	AD	Oct-20	Stimulation OF-11
Akon-North	G-19_WO_DW	AD	May-21	Pipeline replacement

Table 5-1 Summary of Approved for development activities

The estimates for the activity production forecasts provided by Tullow (based on Operator estimates) were reviewed. Generally the mid case estimate was adopted but the range of reserves was widened take into account results of similar workovers.

For stimulation of wells and ESP conversions Tullow’s mid case forecast was adopted; however the low and high forecasts took into account a potentially wider range of recovery, 0.2 and 2.0 were applied to the 2P case rather than 0.5 and 1.5 used by Tullow. This is based on general experience with similar well interventions and ESP conversions.

For Akom North pipeline replacement initial rate increases proposed by Tullow were adopted, and decline parameters based on historical performance were applied. The TRACS estimate assumes that in the low case the wax clean out will not be successful long term.

5.3.2.3 Justified for Development (JD)

There are Justified for Development projects are generally based on activities identified by the operator to be executed in 2021. These are summarized in Table 5-2. The activities include the drilling and completion of four infill wells, 3 on Elon and 1 on Oveng.

Field	Project Name	Category	On production date	Detail
Elon	Infill A	JD	May-21	Infill A
Elon	Infill D	JD	Jul-21	Infill D
Elon	Infill C	JD	Sep-21	Infill C
Elon	OB 11i behind pipe	JD	Apr-21	Add perf.
Elon	OD10 inj behind pipe	JD	Apr-21	Add perf.
Elon	OD-03 behind pipe	JD	May-21	Add perf.
Okume	OF-12_ESP	JD	Feb-21	ESP upgrade
Okume	OF-03_ESP	JD	Mar-21	ESP upgrade
Oveng	Oveng A	JD	Dec-21	Infill well

Table 5-2 Summary of Justified for Development activities

Tullow's estimates for activities were reviewed. Generally the mid case estimate was adopted but the range of reserves was widened take into account results of similar workovers (See Section 5.3.2.2).

Tullow/Operator estimates for the Elon infill wells were reviewed and accepted.

The range of production forecasts for the Oveng infill well were generated based on the combination of Operator's low/mid/high forecasts for production from A sand only and A&C sand, to capture the high degree of uncertainty with a wider range. The following cases were used:

- Oveng infill, low: A sand only 1P
- Oveng infill, mid: (A sand 2P + A&C sand 2P)/2
- Oveng infill, high: A&C sand 3P

5.3.2.4 Forecast constraints and operating efficiency

An uptime factor of 0.95 was applied to all forecasts and forecasts were summed as described in Section 0. The production history and range of reserves forecasts for the Okume Complex are shown Figure 5-9.

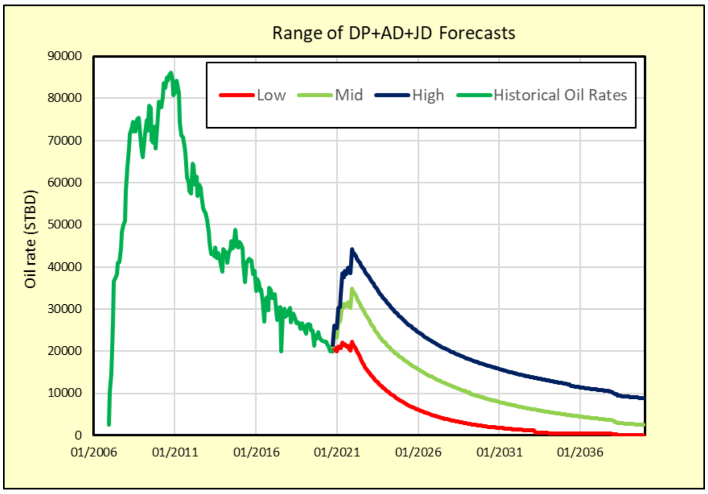


Figure 5-9 Production history and Reserves forecasts for Okume Complex

5.3.3 Cessation of production date

The cessation of production date is the earliest of the production license expiry date, facilities design lifetime or economic limit. License expiry is August 2034. First oil was achieved in 2006. With sufficient preventative maintenance it is likely that the facilities would be able to operate a few years beyond the usual 25 year facilities design lifetime. Okume requires the Ceiba FPSO to remain on station to provide oil storage and export even if the Ceiba topsides facilities are mothballed after Ceiba COP.

5.3.4 Development plans and cost estimates

The Okume Complex fields are processed on the Elon CPF and then sent to the Ceiba FPSO for storage. As a consequence there is an element of shared Opex (and in past years shared Capex) between Okume and Ceiba.

Tullow provided a spreadsheet giving an overview of the annual development well Drillex, facilities Capex and Operational costs for the activities in each reserves category. All costs are quoted gross RT20.

The Operator's 2020 Budget data (reforecast March 2020) was provided along with supporting data for the basis of the shareable (common) Opex. The 2019 and 2020 TCM/OCM slides which included technical and cost detail of the Operator's planned activities were also provided.

The Operator's budget carries a Capex of $44.8MM in 2020, including:

- Okume Upgrade facility project sanctioned in 2019 to increase power, liquid and gas injection capacity on the Okume and Elon platforms to enable new ESP's (included in Opex) to be installed, $30MM (DP)
- Jack-up drilling tangibles, $2.5MM (DP)
- 4D seismic, $8.1MM (DP)
- Akom North G19 flowline installation, $11.6MM (AD)

Tullow provided the November 2020 monthly finance data showing the Capex and Opex allocation to end November and the forecast for December 2020. The Okume allocated Capex spend to end September 2020 was $17.2MM and the forecast for Q4 2020 is $6.8MM.

Post 2020, the Operator carries the following activities and Capex:

- remainder of the G19 flowline installation, $7MM in 2021 (AD)
- Elon A, D and C jack-up wells, total $57.6MM for drilling and completion plus $15MM for surface facilities (JD)
- Oveng A jack-up well, $26.3MM for drilling and completion, $16MM for tieback facilities (JD).

The Operator's 2020 budget quotes the 2020 Routine Opex plus non-capital projects cost (Opex) as $116.7MM, including Okume's share of the shareable Opex.

The Okume 2020 dedicated Opex ($92.0MM) i.e. excluding forecast Opex share, is split as follows:

- Maintenance, Direct Opex & above field, $81.1MM (DP)
- Okume, Oveng and Ebano stimulation projects, $4.4MM (AD)
- Okume OF-01 ESP upgrade, $3.5MM (AD)
- Oveng sand consolidation, $2.5MM (AD)
- Elon OB11i workover, $0.45MM (JD)

In the November finance data the Okume allocated Opex spend to end September 2020 was $76.7MM and the forecast for Q4 2020 is $25.3MM.

The annual dedicated (DP) Opex forecast from 2021 is slightly higher than estimated in the 2019 Reserves Audit, $56.7MM real terms flat (Maintenance, $2.8MM; Direct Opex, $53.7MM and above field, $0.2MM).

In addition the following reserves workover/ intervention costs are forecast post 2020:

- Fixed Opex of $1.2MM per ESP every 2 years from 2021, 3x ESPs in the DP case
- Fixed Opex of $1.2MM per ESP every 2 years from 2022, 1x ESPs in the AD case
- Elon OB11i, OD-10 & OD-3 workovers, $8.7MM in 2021 (JD)
- Okume OF-03 & OF-12 ESP upgrade, $7MM in 2021 (JD)
- Fixed Opex of $2.4MM per year for 2xESP workovers per year from 2022 (JD)

The Operator's March reforecast of the annual Shareable Opex excluding allocated corporate overhead / G&A is $40.0MM (DP). This is assumed real terms flat and is allocated based on the ratio of oil production between Okume and Ceiba. In the November finance data the forecast Shareable Opex for Q4 2020 is $10.8MM.

TRACS consider these costs to be consistent and reasonable.

Tullow advise that there are no tariffs applicable to Okume.

Abandonment provision for cost recovery and tax deduction purposes is included in the economic model. The model indicates that the provision account balance is such that no further payments are required. The Operator's 2019 estimate of the Okume decommissioning cost is $333MM RT19. The Operator quotes an incremental abandonment cost of $5.0MM for the single Oveng A well and tieback (JD). The abandonment cost for the three Elon well tiebacks is assumed to be $15MM (JD).

5.3.5 Reserves summary and valuation

The economic cut-off is determined by the combined Ceiba Okume cashflow considering both fields at the same reserves/resource category i.e. DP & DP, DP+AD & DP+AD etc. The economic cut-off of Okume at 1P/2P/3P assumes Ceiba at its 2P case.

The COP dates used for the estimation of remaining reserves is as follows

Reserves Category	1P	2P	3P
DP	2025	2029	2033
DP+AD	2026	2030	2034
DP+AD+JD	2026	2031	2034

Table 5-3 COP dates for Okume Complex by Reserves Category

The remaining economic reserves at 1/10/2020 are estimated to be:

Oil Reserves by Category	Gross (MMbbls)			Tullow Net Entitlement (MMbbls)			Tullow WI (MMbls)		
	1P	2P	3P	1P	2P	3P	1P	2P	3P
Developed Producing (DP)	19.6	40.7	67.4	2.3	4.8	7.8	2.8	5.8	9.6
Approved for Development (AD)	3.8	9.1	14.9	0.4	1.0	1.6	0.5	1.3	2.1
Justified for Development (JD)	5.7	20.9	36.1	0.7	2.4	3.8	0.8	3.0	5.1
Total All Reserves Categories	**29.2**	**70.7**	**118.4**	**3.5**	**8.1**	**13.3**	**4.2**	**10.1**	**16.9**

Table 5-4 Okume Complex - Reserves summary

The NPV of Okume 1P,2P,3P total reserves is calculated assuming the Ceiba 2P total reserves case. The remaining Tullow WI NPV for Okume total Reserves at the base case and sensitivity cases to the COP date is estimated to be:

	Tullow WI NPV ($MM nom)								
	1P			2P			3P		
Oil Price ($/bbl)	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**	**Base**	**+10**	**-10**
NPV 10%	**0.4**	**19.4**	**-18.8**	**80.0**	**120.4**	**42.4**	**166.7**	**222.4**	**110.9**
NPV 8%	-2.8	16.4	-22.1	80.8	123.7	41.0	176.4	236.7	115.9
NPV 12%	3.1	21.7	-15.9	78.7	116.8	43.1	157.6	209.2	105.8

Table 5-5 Okume Complex Reserves NPV summary

The economics of the JD projects described in Section 5.3.4 considered as a single combined activity demonstrate a positive incremental post tax NPV10 in the 1P case and an IRR exceeding 15% in the 2P case based on the incremental cash flow. The Oveng A, Elon A, D and C jack-up well, Elon OB11i, OD-10 & OD-3 workover, and Okume OF-03 & OF-12 ESP upgrade reserves are considered to be classified as JD.

5.4 Contingent Resources

5.4.1 Overview of activities

Further interventions have been identified and are being matured and are targeted for end 2021/early 2022. These form the basis for Contingent Resources Development Pending (CR-DP); these are in part dependent on the success of AD activities.

Subsurface studies are ongoing and a portfolio of development activities is under review. Infill opportunities for Elon, Oveng and Ebano are being reviewed and are classified as Development Unclarified. Any remaining opportunities have been categorised as Development not Viable.

5.4.2 Estimation of Contingent Resources

Tullow's estimates were reviewed and if deemed reasonable were adopted. Production forecasts were generated for Contingent Resources Development Pending and Development on Hold. No production forecasts were generated for other categories of Contingent Resources.

5.4.2.1 Contingent Resources Development Pending (CR-DP)

Four workovers tentatively planned for 2021 have been identified by the Operator to increase field recovery from the Elon, Okume, Oveng and Ebano Fields. These are primarily ESP upgrades but also include additional perforations in OB-13. An overview of the activities is presented in Table 5-6.

Field	Project Name	Category	On production date	Comment
Elon	OB-13 behind pipe	CR-DP	Sep-21	Add perf.
Okume	OF-15_ESP	CR-DP	Nov-21	ESP upgrade
Oveng	OE-01_ESP	CR-DP	Dec-21	ESP upgrade
Ebano	OF-11_ESP	CR-DP	Oct-21	ESP upgrade

Table 5-6 Summary of CR-DP activities

The Tullow/Operator range of CR for these incremental projects were reviewed and modified where considered appropriate. In particular the range of uncertainty around the mid case was increased compared to the Tullow/Operator supplied estimates. The TRACS estimates are presented in Table 5-7. The recoverable volumes are estimated out to the end of 2050.

Project Area	CR Category	Oil Recovery (MMstb)		
		1C	2C	3C
OB-13 behind Pipe	Development Pending	0.3	1.7	3.4
ESP upgrades		1.2	2.6	4.3
Total		**1.6**	**4.3**	**6.8**

Table 5-7 Range of CR for Okume Complex CR-DP projects

5.4.2.1.1 Production forecasts

A production forecast was generated for the mid (2C) case only. For the ESP conversions (from gas lift) on the Okume, Oveng and Ebano wells, the forecast takes into account performance of Phase 1 ESP conversions.

One additional perforation opportunity has also been identified in Elon Field by the Operator.

For all workovers the mid case decline estimates proposed by Tullow was considered to be reasonable. These were used together with estimate start dates and a facilities uptime factor of 95% to generate the 2C forecast.

The production forecast of DPCR is shown Figure 5-10 Figure 4-9.

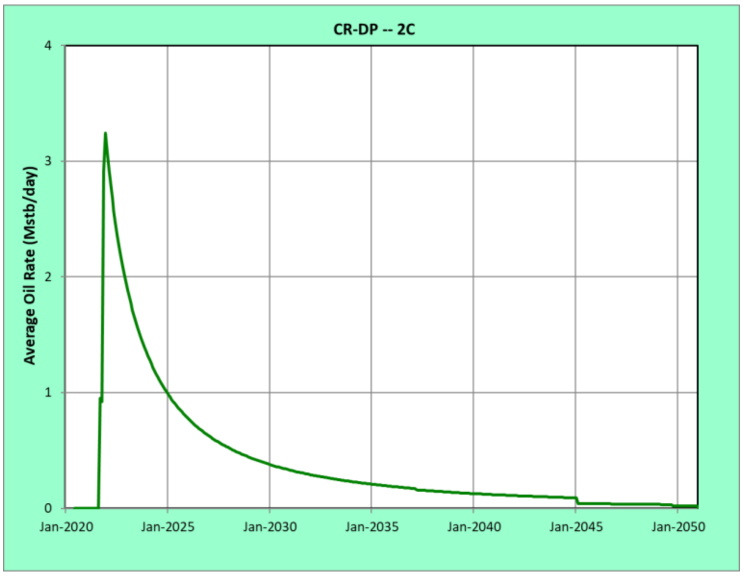


Figure 5-10 Mid case production forecast for CR-DP, Okume Complex

5.4.2.2 Contingent Resources Development Unclarified (CR-DU)

Remaining infill opportunities recognised by the Operator (and Tullow) were provided by Tullow and reviewed. Three infill projects are identified that have been categorised as Development Unclarified. These are assumed to be planned for mid-2023. A summary of the infill activities is provided in Table 5-8.

Field	Project Name	Category	On production date	Comment
Ebano	Infill well	CR-DU	Oct-21	1 infill well
Oveng	Infill	CR-DU	Jan-23	3 infill wells, 2 months between each well starting 1/1/2023
Elon	Infill Phase 4	CR-DU	Jan-24	4 infill wells, 2months between each well starting 1/1/2024

Table 5-8 Summary of CR-DU activities

Tullow’s resource estimates have been reviewed and deemed reasonable for Ebano and Oveng.

Estimates for a Phase 4 infill drilling campaign on Elon, were judged to be high relative to previous phases of drilling and the proposed Phase 3 estimates. Work done previously by TRACS was extrapolated to estimate recovery per well for Phase 4. Are relationship between recovery per well with increasing well count (drill order) was generated (see Figure 5-11). This resulted in average estimated recovery per well of 1.5 MMbbls/well for the 2C case (at licence expiry) ; 1C and 3C cases were based on low and high trend lines, with estimated recovery of 0.4 MMbbls/well in the low case and 2.5 MMbls/well in the high case.

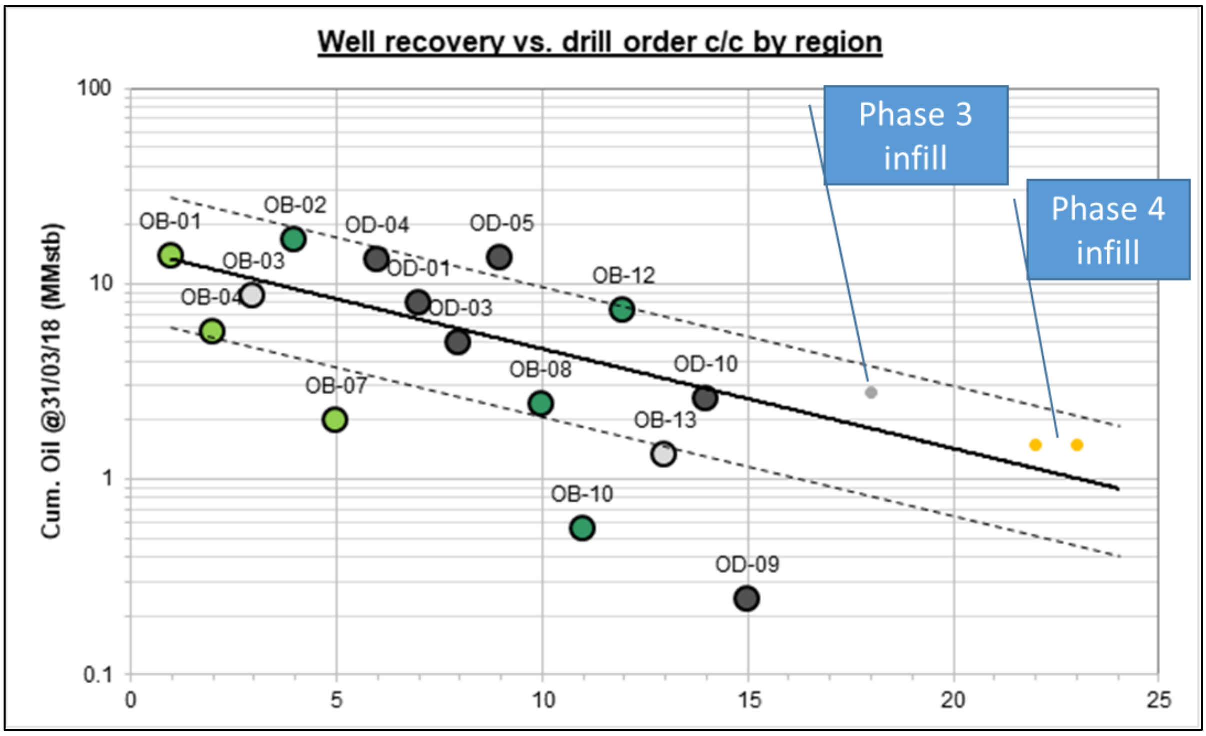


Figure 5-11 Recovery per Elon well with increasing numbers of development wells

The Tullow/Operator range of CR for these incremental projects were reviewed and updated where considered appropriate. The TRACS estimates for these infill opportunities are presented in Table 5-9. The recoverable volumes are estimated out to the end of 2050.

Project Area	CR Category	Oil Recovery (MMstb)		
		1C	2C	3C
Elon Infill	**Development Unclarified**	1.9	7.2	2.3
Oveng Infill		4.9	9.9	4.8
Ebano Infill		1.9	3.8	5.7
Total		**8.8**	**20.9**	**32.6**

Table 5-9 Range of CR for Okume Complex CR-DU projects

5.4.2.2.1 Production forecasts

A production forecast was generated for the mid (2C) CR-DU case only.

For the Elon wells the Operator/Tullow forecast was scaled with the TRACS mid case CR estimate. For the Oveng and Ebano infill wells. Initial oil rates of 200 bpd were estimated for each well and declines fitted to generate the estimated recoverable volumes. A 95% uptime factor was applied to the forecast.

The resulting mid case production forecast for CR-DU is shown in Figure 5-12.

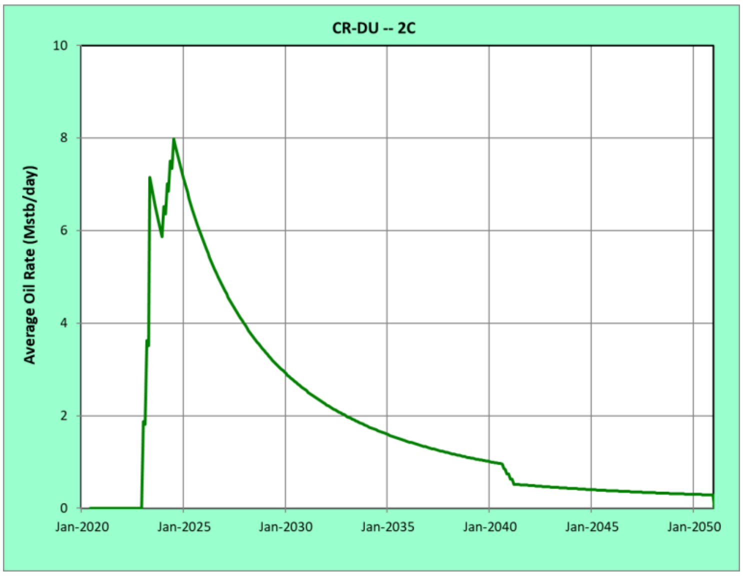


Figure 5-12 Mid case production forecast for CR-DU, Okume Complex

5.4.2.3 Contingent Resources Development not Viable (DnV)

Additional recovery potential has been identified in two main areas:

- Additional infill campaigns: the Operator continues to look for possible infill opportunities and plans to undertake further studies to firm up these opportunities. Potential has been identified on Elon and Ebano
- Recoverable volumes beyond Reserves COP: this captures volumes beyond the reserves COP dates (see Table 5-3) until end 2050. The volumes are estimated using the profiles created for reserves (see Section 5.3.2).

These CR volumes are classified as Development not Viable as there are no current plans for development (infill wells) or are currently shown to be commercially not viable (extension volumes).

There is potential for further infill drilling in the Elon field beyond what has been planned already. To assess the overall Elon recovery factor TRACS has applied a range of recovery factors by facies to the range of STOIIP by facies.

Combining the range of recovery factors with the range of STOIIP by facies results in the range of ultimate recoveries presented in Table 5-10. To generate these the low recovery factors are combined with the low STOIIP, mid with mid and high with high. This is considered reasonable given the large uncertainties associated with the ultimate recovery of the Elon field. The resulting range of ultimate recovery (UR) for the Elon field is presented in Table 5-10.

Elon Field	Low (MM bbls)	Mid (MM bbls)	High (MM bbls)
STOIIP (MM bbls)	517	750	1045
Recovery factor	28%	31%	36%
Ultimate recovery (MM bbls)	145.4	236.2	375.7

Table 5-10 Elon Field – Range of ultimate recoverable volumes

To generate the range of remaining recovery (CR-DnV) associated with further Elon infill drilling the total low, mid and high recoverable volumes associated with all reserves and CR-DP and CR-DU categories have been subtracted from the respective UR volumes (low with low etc.) in Table 5-10.

The TRACS estimates for CR-DnV are presented in Table 4-4. The recoverable volumes are estimated out to 2050.

Project Area	CR Category	Oil Recovery (MMstb)		
		1C	2C	3C
Elon Infill wells	Development not Viable	11.6	62.6	169.7
Life Extension		6.6	19.1	49.7
Total		**18.2**	**81.7**	**219.4**

Table 5-11 Range of CR for Okume Complex CR-DnV projects

5.4.2.4 Chance of Commerciality

The results presented in Section 5.4.2.1 to 5.4.2.3 are unrisked results. In this section a Chance of Commerciality (CoC) is estimated for the CR Resources. The relevant CoCs are then applied to the unrisked numbers to generate risked Resources (see Section 5.4.3).

The projects associated with Development Pending CR are well advanced in terms of planning and are likely to go ahead. These are given a CoC of 75%.

The projects associated with Development Unclarified CR are less advanced and there is the possibility that these projects are replaced with other (more economically attractive) projects as further work is done. These projects are given a CoC of 50%.

In the case of CR DnV projects the commercial viability is considered to be more challenging than the other CR categories. For the DnV Resources a CoC of 25% has been estimated.

An overview of the CoCs by category are presented in Table 5-12.

Category	CoC
Development Pending	75%
Development Unclarified	50%
Development not Viable	25%

Table 5-12 Summary of Okume Complex CoCs

5.4.3 Contingent Resource summary

The total Unrisked Contingent Resources for the Okume Complex are presented by CR category in Table 5-13 together with the Chance of Commerciality for each category as presented in Section 5.4.2.4. Note all Resources are estimated to 1/1/2050.

The risked Contingent Resources for Okume Complex generated by applying the COCs to the unrisked CR are presented in Table 5-14.

CR Oil	Gross (MMbbls)			Tullow WI (MMbbls)			CoC
	1C	2C	3C	1C	2C	3C	
Development Pending	1.6	4.3	6.8	0.2	0.6	1.0	75%
Development Unclarified	8.8	20.9	32.6	1.3	3.0	4.6	50%
Development not Viable	18.2	81.7	219.4	2.6	11.7	31.3	25%
Total All CR Categories	**28.6**	**106.9**	**258.8**	**4.1**	**15.3**	**36.9**	

Table 5-13 Okume Complex field unrisked Contingent Resource summary

CR Oil	Gross (MMbbls)			Tullow WI (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	1.2	3.3	5.1	0.2	0.5	0.7
Development Unclarified	4.4	10.5	16.3	0.6	1.5	2.3
Development not Viable	4.6	20.4	54.9	0.7	2.9	7.8
Total All CR Categories	**10.2**	**34.1**	**76.3**	**1.5**	**4.9**	**10.9**

Table 5-14 Okume Complex field risked Contingent Resource summary

6 Glossary of Terms

$	US Dollars
%	percent
°C	Degrees Celcius
2D	Two Dimensional
3D	Three Dimensional
AD	Approved for Development
AFE	Authorised for Expenditure
API	American Petroleum Institute
AVO	Amplitude Variation with Offset
Av Phi	Average Porosity (from log evaluation)
Av Sw	Average water Saturation (from log evaluation)
bbls	Barrels
Bscf	Billion standard cubic feet of natural gas
bfpd	Barrels of fluid per day
boe	barrels of oil equivalent
boepd	barrels of oil equivalent per day
bopd	barrels oil per day
bpd	barrels per day
bwpd	barrels of water per day
Capex	capital expenditure
CGR	Condensate Gas Ratio
COP	Cessation of Production
CPI	Computer Processed Interpretation (of logs)
CT	Corporation Tax
DCA	Decline Curve Analysis
Den	Density log
D res	Deep resistivity log (deep investigation)
DST	Drill Stem Test
DT	Sonic log
E & A	Exploration & Appraisal
ELT	Economic Limit Test
ESP	Electric Submersible Pump
ft	feet
FTHP	Flowing Tubing Head Pressure
FWL	Free Water Level
FVF	Formation Volume Factor
G & G	Geological and Geophysical
Gas sat	Gas saturation
GDT	Gas Down To
GIIP	Gas Initially In Place
GOR	Gas to Oil Ratio
GR	Gamma Ray log
GRV	Gross Rock Volume
GUT	Gas Up To
GWC	Gas Water Contact
HCDT	Hydro-Carbon Down To
HCWC	Hydro-Carbon Water Contact
IRR	Internal Rate of Return (from MOD cashflows)
JD	Justified for Development
K	Permeability
m	metre
Mbbls	thousand barrels of oil (unless otherwise stated)
Mboe	thousand barrels of oil equivalent
Mbopd	thousand barrels of oil per day
Mcf	thousand cubic feet
Mcfd	thousand cubic feet per day of natural gas
MD	Measured Depth
mD	milli Darcies
MM	million
MMbbls	million barrels of oil
MMstb	million stock-tank barrels of oil
MMbo	million barrels of oil
MMboe	million barrels of oil equivalent
MMcf	million cubic feet of natural gas
MMscfd	million cubic feet of natural gas per day
MOD	Money Of the Day
N/G	Net to Gross
Neu	Neutron log
NFA	No Further Activity
NPV	Net Present Value
OBC	Ocean Bottom Cable
ODT	Oil Down To
OML	Oil Mining Licence
Opex	operating expenditure
OPL	Oil Prospecting Lease
OUT	Oil Up To
OWC	Oil Water Contact
P & A	Plugged and Abandoned
p.a.	per annum
P10	10% probability of being exceeded
P50	50% probability of being exceeded
P90	90% probability of being exceeded
PLT	Production Logging Tool
POS	Possibility Of Success
ppm wt	Parts per million by weight

PRMS	Petroleum Resource Management System
PV	Present Value
PVT	Pressure Volume Temperature
RF	Recovery Factor
RFT	Repeat Formation Tester
RROR	Real Rate of Return (from RT cashflows)
RT	Real Terms
SG	Specific Gravity
SMT Kingdom	a PC-based interpretation workstation
SPE	Society of Petroleum Engineers
sq km	square kilometres
S res	Short resistivity log (shallow investigation)
ss	subsea
STOIIP	Stock Tank Oil Initially In Place
Sw	water Saturation
Swavg	average water Saturation
TD	Total Depth
tvd	true vertical depth
TVDSS	true vertical depth subsea
tvt	true vertical thickness
TWT	Two-Way Time
WI	Working Interest

Appendix A Production Forecast (for Reserves)

Year	1P	2P	3P
	Oil	Oil	Oil
	Mstbd	Mstbd	Mstbd
2020	4.9	5.2	5.4
2021	16.1	19.0	20.0
2022	12.0	16.6	18.4
2023	8.9	14.4	17.0
2024	6.7	12.6	15.8
2025	5.0	11.0	14.8
2026	3.7	9.7	13.9
2027	2.7	8.5	13.1
2028	2.0	7.5	12.4
2029	1.5	6.6	11.7
2030	1.1	5.8	11.2
2031	0.8	5.1	10.6
2032	0.6	4.5	10.2
2033	0.1	4.0	9.7
2034	0.0	2.4	6.3

Table A-1 Okume Complex -- Developed Producing Production Forecasts

Note: Annual rate in 2020 based on oil production from 01/10/2020 to 31/12/2020 divided by 366 days

Year	1P	2P	3P
	Oil	Oil	Oil
	Mstbd	Mstbd	Mstbd
2020	5.6	6.4	7.2
2021	18.0	22.5	25.2
2022	13.5	19.6	22.9
2023	10.0	16.9	20.7
2024	7.4	14.6	19.0
2025	5.5	12.7	17.5
2026	4.1	11.1	16.2
2027	3.0	9.7	15.1
2028	2.3	8.5	14.2
2029	1.7	7.5	13.4
2030	1.2	6.6	12.6
2031	0.9	5.8	12.0
2032	0.7	5.2	11.4
2033	0.2	4.6	10.8
2034	0.0	2.8	6.9

Table A-2 Okume Complex -- Developed Producing + Approved for Development Production Forecasts

Note: Annual rate in 2020 based on oil production from 01/10/2020 to 31/12/2020 divided by 366 days

Year	1P	2P	3P
	Oil	Oil	Oil
	Mstbd	Mstbd	Mstbd
2020	5.6	6.4	7.2
2021	21.1	29.7	36.2
2022	18.3	31.0	40.6
2023	12.8	24.5	34.8
2024	9.5	20.1	29.9
2025	7.1	17.1	26.2
2026	5.4	14.7	23.3
2027	4.2	12.8	21.0
2028	3.3	11.2	19.2
2029	2.6	9.7	17.6
2030	2.0	8.5	16.4
2031	1.6	7.5	15.3
2032	1.3	6.7	14.3
2033	0.7	5.9	13.5
2034	0.4	3.6	8.5

Table A-3 Okume Complex -- Developed Producing + Approved for Development + Justified for Development Production Forecasts

Note: Annual rate in 2020 based on oil production from 01/10/2020 to 31/12/2020 divided by 366 days

Year	1P	2P	3P
	Oil	Oil	Oil
	Mstbd	Mstbd	Mstbd
2020	2.5	3.0	3.4
2021	8.4	10.4	12.2
2022	6.4	8.6	10.5
2023	5.0	7.3	9.3
2024	4.0	6.2	8.3
2025	3.2	5.4	7.5
2026	2.5	4.8	6.9
2027	2.1	4.2	6.3
2028	1.7	3.8	5.9
2029	1.4	3.4	5.5

Table A-4 Ceiba -- Developed Producing Production Forecasts

Note: Annual rate in 2020 based on oil production from 01/10/2020 to 31/12/2020 divided by 366 days

Year	1P	2P	3P
	Oil	Oil	Oil
	Mstbd	Mstbd	Mstbd
2020	2.8	3.4	4.0
2021	10.7	13.6	16.5
2022	8.3	11.6	14.7
2023	6.2	9.5	12.7
2024	4.8	7.9	11.1
2025	3.8	6.7	9.8
2026	2.9	5.7	8.7
2027	2.4	5.0	7.9
2028	1.9	4.4	7.2
2029	1.5	3.9	6.6

Table A-5 Ceiba -- Developed Producing + Approved for Development Production Forecasts

Note: Annual rate in 2020 based on oil production from 01/10/2020 to 31/12/2020 divided by 366 days

Appendix B Production Profiles for 2C Contingent Resources

Year	Okume Complex Incremental 2C Oil (Mstb/d)		
	CR-DP	CR-DU	Total CR
2020	0.0	0.0	0.0
2021	0.7	0.0	0.7
2022	2.5	0.0	2.5
2023	1.6	5.2	6.8
2024	1.2	7.3	8.4
2025	0.9	6.4	7.3
2026	0.7	5.2	5.9
2027	0.6	4.3	4.9
2028	0.5	3.7	4.1
2029	0.4	3.1	3.6
2030	0.4	2.7	3.1
2031	0.3	2.4	2.7
2032	0.3	2.1	2.4
2033	0.2	1.9	2.1
2034	0.1	1.1	1.3

Table B-1 Okume Complex 2C incremental oil forecasts

Year	Ceiba Incremental 2C Oil (Mstb/d)		
	CR-DP	CR-DU	Total CR
2020	0.0	0.0	0.0
2021	0.0	0.0	0.0
2022	1.7	0.0	1.7
2023	2.9	2.9	5.8
2024	2.5	5.2	7.7
2025	2.2	4.6	6.8
2026	1.9	4.0	6.0
2027	1.7	3.6	5.3
2028	1.6	3.2	4.8
2029	1.4	2.9	4.3

Table B-2 Ceiba 2C incremental oil forecasts

Appendix C Summary of 2018 SPE Petroleum Resources Classification

The following table has paragraphs that are quoted from the 2018 SPE PRMS Guidance Notes and summarise the key resources categories, while Figure B-2 shows the recommended resources classification framework

Class/Sub-class	Definition
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.
On Production	The development project is currently producing and selling petroleum to market.
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable due to one or more contingencies.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time due to limited production potential.
Prospective Resources	Those quantities of petroleum which are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.
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.
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.

Table C-1 Summary of 2018 SPE Petroleum Resources Classification

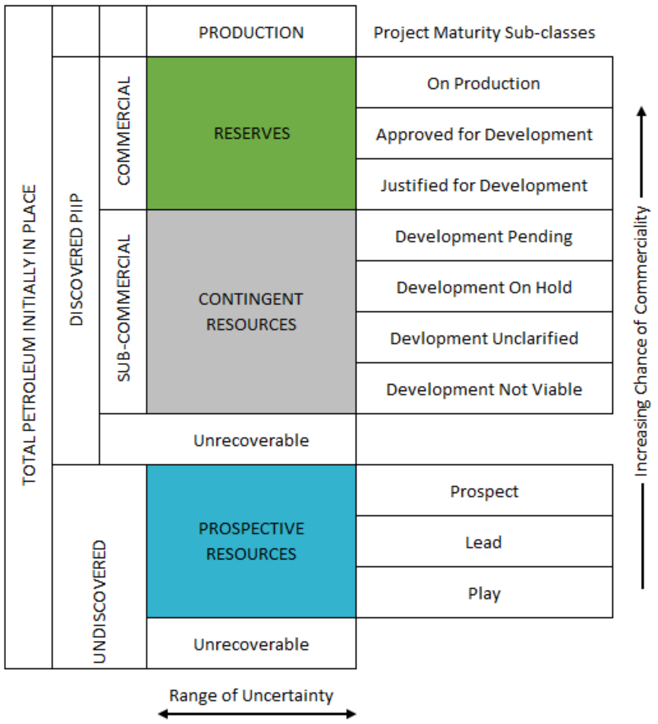


Table C-2 SPE PRMS Petroleum Resources Classification Framework