Audit of Petroleum Interests of Tullow Oil

At 31st December 2021

Tullow Oil plc

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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

Mike Wynne

Qualification

TRACS International Limited ("TRACS") was founded in 1992, and currently has over 50 petroleum engineers, geoscientists and petroleum economists. TRACS has extensive Reserves and asset valuation experience and are recognised as industry reserve, risk and valuation experts. Note that in 2008, TRACS was bought by AGR and became AGR TRACS International Ltd. ("AGR TRACS" a wholly owned subsidiary of AGR). In April 2019, AGR TRACS was sold and became TRACS International Ltd. (an independent company). All contracts and ownership rights to prior work performed by AGR TRACS were retained by TRACS during that transaction.

The Tullow asset review and evaluation was performed by senior TRACS staff with an average 30+ years in the oil and gas industry. The team members all hold at least a bachelor's degree in geoscience, petroleum engineering or related discipline. The preparation of this report has been supervised by Dr. Mike Wynne. Dr. Wynne has over 25 years of experience in the evaluation of oil and gas fields, preparation of development plans and assessment of Reserves and Resources.

This assessment has been conducted within the context of the TRACS understanding of the effects of petroleum legislation, taxation, and other regulations that currently apply. However, TRACS is not in a position to attest to property title, financial interest relationships or encumbrances thereon for any part of the appraised properties.

It should be understood that any determination of resource volumes, particularly involving petroleum developments, may be subject to significant variations over short periods of time as new information becomes available and perceptions change. This is particularly relevant to exploration activities which by their nature involve a high degree of uncertainty.

All volumetric calculations are based on independent assessment undertaken by TRACS using data provided to TRACS. The reservoir properties input to the volumetric calculations and the associated volume uncertainty ranges are based on TRACS experience over more than 20 years of performing evaluations, and the statement on risking in this report represents the independent view of TRACS.

TRACS has carried out this work using the June 2018 SPE/WPC/AAPG/SPEE Petroleum Resources Management System (PRMS) as the standard for classification and reporting. A summary of the PRMS is found in Appendix A.

TRACS will receive a fee for the preparation of this report in accordance with normal professional consulting practices. This fee is not dependent on the findings of this report and TRACS will receive no other benefit for the preparation of this report.

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This report is for the use of Tullow and its bankers and financial advisors. TRACS hereby consents to using the report or references to the report in any applicable disclosure document, provided that no portion be used out of context or in such a manner as to convey a meaning which differs from that set out in the whole. The report may not be used for any other purpose without TRACS' prior written approval.

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1 Portfolio Overview

1.1 Introduction

The Tullow oil and gas assets comprise of a large and diverse portfolio of producing fields, development opportunities and exploration prospects. This report addresses the auditing and valuation of the Tullow Reserves. All Tullow Reserves are associated with producing fields located in West Africa, with key assets in Ghana, Gabon and Côte d'Ivoire. They include a mix of oil and gas assets and fields newly onstream as well as those with long established production. Development opportunities have been identified for many of the assets that are either under appraisal or where development plans are established but are yet to be executed.

In arriving at the economic valuation in this report TRACS have assessed 100% of the Tullow Reserves estimates. TRACS performed a comprehensive audit of the assets presented in this document between July 2021 and December 2021 through a mixture of verifying Tullow assumptions and forecasts, adapting assumptions where felt necessary, and performing original technical and commercial analysis where felt justified.

A more detailed description of the Tullow portfolio by geographical area is presented in the following sections.

1.1.1 Ghana assets

The Ghana fields and discoveries in the Tullow portfolio are located offshore Ghana. The key fields addressed in this report are Jubilee, Tweneboa, Enyenra and Ntomme. The last three fields are generally referred to as the TEN fields.

Tullow is the operator of the Jubilee and TEN fields with working interests of 35.48% and 47.175%, respectively. A unitisation agreement covering the Jubilee field is also in place. This was agreed by the partners of the West Cape Three Points and Deep Water Tano licenses. The TEN fields lie entirely within the Deep Water Tano license.

All fields are made up of late Cretaceous Turonian reservoirs of good to varying quality. There is good quality oil in the Jubilee, Enyenra and Ntomme reservoir units, varying from 34 to 38 degrees API. Tweneboa field primarily contains retrograde gas condensate.

The Jubilee field was discovered in 2007 by Mahogany-1 and appraised by a further 3 wells prior to field development. The field is subdivided into the main (MH1, MH4 and MH5) and secondary (MH3, MH2 and LM3) reservoirs units.

The Jubilee field commenced production in November 2010. There are currently 35 development wells in the field, 19 producers, 13 water injectors and 3 gas injectors. The wells are tied back to a floating production storage and offloading facility (FPSO) utilising subsea infrastructure consisting of 10 subsea manifolds and associated flowlines. A gas pipeline is also installed and utilised for wet gas export to the Ghana National Gas Company (GNGC). This commenced in November 2014.

The TEN fields were discovered by the Tweneboa-1 well in March 2009 with subsequent discoveries of the Enyenra and Ntomme oil pools in September 2010 and March 2012. To date only the Enyenra and Ntomme fields have been developed and are being produced through a combination of water injection and gas injection (Ntomme only) recovery mechanisms. Note there is no gas export planned for TEN going forward as all gas will be re-injected into Ntomme to support oil recovery.

The fields commenced production in August 2016. There are currently 8 wells in Enyenra (4 producers, 4 injectors) and 8 wells in Ntomme (4 producers, 2 water injectors and 2 gas injectors). The development of TEN utilises a FPSO with production and injection wells connected via a subsea network of manifolds and flowlines tied back to the FPSO.

In Ghana both the West Cape Three Points and the Deep Water Tano blocks are governed by Petroleum Agreements with fiscal terms based on a royalty and tax system. The royalty rate that applies to the gross production is delivered in kind. Income tax is charged after allowing for royalty payments, operating costs and the depreciation of capex.

The Government of Ghana, through its national oil company GNPC, has a 10% initial interest in both Agreements which costs are "carried" during the exploration and development phases. GNPC also has an additional interest (5% in the TEN Field and 3.64% in the Jubilee Field) where it is responsible for development and production costs.

In addition, the Ghanaian Government is entitled to additional oil entitlements from the Contractor's share of crude oil on the basis of the after royalty, after tax, inflation adjusted rate of return achieved by the Contractor from a development and production area. The rate of return is calculated based on an agreed formula.

1.1.2 Gabon Assets

The Gabon fields and assets are mainly located offshore Gabon, with the exception of the Ezanga, Echira, Niungo, Oba and M'Oba assets which are located onshore. All assets are non-operated. The fields reviewed as part of the audit are listed below together with the relevant operator of the asset and Tullow's working interest.

Asset	Operator	Tullow WI
Echira	Perenco	40%
Limande	Perenco	40%
Oba	Perenco	10%
M'Oba	Perenco	24.3%
Turnix	Perenco	27.5%
Ezanga	Maurel & Prom (M&P)	7.5%
Niungo	Perenco	40%
Tchatamba Complex	Perenco	25%
Simba	Perenco	57.5%

Table 1-1 Summary of Gabon assets

The Ezanga Complex consists of 8 fields as presented in Table 1-2.

License	Field
Ezanga Complex	Onal
	Maroc North
	Maroc
	Gwedidi
	Omko
	M'bigou
	Ezmab
	Ezni

Table 1-2 Ezanga Complex fields

The Ezanga Complex commenced oil production in 2009. There are currently a total of 147 active wells in the fields: 97 producers and 50 water injectors. The Ezanga fields are tied back to a central processing facility at Onal. The oil is exported via 2 routes. Heating of export oil is required to manage a high wax appearance temperature.

The two main formations for the Ezanga fields are the Grès de Base and Kissenda formations. The Grès de Base represents the main reservoir rock of the western to north-western pools (Onal, M'bigou, Gwedidi and Ezmab), while the Kissenda Formation provides the main reservoir for the eastern and south-eastern fields (Maroc N, Maroc, Omko and Ezni). There is reasonable quality oil in all fields, varying from 32 to 37 degrees API. However, the crude is waxy with viscosities between 1.8 and 6 cP. The main drive mechanisms is through water injection assisted by artificial lift.

The Tchatamba complex consists of three fields: Tchatamba Marin, Tchatamba South and Tchatamba West. The fields are located approximately 30 km offshore Gabon within water depths of around 50 m and are fully contained within the Kowe license.

The fields are subdivided into four main producing reservoirs: Anguille, Azile, Cap Lopez and Madiela. Madiela is the primary reservoir with the largest recovery to date. There is good quality oil in all reservoirs, varying from 35 to 44 degrees API. The primary drive mechanism is strong aquifer support.

The Tchatamba Complex commenced production from Tchatamba Marin in 1998, followed by South in 1999 and West in 2000. There are currently a total of 19 development wells in the fields, all producers. The development of the fields consists of two mobile offshore production units (MOPU) at Marin, a processing platform at South, which is tied into Marin and a wellhead platform at West tied back to Marin. The oil is exported via a pipeline to shore and on to the Fernan Vaz floating storage and offloading facility (FSO).

The Simba field is located offshore Gabon, approximately 25 km west of the Tchatamba fields. The field was discovered in 2003 by Simba-1. Simba is produced utilising two producing wells: Simba-2 and Simba-3. Simba-2 is a crestal oil producer, which was drilled and completed in December 2018 and came online in January 2019. A second producer, Simba-3, was completed in 2021 and came onstream in September 2021.

The wells produce to a wellhead platform (WHP) in 80m water depth. The WHP is tied back to the Tchatamba MOPU-B platform via a multiphase pipeline.

The Simba field currently produces from the Madiela A Upper reservoir. The reservoir contains an undersaturated light oil with an API of ~ 45 API. The reservoir is good quality Cretaceous shoreface sandstone with permeabilities ranging from 50 to 1400 mD. The recovery mechanism is predominately through strong aquifer drive.

The Echira field is located onshore Gabon approximately 15 km southwest of the Rabi field. The reservoir intervals are in the Lower Cretaceous lacustrine/fluvial Dentale and the coastal marine Gamba sands or Vembo shales. The field came onstream in 1992. There are currently 14 active wells in Echira; 7 producers and 7 water injectors. Production is supported by a combination of aquifer drive, water injection with electric submersible pumps (ESP) lifting.

The Echira field is produced through the Echira facilities, which are an important hub for other Perenco operated fields. Investment is ongoing to ensure the continued operation of the facilities.

The Niungo field is located onshore Gabon approximately 22 km east of the Echira field. The reservoir intervals are within the pre-salt Lower Cretaceous reservoirs, mixed fluvial and coastal marine sandstones of the Gamba Fm.

The field came onstream in 2002. There are currently 31 active wells: 27 producers and 4 water injectors. Production is supported by water injection with ESP and Progressive Cavity Pump (PCP) lifting. The field is currently produced through the Echira hub facilities.

The Turnix field is located offshore Gabon in a water depth of around 25m. The main reservoir interval in the Turnix field is the N'TchenqueOcean (Anquille equivalent). The Pointe Clairette formation is the secondary reservoir in the field. Both reservoirs are turbidite reservoirs.

The field came onstream in 1998. There are currently 6 producing wells. Production is supported by a combination of natural aquifer drive and ESP/gas lift. There are no injection wells. The Turnix field produces to the Intrepid jack-up facility. Fluids are separated on board the Intrepid, water is disposed of overboard, and crude oil is exported to the Bon Bateau floating storage unit (FSU).

The Limande field is located 40km south of Port Gentil 12km west of the Ogooué estuary in 50-100m water depth. The field was discovered in 1991 and came on stream in 1998. The field has 8 oil producers and 2 water injectors. The reservoir drive is assisted by a secondary gas cap and ESP lift. The field is a 3-way dip closure with the main aquifer being the N'Tchengue Ocean.

Facilities are installed on a fixed jacket platform. Crude is exported via a new pipeline to Turnix and exported with the Turnix oil to the Bon Bateau FSU.

The Oba field is located onshore Gabon approximately 135 km south east of the city of Port Gentil. The reservoir intervals are located in the Ceno-Turonian and Lower Senonian (Upper Cretaceous) stacked shoreface and carbonate shoal reservoirs of the Cap Lopez, Azile and Milango formations.

The Oba field came onstream in 2006. There are currently 35 active wells in Oba: 22 producers and 13 water injectors. Production is supported by natural aquifer drive, water injection and ESP/PCP lifting. Oba produces via an 8-inch pipeline to the Batanga field where the oil is processed.

The M'Oba field is located onshore Gabon to the North of the Oba field, approximately 135 km south east of the city of Port Gentil. The reservoir intervals are located in the Lower Milango formation comprising a mixture of sand, dolomite and limestone, deposited in a shallow marine environment.

The M'Oba field was discovered in 2013 by MOBA-1 and came onstream in 2015. There are currently 3 production wells in the field. Production is supported by a weak natural aquifer drive. The wellhead fluids are produced to the Oba facilities.

The majority of Tullow's assets in Gabon are covered by a Protocol with the Government of Gabon that means they are ring fenced and treated as one entity for tax purposes. The Protocol fields pay a cash royalty of 12% on any oil and gas revenues. In addition, they pay income tax at a rate of 50% on the combined fields' revenues after allowing for royalty, operating costs and capital depreciation. Capital is depreciated over 3 years.

The remaining fields are governed by Production Sharing Contracts. Royalty applies to these fields. Between 70 and 75% of operating and capital costs can be cost recovered. Profit oil is then shared with the Government with the contractor at a rate dependent on the level of production.

1.1.3 Côte d'Ivoire Assets

Espoir is located offshore Côte d'Ivoire in 400 to 600m of water. The Espoir asset consists of two oil fields – East Espoir and West Espoir. First oil produced was from East Espoir in 1982. CNR operate the license and Tullow hold a 21.33% revenue working interest.

Espoir reservoir units are of Late Albian reservoir age with a series of stacked immature sandstones deposited by deep marine gravity flows and turbidity currents within a restricted basin. There are two main reservoir units under development: URU and LRU.

The Espoir development consists of 2 wellhead towers tied back to the Espoir FPSO. Each wellhead tower (WHT) has 12 well slots, currently all in use with the West WHT located 5.5km from the FPSO. The FPSO, which is leased, is turret moored in ~120m water depth, 19km from shore. The FPSO provides water injection and gas lift to each WHT.

Oil is exported via tandem oil offloading and gas via a 10" pipeline to the Adjue Onshore Terminal. From there gas is exported to two onshore gas pipelines shared with the Lion & Panthere (CI-11) and Foxtrot (CI-26) developments.

The existing development comprises 19 active wells over the whole of Espoir. There are 8 producers and 2 water injectors in West Espoir and a further 6 producers and 3 water injectors in East Espoir. Production was initially under depletion and is now supported by water injection.

Following a FPSO tank entry incident in January 2021 and resulting changes to the tank entry procedures the DNV granted an extension of class to April 2022, which aligns with the current FPSO contract expiry date. A task force made up of JV members is due to make a decision on the continued operation of Espoir beyond this date based on the commerciality of the required future investment in the Espoir field (including additional development) and the Espoir FPSO, by 21st March 2022.

The next planned development is the Phase IV drilling campaign in 2022 which includes a further 7 infill wells, 2 producers in West Espoir and 2 producer and 3 injectors in East Espoir.

The FPSO remediation and Phase IV drilling costs, coupled with currently unresolved in-country political issues risk the production beyond April 2022 being classified as (JD) reserves.

The Espoir field in Côte d'Ivoire is governed by a Production Sharing Contract (PSC). The Espoir PSC is divided into Special Zone "E" and the area Outside of Special Zone "E." Special Zone "E" was designated as such because it contains the Espoir Field. The National Oil Company, Petroci has a 20% participating interest under the Espoir PSC in Special Zone "E" and pays no petroleum costs with respect to half of such interest.

Under the Espoir PSC, the contractor is entitled to recover annually costs incurred in petroleum operations (which includes exploration, appraisal, development and exploitation costs). After the deduction of petroleum costs, the remaining crude oil is profit oil and is distributed between the Government of Côte d'Ivoire and the contractor.

2 Reserves

This section presents the TRACS estimates for developed and undeveloped Reserves associated with the Tullow assets. The reference date for the Reserves is 31st December 2021. The total oil and gas Reserves (split by category) associated with the respective assets as attributable to Tullow on 31st December 2021 are presented in Table 2-1.

Reserves Category	Oil (MMstb)	Gas (Bscf)	Total Oil Equivalent (MMboe)
	2P	2P	2P
Developed Producing (DP)	112.4	63.3	122.9
Approved for Development (AD)	36.7	24.2	40.7
Justified for Development (JD)	58.0	58.4	67.8
Total Reserves	**207.1**	**145.9**	**231.4**

Table 2-1 Oil and gas Reserves for all assets attributable to Tullow

The Reserves shown in Table 2-1 present the volumes in the Jubilee field, TEN fields, Tchatamba Complex, Ezanga Complex, Oba field, M'Oba field, Turnix field, Echira field, Limande field, Niungo field, Simba field and Espoir fields.

The Reserves associated with the respective assets audited by TRACS are presented in the following sections.

2.1 Jubilee Field

The Tullow Reserves for the Jubilee field are based on three main components:

- Developed (on production) Reserves (DP) utilising the current wells
- Approved for Development reserves (AD) associated with the Jubilee South East Phase 1 project, further Jubilee infill wells, primarily in the MH4 reservoir, and the Partial Expansion project.
- Justified for Development reserves (JD) are associated with the Jubilee Base Development project which targets further development in the MH4/3 NE area, the Jubilee South East Phase 2 project and further infill wells in Jubilee Main

The Tullow working interest in the Jubilee field is 35.48% and the net Reserves attributed to Tullow are based on this working interest. The Jubilee Reserves at 31st December 2021 attributable to Tullow are presented in Table 2-2.

Reserves Category	Oil (MMstb)	Gas (Bscf)	Total Oil Equivalent (MMboe)
	2P	2P	2P
Developed Producing (DP)	65.8	63.1	76.3
Approved for Development (AD)	23.2	24.2	27.3
Justified for Development (JD)	32.4	51.6	41.0
Total Reserves	**121.4**	**138.9**	**144.6**

Table 2-2 Oil and gas Reserves for Jubilee field attributable to Tullow

2.2 TEN Fields

The TEN fields evaluated by TRACS consist of the Tweneboa, Enyenra and Ntomme fields.

The Tullow Reserves for the TEN fields are based on the following main components:

- Developed (on production) Reserves (DP) utilising the current wells for Enyenra and Ntomme.
- Approved for Development Reserves (AD) associated with Enyenra infill wells, Tweneboa/Ntomme development in the Riser Base area and development of Tweneboa gas to provide gas injection for Ntomme, all scheduled to be completed by end 2023
- Justified for Development Reserves (AD) associated with the further Axis development of Enyenra and Ntomme/Tweneboa Riser Base area. All activities to be completed by end 2025.

The Tullow working interest in the TEN fields is 47.175% and the net Reserves attributed to Tullow are based on this working interest. The TEN Reserves at 31st December 2021 attributable to Tullow are presented in Table 2-3.

Reserves Category	Oil (MMstb)	Gas (Bscf)	Total Oil Equivalent (MMboe)
	2P	2P	2P
Developed Producing (DP)	18.1	0.0	18.1
Approved for Development (AD)	11.5	0.0	11.5
Justified for Development (JD)	17.2	0.0	17.2
Total Reserves	**46.8**	**0.0**	**46.8**

Table 2-3 Oil and gas Reserves for the TEN fields attributable to Tullow

2.3 Gabon Fields

The Gabon fields evaluated by TRACS consist of Tchatamba Complex, Ezanga Complex, Oba field, M'Oba field, Turnix field, Echira field, Limande field, Niungo field and Simba field.

The Tullow Reserves for the Gabon assets are based on three main components:

- Developed (on production) Reserves utilising the current wells
- Approved for Development Reserves (AD) associated with identified workovers and infill wells that have been approved
- Justified for Development Reserves (JD) associated with identified workovers and infill wells

The Tullow working interest varies across the fields from 7.5% to 57.5% and the net Reserves attributed to Tullow are based on these working interests. The Gabon Reserves at 31st December 2021 attributable to Tullow are presented in Table 2-4.

Reserves Category	Oil (MMstb)
	2P
Developed Producing (DP)	28.4
Approved for Development (AD)	1.9
Justified for Development (JD)	2.5
Total Reserves	**32.8**

Table 2-4 Oil Reserves for the Gabon assets attributable to Tullow

There are no gas Reserves for the Gabon assets.

2.4 Côte d'Ivoire Fields

The Côte d'Ivoire fields evaluated by TRACS consist of the West Espoir and East Espoir fields.

The Tullow oil and gas Reserves for the Espoir fields are based on the following main components:

- Developed (on production) Reserves (DP) utilising the current wells for East and West Espoir
- Justified for Development Reserves (JD) associated with the remediation of the Espoir FPSO plus the Phase IV drilling campaign which targets further development of the East and West Espoir fields

No Approved for Development Reserves have been identified for the Espoir fields.

The Tullow working interest in the Espoir fields is 23.7% and the net revenue interest for Tullow is 21.33%. The net Reserves attributed to Tullow are based on the net revenue interest. The Côte d'Ivoire Reserves at 31st December 2021 attributable to Tullow are presented in Table 2-5.

Reserves Category	Oil (MMstb)	Gas (Bscf)	Total Oil Equivalent (MMboe)
	2P	2P	2P
Developed Producing (DP)	0.1	0.2	0.1
Approved for Development (AD)	0.0	0.0	0.0
Justified for Development (JD)	5.9	6.8	7.1
Total Reserves	**6.0**	**7.1**	**7.2**

Table 2-5 Oil and gas Reserves for the Côte d'Ivoire fields attributable to Tullow

3 General Methodology and Assumptions for Economics

Economics have been generated for the 2P total Reserves cases only. These have been generated at a field/asset level. An overview of the methodology used to generate the economics is given in the following sections.

3.1.1 Technical assessment

For all 2021 Reserves audits Tullow provided TRACS with production history, their decline analysis or forecasts, reservoir models and assumptions for current and new developments for the assets (where applicable). Also provided were development plans, historical costs and future cost assumptions, fiscal terms and statements regarding estimated Cessation of Production.

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

Technical production forecasts for 2P Reserves for input into the economic assessment are generated by model, decline analysis (DCA) or analytical estimates for existing wells and future planned well activity. Type curves have been generated either at well level, reservoir level or project level depending on the Reserves category. The type curves have been combined at field/asset level using an Excel based forecasting tool which honours field/asset constraints, production efficiency and project timing. Note that all oil and gas production that has been produced up to 31st December 2021 has been accounted for in the production forecasts and Reserves.

Life of field cost data was provided by Tullow including capital, fixed and variable operating and decommissioning costs. Tullow's cost estimates for producing assets that Tullow operate are based on historic data and operating experience. For new developments, the industry standard Que$tor Cost Estimating Tool was used by Tullow informed by Tullow's internal factors and norms. For non-operated assets Operator data was used.

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

3.1.2 Product price deck

The Nominal Brent 30-Trading Day Average based on the Brent ICE Futures Europe Strip for a determination date of the 31st December 2021 was used for the economic evaluation, as shown in the table below.

30-trading day average	2022	2023	2024	2025	2026
Nominal $/bbl Brent*	73.40	69.50	67.20	65.70	65.00
Real 2022 $/bbl Brent	73.40	68.14	64.59	61.91	60.05

* inflated at 2% per annum from 2026.

Crude quality differentials relative to Brent and adjustments for Domestic Supply Obligations were included where applicable.

All Jubilee gas exported post-Foundation is priced as per the Greater Jubilee Full Field Development Plan (GJFFDP), $2.35/MMBtu RT17. Tullow advised that the calorific value of Jubilee gas is 1280 Btu/scf.

TEN associated gas is sold at $0.5/MMBtu (RT13) and non-associated gas at $3.0/MMBtu (RT13). Tullow advised that the calorific value of TEN gas is 1157 Btu/scf.

The Espoir contract gas price is defined in the "Associated Natural Gas Sale and Purchase Agreement CI-26". Based on a calorific value of 1,058 Btu/scf the resulting gas price forecast is as follows.

	2022	2023	2024	2025	2026
Espoir gas price* ($/Mcf nominal)	6.48	7.78	7.46	7.26	7.14

* inflated at 2% per annum from 2026

None of the other assets have a sales gas stream.

3.1.3 Economic models

For each asset annual production, cost and price forecasts were used in annual increment economic spreadsheet model at a field level to calculate annual pre-tax and post-tax cash flows from a point forward date of 1 January 2022 to the cessation of production date (COP) date. The COP date is the earliest of the production license expiry date, facilities design lifetime, end of technical production profile or economic limit. The economic limit is defined as the year in which the Contractor cumulative pre-tax cash flow, post Royalty and excluding abandonment is at its maximum.

Calculations were based on the applicable Fiscal Regime/ PSC terms and current commercial arrangements. All economic spreadsheet models supplied by Tullow were reviewed by TRACS.

The cash flows were determined for the 2P Reserves case to assess the nominal post tax Net Present Value (NPV).

The Reserves/Resources are reported as Tullow working interest (attributable to Tullow) excluding fuel gas/oil and flare gas. A conversion rate of 6 MMscf/boe is assumed.

3.1.4 Base Case

NPV is reported at the Brent 30-Trading Day Average based on a determination date of the 31st December 2021 and a discount rate of 10% (NPV10), mid-year discounting.

3.1.5 Sensitivity Case

One sensitivity case has been evaluated:

- Total NPV10 including hedging.

4 Economic Results

4.1.1 Base Case

The total Tullow share NPV10 of the remaining 2P Reserves as at 31st December 2021 is $3,633MM.

The Tullow 2P Reserves remaining NPV10 is shown below for each country, Table 4-1. For assets operated under PSC terms the NPV is the Tullow Entitlement share, otherwise the working interest share is shown.

Country/Asset	**Tullow share NPV10 ($MM nom)**
	2P
Ghana/Jubilee	2824.4
Ghana/TEN	386.3
Gabon Total	389.6
Côte d'Ivoire Total	32.5
TOTAL	**3632.7**

Table 4-1 NPV10 Results for 2P Reserves

4.1.2 Impact of hedging on NPV 10

The Company has advised the value of its hedging portfolio. TRACS have not reviewed the company's hedging portfolio or its valuation.

As of 1 January 2022 and based on an assumed price deck of $73.4/bbl in 2022, $69.5/bbl in 2023 and $67.2/bbl in 2024 the values of the hedge portfolio are $(39.9)MM, $(34.9)MM and $(9.1)MM, respectively. The 10% discounted net present value as of 1 January 2022 is $(75.6)MM (negative).

The NPV10 of Tullow's 2P reserves, adjusted for the value of the hedge portfolio, is therefore $3557 MM.

5 Glossary of Terms

$	US Dollars
%	percent
°C	Degrees Celcius
2D	Two Dimensional
3D	Three Dimensional
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
Cali	Caliper
Capex	capital expenditure
CGR	Condensate Gas Ratio
cm^3	cubic centimetre
m^3	cubic metre
COCS	Chance of Commercial Success
E & A	Exploration & Appraisal
ft	feet
FTHP	Flowing Tubing Head Pressure
FWL	Free Water Level
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)
JV	Joint Venture
K	Permeability
km	Kilometre
km^2	Square kilometres
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
NFA	No Further Activity
NPV	Net Present Value
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
POS	Possibility Of Success
ppm wt	Parts per million by weight
PRMS	Petroleum Resource Management System
RROR	Real Rate of Return (from RT cashflows)
RT	Real Terms
SMT Kingdom	a PC-based interpretation workstation
SPE	Society of Petroleum Engineers
sq km	square kilometres
STOIIP	Stock Tank Oil Initially In Place
WI	Working Interest

Appendix A 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-1 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 A-1 Summary of 2018 SPE Petroleum Resources Classification

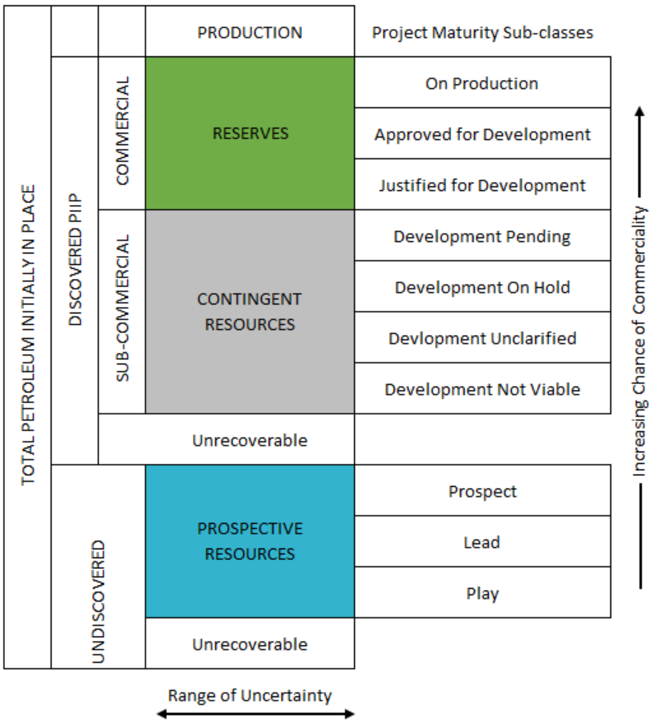

Table A-2 SPE PRMS Petroleum Resources Classification Framework