THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION. THIS DOCUMENT IS A CIRCULAR FOR THE PURPOSES OF LISTING RULE 13. IF YOU ARE IN ANY DOUBT AS TO WHAT ACTION YOU SHOULD TAKE, YOU ARE RECOMMENDED TO SEEK YOUR OWN PERSONAL FINANCIAL ADVICE IMMEDIATELY FROM YOUR STOCKBROKER, BANK MANAGER, SOLICITOR, ACCOUNTANT OR OTHER INDEPENDENT FINANCIAL ADVISER AUTHORISED UNDER THE FINANCIAL SERVICES AND MARKETS ACT 2000, OR FROM ANOTHER APPROPRIATELY AUTHORISED INDEPENDENT FINANCIAL ADVISER.

If you have sold or otherwise transferred all of your Tullow Shares, please send this document and the accompanying documents (other than documents or forms personalised for you) at once to the purchaser or transferee, or to the bank, stockbroker or other agent through whom the sale or transfer was effected, for delivery to the purchaser or transferee. However, these documents must not be forwarded, distributed or transmitted in, into or from any jurisdiction where to do so would violate the laws of that jurisdiction. If you have sold or otherwise transferred only part of your holding of Tullow Shares you should retain these documents and contact the bank, stockbroker or other agent through whom the sale or transfer was effected.

The release, publication or distribution of this document and/or the accompanying Form of Proxy in jurisdictions other than the United Kingdom may be restricted by law and, therefore, any persons who are subject to the laws of any jurisdiction other than the United Kingdom should inform themselves about, and observe, any applicable requirements. Any failure to comply with any such restrictions may constitute a violation of the securities laws of such jurisdictions. This document has been prepared for the purposes of complying with English law and the Listing Rules and the information disclosed may not be the same as that which would have been disclosed if this document had been prepared in accordance with the laws and regulations of any jurisdiction outside of England.

Tullow Oil plc

(incorporated and registered in England and Wales under the Companies Act 2006 with registered number 03919249)

Proposed sale of Tullow's entire stake in the Lake Albert Development Project in Uganda

Circular to Shareholders
and
Notice of General Meeting

This document should be read in its entirety and in conjunction with the accompanying Form of Proxy. Your attention, in particular, is drawn to the risk factors set out in Part II (*Risk Factors*) of this document and the letter from the Executive Chair of Tullow that is set out in Part I (*Letter from the Executive Chair of Tullow*) of this document and which contains the unanimous recommendation from the Directors that you vote in favour of the Resolution to be proposed at the General Meeting.

Notice of a General Meeting of Tullow to be held at the offices of Tullow Oil plc, at 9 Chiswick Park, 566 Chiswick High Road, London W4 5XT at 12 noon (London time) on 15 July 2020 is set out in Part IX (*Notice of General Meeting*) of this document. The actions to be taken in respect of the General Meeting are set out in Section 16 of Part I (*Letter from the Executive Chair of Tullow*) of this document. In light of the social distancing measures aimed at reducing the transmission of the COVID-19 virus in the United Kingdom, please note that **attendance at the General Meeting in person is not possible and Shareholders should instead vote in advance by proxy** by appointing the Chair of the General Meeting as their proxy in respect of all of their shares to vote on their behalf. Continued Shareholder engagement remains very important to the Company and Shareholders will therefore be able to listen to a live audio-cast of the General Meeting and submit questions remotely throughout, as was possible for the Company's 2020 Annual General Meeting. Shareholders may also submit questions in advance via ir@tullowoil.com. Detailed instructions about voting by proxy and accessing the audio-cast are set out in Part IX (*Notice of General Meeting*) of this document.

Whether participating in the audio-cast or not, Shareholders are strongly encouraged to appoint the Chair of the General Meeting as their proxy, by completing and signing the enclosed Form of Proxy or by appointing a proxy via CREST or online.

You will find enclosed with this document a Form of Proxy for the General Meeting. You are asked to complete the Form of Proxy in accordance with the instructions printed on it and return it to Tullow's Registrars: (i) in the UK, Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol, BS99 6ZY, as soon as possible and, in any event, so as to be received by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting; or (ii) in Ghana, The Central Securities Depository (Ghana) Limited, 4th Floor, Cedi House, P.M.B CT 465 Cantonments, Accra, Ghana, as soon as possible and, in any event, so as to be received by no later than 11.00 a.m. (local time) on 10 July 2020, being 72 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting.

CREST members who wish to appoint a proxy through the CREST electronic proxy appointment service may do so by using the procedures described in the CREST Manual and by logging on to the following website: www.euroclear.com. CREST personal members or other CREST sponsored members, and those CREST members who have appointed (a) voting service provider(s), should refer to their CREST sponsor or voting service provider(s) who will be able to take the appropriate action on their behalf. You must appoint a proxy through CREST by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting.

As an alternative to appointing a proxy using the Form of Proxy or CREST, members can appoint a proxy online at: www.investorcentre.co.uk/eproxy. In order to appoint a proxy using this website, members will need their Control Number, Shareholder Reference Number and PIN. You must appoint a proxy using the website by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting.

In addition, members who are institutional investors may be able to appoint a proxy electronically via the Proxymity platform, a process which has been agreed by the Company and approved by Computershare Investor Services PLC. For further information regarding Proxymity, please visit www.proxymity.io. You must appoint a proxy via Proxymity by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting. Before appointing a proxy via Proxymity, members will need to agree to Proxymity's associated terms and conditions. You should read such terms and conditions carefully as you will be bound by such terms and conditions, which will govern the electronic appointment of your proxy.

If you have any questions about this document, the General Meeting, the completion and return of the Form of Proxy or the appointment of a proxy through CREST or online, please call the shareholder helpline between 8:30 a.m. and 5:30 p.m. (London time) Monday to Friday (except UK public holidays) on +44 370 703 6242 (UK and other Shareholders) or +233 302 906 576 (Ghana Shareholders). Please note that calls may be monitored or recorded, and the helpline cannot provide financial, legal or tax advice or advice on the merits of the Transaction.

This document is not a prospectus and it does not constitute or form part of any offer or invitation to purchase, acquire, subscribe for, sell, dispose of or issue, or any solicitation of any offer to sell, dispose of, purchase, acquire or subscribe for, any security. This document is a circular relating to the Transaction, which has been prepared in accordance with English law and the Listing Rules and approved by the FCA.

Barclays Bank PLC, acting through its investment bank ("Barclays"), which is authorised in the UK by the PRA and regulated in the UK by the FCA and the PRA, is acting as joint financial adviser and joint sponsor exclusively for Tullow and no one else in connection with the Transaction and will not be responsible to anyone other than Tullow for providing the protections afforded to clients of Barclays, nor providing advice in relation to the Transaction or any other matters or arrangements referred to in this document.

J.P. Morgan Securities plc, which conducts its UK investment banking business as J.P. Morgan Cazenove ("J.P. Morgan Cazenove"), and which is authorised in the UK by the PRA and regulated in the UK by the FCA and the PRA, is acting as joint financial adviser and joint sponsor exclusively for Tullow and no one else in connection with the Transaction and will not regard any other person as its client in relation to the Transaction and will not be responsible to anyone other than Tullow for providing the protections afforded to clients of J.P. Morgan Cazenove or its affiliates, nor for providing advice in relation to the Transaction or any other matters or arrangements referred to in this document.

Robey Warshaw LLP ("Robey Warshaw"), which is authorised and regulated in the UK by the FCA, is acting as joint financial adviser exclusively for Tullow and no one else in connection with the Transaction and will not be responsible to anyone other than Tullow for providing the protections afforded to clients of Robey Warshaw, nor for providing advice in relation to the Transaction or any other matters or arrangements referred to in this document.

Apart from the responsibilities and liabilities, if any, which may be imposed on each of the Joint Financial Advisers by the FSMA or the regulatory regime established thereunder, or under the regulatory regime of any jurisdiction where the exclusion of liability under the relevant regulatory regime would be illegal, void or unenforceable, none of the Joint Financial Advisers, nor any of their respective subsidiaries, branches or affiliates, owes or accepts any duty, liability or responsibility whatsoever (whether direct or indirect, whether in contract, in tort, under statute or otherwise) for, and makes no representation or warranty, express or implied, as to the contents of this document, including its accuracy, completeness or verification or for any other statement made or purported to be made by them, or on their behalf, and nothing contained in this document is, or shall be, relied on as a promise or representation in this respect, whether as to the past or the future, in connection with Tullow or the Transaction. Save for the aforementioned responsibilities and liabilities, if any, each of the Joint Financial Advisers and their respective subsidiaries, branches and affiliates accordingly disclaims, to the fullest extent permitted by law, all and any duty, liability and responsibility whether arising in contract, in tort, under statute or otherwise (save as referred to above) in respect of this document or any such statement or otherwise.

The contents of the website of Tullow (www.tullowoil.com), any other website referred to in this document and any website directly or indirectly linked to such websites do not form part of (nor are otherwise incorporated into) this document and should not be relied upon.

Capitalised terms have the meaning ascribed to them in Part VIII (*Definitions*) of this document.

This document is dated 18 June 2020.

INFORMATION RELATING TO THE PRESENTATION AND SOURCES OF INFORMATION

INFORMATION REGARDING FORWARD-LOOKING STATEMENTS

This document includes statements that are, or may deemed to be, "forward-looking statements" within the meaning of the securities laws of certain jurisdictions. These forward-looking statements can be identified by the use of forward-looking terminology, such as "anticipate", "expect", "suggests", "plan", "believe", "intend", "estimates", "targets", "projects", "should", "could", "would", "may", "will", "forecast" and other similar expressions or, in each case, their negative or other variations or comparable terminology. These forward-looking statements include all matters that are not historical facts. They appear in a number of places throughout this document and include statements regarding Tullow's or the Directors' plans, estimates, intentions, beliefs or current expectations concerning, among other things, the Transaction, Tullow's exploration and development plans and the timing and cost thereof, future production levels and volumes, future operating cost levels, the grant and timing of future governmental or commercial or joint venture partner approvals or consents, future portfolio management plans, the Group's liquidity, financing costs and reserve base redeterminations, the timing, outcome and potential scope of liability in any litigation, proceedings or other disputes and Tullow's business, financial condition, results of operations and/or prospects and/or the industry in which the Group operates more generally.

Forward-looking statements are not guarantees of future performance and the Group's actual business, financial condition, results of operations and/or prospects and/or the development of the industry in which it operates, may differ materially from those made in or suggested by the forward-looking statements contained in this document. In addition, even if the Group's business, financial condition, results of operations and/or prospects and/or the development of the industry in which it operates, are consistent with the forward-looking statements contained in this document, those results or developments may not be indicative of results or developments in subsequent periods.

None of the Company, the Joint Financial Advisers nor any of its or their associates, directors, officers or advisers provides any representation, assurance or guarantee that the occurrence of the events expressed or implied in any forward-looking statements in this document will actually occur. You are cautioned not to place undue reliance on forward-looking statements because, by their nature, they involve known and unknown risks, uncertainties and other factors and relate to events and depend on circumstances that may or may not occur in the future that are in many cases beyond the control of the Group or, following Completion, the Retained Group.

The cautionary statements set forth above should be considered in connection with any subsequent written or oral forward-looking statements that the Company, or persons acting on its behalf, may issue. Factors that may cause the actual results of the Group and/or the Retained Group to differ materially from those expressed or implied by the forward-looking statements in this document include, but are not limited to, the risks described in Part II (*Risk Factors*) of this document.

Nothing in this section or anywhere else in this document should be construed as qualifying the statement in respect of the Retained Group's working capital set out in Section 13 of Part VI (*Additional Information*) of this document.

Any forward-looking statements that are made in this document speak only as at the date of such statement and, other than as may be required by the FCA, the London Stock Exchange, Euronext Dublin, the Ghana Stock Exchange or applicable law (including as may be required by the Listing Rules, the Disclosure Guidance and Transparency Rules and/or the Irish Listing Rules), Tullow and the Joint Financial Advisers expressly disclaim any obligation to release publicly any updates or revisions to any forward-looking statements contained in this document whether as a result of new information, future events or otherwise. Comparisons of results for current and any prior periods are not intended to express any future trends or indications of future performance, unless expressed as such, and should only be viewed as historical data.

NO PROFIT FORECAST

No statement in this document is intended or should be construed as a profit forecast or a profit estimate and no statement in this document should be interpreted to mean that earnings per Tullow Share for the current or future financial periods would necessarily match or exceed the historical published earnings per Tullow Share.

CURRENCIES

References to "£", "GBP", "pounds", "pounds sterling", "sterling", "p" and "pence" are to the lawful currency of the United Kingdom. References to "$", "US$", "USD", "$US", "US Dollars", "US dollars" or "cents" are to the lawful currency of the United States of America.

RESERVES AND RESOURCES

Except for oil and gas reserves data in relation to minor assets contributing less than five per cent. of the Group's reserves and unless otherwise indicated, the oil and gas reserves data presented in this document are audited by and have been estimated by TRACS International Limited ("TRACS"). TRACS is an independent reservoir evaluation company which has prepared its estimates in accordance with resource definitions jointly set out by the Society of Petroleum Engineers ("SPE"), the World Petroleum Council, the American Association of Petroleum Geologists and the Society of Petroleum Evaluation Engineers in June 2018 in the Petroleum Resources Management System ("PRMS").

In this document, references to "commercial reserves" are to 2P reserves, which is the sum of proved reserves plus probable reserves. Pursuant to the classifications and definitions provided by the PRMS, "proved reserves" are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 per cent. probability that the quantities actually recovered will equal or exceed the estimate. "Probable reserves" are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated aggregate of proved reserves and probable reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50 per cent. probability that the actual quantities recovered will equal or exceed the 2P estimate. "Possible reserves" are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than probable reserves. The total quantities ultimately recovered from a project have a low probability to exceed the aggregate of proved reserves, probable reserves and possible reserves (3P), which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10 per cent. probability that the actual quantities recovered will equal or exceed the 3P estimate.

In this document, references to "contingent resources" are to 2C resources. Pursuant to the classifications and definitions provided by the PRMS, 2C resources denote the best estimate scenario of contingent resources (being 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) which is defined as the most realistic assessment of recoverable quantities if only a single result were reported. If probabilistic methods are used, there should be at least a 50 per cent. probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

Unless otherwise indicated, all production figures are presented on a net basis to the Group's working interest basis. Where gross amounts are indicated, they are presented on a total basis (being the actual interest of the relevant licence holder in the relevant fields and licence areas without deduction for the economic interest of the Group's commercial partners, taxes or royalty interests or otherwise). The legal interest and effective working interest of the Group in the relevant fields and licence areas are disclosed separately in this document.

Hydrocarbon data

The mineral expert's report prepared by TRACS and set out in Part VII (*Mineral Expert's Report*) of this document (the "TRACS Report") uses the following estimates:

- oil in standard millions of barrels ("mmbbl") (a barrel being the equivalent of 42 US gallons);
- natural gas and natural gas liquids in billions of cubic feet ("bcf") at standard temperature and pressure bases; and
- liquid in standard millions of barrels of oil equivalent ("mmboe").

This document presents certain production and reserves related information on an "equivalency" basis. The conversion by the Company of data from tons into barrels and from cubic feet into mmboe may differ from that used by other companies. The Company has assumed a conversion rate of six bcf to one mmboe. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalencies at the wellhead. Although this conversion factor is an industry accepted convention, it is not reflective of price or market value differentials between product types.

There are a number of uncertainties inherent in estimating quantities of commercial reserves and contingent resources, including many factors beyond the Group's control.

The commercial reserves and contingent resources information on the Interests in the TRACS Report and commercial reserves and contingent resources information in respect of the Group and/or Retained Group (as applicable) represent only estimates and such estimates are forward-looking statements which are based on judgements regarding future events that may be inaccurate. Estimation of commercial reserves and contingent resources is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any commercial reserves or contingent resources estimate is a function of a number of factors, many of which are beyond the Group's control, including the quality of available data, and involves engineering and geological interpretation and judgement. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, due to the inherent uncertainties and the limited nature of reservoir data and the inherently imprecise nature of commercial reserves and contingent resources estimates, the initial commercial reserves and contingent resources estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Thus, investors should not place undue reliance on the ability of the commercial reserves and contingent resources information to predict actual commercial reserves and contingent resources or on comparisons of similar reports concerning other companies and this document should be accepted with the understanding that the Company's financial performance subsequent to the date of the estimates may necessitate revision of the commercial reserves and contingent resources information set forth herein. In addition, except to the extent that the Group acquires additional assets containing commercial reserves or conducts successful exploration and development activities, or both, its commercial reserves will decline as they are produced.

Investors should note that the TRACS Report has not estimated proved and probable reserves under the standards of reserves measurement applied by the U.S. Securities and Exchange Commission for any of the relevant periods reviewed in this document, or otherwise, which differ from PRMS.

Presentation in TRACS Report

TRACS has prepared assessments of the Group's asset base in respect of the Interests as at 13 March 2020 and presented its estimates of commercial reserves and contingent resources in the TRACS Report.

The technical personnel responsible for preparing the reserve estimates at TRACS meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the SPE. TRACS is an independent firm of petroleum engineers, geologists, geophysicists and petrophysicists. It does not own an interest in the Group's assets and is not employed on a contingent fee basis.

The TRACS Report was commissioned by the Company and was prepared specifically for the purposes of this document. So far as the Company is aware, no material changes have occurred since the date of the TRACS Report, the omission of which would make the TRACS Report misleading.

ROUNDING

Certain figures included in this document have been subject to rounding adjustments. Accordingly, figures shown in the same category presented in different tables may vary slightly and figures shown as totals in certain tables may not be an arithmetic aggregation of the figures that precede them.

PRESENTATION OF FINANCIAL INFORMATION

Unless otherwise stated, financial information relating to Tullow has been extracted without material adjustment from the audited consolidated financial statements of Tullow for the financial years ended 31 December 2019, 31 December 2018 and 31 December 2017.

Where information has been extracted from the audited consolidated financial statements of Tullow, the information is audited unless otherwise stated. Where information has been extracted from the unaudited management accounts of Tullow, the information is unaudited and has been prepared on a basis consistent with the accounting policies adopted in the Group's latest annual accounts, being those for the year ended 31 December 2019.

Unless otherwise indicated, financial information in this document relating to Tullow has been prepared in accordance with IFRS.

Pro forma financial information

In this document, any reference to "pro forma" financial information is to information which has been extracted without material adjustments from the unaudited pro forma financial information contained in Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document. The unaudited pro forma financial information is presented in millions of US Dollars. The unaudited pro forma financial information has been prepared to illustrate the effect on the net assets of the Retained Group as if the Transaction had taken place on 31 December 2019.

The unaudited pro forma financial information has been prepared for illustrative purposes only and, because of its nature, addresses hypothetical situations and does not, therefore, represent Tullow's or the Retained Group's actual financial position or results. The unaudited pro forma financial information has been prepared under IFRS as adopted by the EU and on the basis set out in Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document and in accordance with Annex 20 of the PR Regulation. The pro forma financial information is stated on the basis of the accounting policies of Tullow Oil plc.

Non-IFRS measures

Net Debt is a useful indicator of the Group's indebtedness, financial flexibility and capital structure because it indicates the level of cash borrowings after taking account of cash and cash equivalents within the Group's business that could be utilised to pay down the outstanding cash borrowings. "Net Debt" as referred to in this document is defined as set out in the Group's latest annual accounts, being those for the year ended 31 December 2019, and means current and non-current borrowings plus non-cash adjustments, less cash and cash equivalents. Non-cash adjustments include unamortised arrangement fees, adjustment to convertible bonds, and other adjustments. The Group's definition of Net Debt does not include the Group's leases as the Group's focus is the management of cash borrowings and a lease is viewed as deferred capital investment. This definition of Net Debt should be distinguished from the definition of Covenanted Net Debt in respect of the RBL Gearing Covenant under the RBL Facility (described in Section 19 of Part I (*Letter from the Executive Chair of Tullow*) of this document).

Gearing is a useful indicator of the Group's indebtedness, financial flexibility and capital structure and can assist securities analysts, investors and other parties to evaluate the Group. "Gearing" as referred to in this document is defined as set out in the Group's latest annual accounts, being those for the year ended 31 December 2019, and means Net Debt divided by Adjusted EBITDAX. "Adjusted EBITDAX" is defined as profit/(loss) from continuing activities adjusted for income tax (expense)/credit, finance costs, finance revenue, gain on hedging instruments, depreciation, depletion and amortisation, share-based payment charge, restructuring costs, gain/(loss) on disposal, exploration costs written off, impairment of property, plant and equipment net, and provision for onerous service contracts. Adjusted EBITDAX therefore excludes interest on obligations under leases, and interest income on amounts due from joint venture partners for finance leases, as in assessing business performance, management considers lease payments in substance to represent deferred capital expenditure. These concepts of Net Debt, Gearing and Adjusted EBITDAX should be distinguished from the concepts of Covenanted Net Debt and Consolidated EBITDA used to determine compliance with the RBL Gearing Covenant under the RBL Facility (as described in Section 19 of Part I (*Letter from the Executive Chair of Tullow*) of this document).

The following reconciliation tables have been extracted from Tullow's annual report and accounts for the financial year ended 31 December 2019.

Calculation of Net Debt for the Group as at 31 December 2019

Non-current borrowings (US$m)	3,071.7
Non-cash adjustments (US$m)	22.6
Less cash and cash equivalents (US$m)	(288.8)
Net Debt (US$m)	2,805.5

Calculation of Adjusted EBITDAX for the Group as at 31 December 2019

(Loss)/profit from continuing activities (US$m)	(1,694.1)
Adjusted for:	
Income tax expense (US$m)	40.7
Finance costs (US$m)	322.3
Finance revenue (US$m)	(55.5)
Loss/(gain) on hedging instruments (US$m)	1.5
Depreciation, depletion and amortisation (US$m)	724.6
Share-based payment charge (US$m)	25.8
Provisions (US$m)	4.2
Gain on disposal (US$m)	(6.6)
Exploration costs written off (US$m)	1,253.4
Impairment of property, plant and equipment, net (US$m)	781.2
Adjusted EBITDAX (US$m)	1,397.5

Calculation of Net Debt/Adjusted EBITDAX Gearing of the Group as at 31 December 2019

Net Debt (US$m)	2,805.5
Adjusted EBITDAX (US$m)	1,397.5
Gearing	2.0

CONTENTS

EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Announcement of the Transaction	23 April 2020
Publication of this document	18 June 2020
Latest time and date for receipt of Forms of Proxy for the General Meeting by Tullow's Registrar in Ghana	11.00 a.m. on 10 July 2020 (local time)(1)
Latest time and date for receipt of Forms of Proxy for the General Meeting by Tullow's Registrar in the UK	12 noon on 13 July 2020(1)
Latest time and date for receipt of CREST Proxy Instructions for the General Meeting	12 noon on 13 July 2020(1)
Latest time and date for completion of online proxy appointment for the General Meeting	12 noon on 13 July 2020(1)
Voting record time for the General Meeting	6.00 p.m. on 13 July 2020(2)
General Meeting	12 noon on 15 July 2020(3)
Expected timing of Completion of the Transaction	Second half of 2020
Long stop date for satisfaction of Transaction conditions	23 October 2020(4)

All time references in this document are to London time unless otherwise stated.

These dates are provided by way of indicative guidance only and are subject to change. If any of the above times and/or dates change, the new times and/or dates will be notified to Shareholders by an announcement through an RIS.

Completion of the Transaction is conditional upon the fulfilment or waiver of various conditions, including approval of the Resolution by Shareholders, approval of the Minister of Energy and Mineral Development of the Republic of Uganda in respect of the Transaction and entering into the Tax Agreement with the Government of Uganda and the URA. There can be no certainty if or when such conditions will be fulfilled and therefore no certainty as at the date of this Circular regarding the date of Completion.

Notes

(1) In order to be valid if the General Meeting is adjourned, the Form of Proxy must be received by post, or the CREST Proxy Instruction must be received, or the online proxy appointment must be completed, no later than 48 hours (excluding any part of a day that is not a working day) before the time set for such adjourned meeting (except for Forms of Proxy posted to The Central Securities Depository (Ghana) Limited, 4th Floor, Cedi House, P.M.B CT 465 Cantonments, Accra, Ghana, which must be received no later than 72 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting). Please see Section 16 of Part I (*Letter from the Executive Chair of Tullow*) of this document.

(2) If the General Meeting is adjourned, the voting record time for the adjourned meeting will be 6.00 p.m. (London time) on the day which is two days (excluding non-working days) prior to the date set for such adjourned meeting.

(3) The General Meeting will be held at the offices of Tullow Oil plc, at 9 Chiswick Park, 566 Chiswick High Road, London W4 5XT.

(4) Unless the parties to the Sale and Purchase Agreement mutually agree to extend such date.

DIRECTORS, COMPANY SECRETARY, REGISTERED OFFICE AND ADVISERS

Directors of Tullow	Dorothy Thompson CBE	Executive Chair
	Les Wood	Chief Financial Officer
	Jeremy Wilson	Senior Independent Non-Executive Director
	Mike Daly	Independent Non-Executive Director
	Sheila Khama	Independent Non-Executive Director
	Genevieve Sangudi	Independent Non-Executive Director
	Martin Greenslade	Independent Non-Executive Director

Company Secretary of Tullow . . . . Adam Holland

Registered Office of Tullow . . . .
9 Chiswick Park
566 Chiswick High Road
London W4 5XT

Joint Financial Advisers and Joint Sponsors . . . . .
Barclays Bank PLC, acting through its investment bank
5 The North Colonnade
Canary Wharf
London E14 4BB

J.P. Morgan Securities plc
(which conducts its UK investment banking business as J.P. Morgan Cazenove)
25 Bank Street
Canary Wharf
London E14 5JP

Joint Financial Adviser . .
Robey Warshaw LLP
9 Grosvenor Square
London W1K 5AE

English Legal Adviser to the Company . . . .
Freshfields Bruckhaus Deringer LLP
65 Fleet Street
London EC4Y 1HS

English Legal Adviser to the Joint Sponsors . . . . .
Ashurst LLP
Fruit & Wool Exchange
1 Duval Square
London E1 6PW

Reporting Accountants and Auditors . . . .
Deloitte LLP
Hill House
2 New Street Square
London EC4A 3BZ

Reserves and Resources Auditors . . . .
TRACS International Limited
East Wing First Floor
Admiral House
Poynernook Road
Aberdeen AB11 5QX

Registrars . . . . Computershare Investor Services PLC
The Pavilions
Bridgwater Road
Bristol BS99 6ZY

The Central Securities Depository (Ghana) Limited
4th Floor
Cedi House
P.M.B CT 465 Cantonments
Accra
Ghana

PART I—LETTER FROM THE EXECUTIVE CHAIR OF TULLOW

TULLOW OIL PLC

(Incorporated and registered in England and Wales with registered number 03919249)

Directors:		*Registered Office:*
Dorothy Thompson CBE	(*Executive Chair*)	9 Chiswick Park,
Les Wood	(*Chief Financial Officer*)	566 Chiswick High Road,
Jeremy Wilson	(*Senior Independent Non-Executive Director*)	London,
Mike Daly	(*Independent Non-Executive Director*)	W4 5XT
Sheila Khama	(*Independent Non-Executive Director*)	
Genevieve Sangudi	(*Independent Non-Executive Director*)	
Martin Greenslade	*(Independent Non-Executive Director)*	

18 June 2020

Dear Shareholder

Proposed sale of Tullow's entire stake in the Lake Albert Development Project in Uganda and Notice of General Meeting

1. Introduction

On 23 April 2020, the Company announced that Tullow Uganda and Total Uganda had signed a Sale and Purchase Agreement, with an effective date of 1 January 2020 (the "Effective Date"), in which it agreed to transfer its entire interests in Blocks 1, 1A, 2 and 3A in Uganda and the proposed East African Crude Oil Pipeline (EACOP) System to Total for cash consideration of US$575 million plus potential contingent payments after first oil (the "Transaction").

The cash consideration consists of US$500 million payable at Completion and US$75 million payable following the final investment decision for the Lake Albert Development Project. Once production commences, additional cash consideration may be received by Tullow Uganda in the form of contingent payments which will be payable on upstream revenues from the Lake Albert Development Project, depending on the average annual Brent price.

Tullow and Total had positive and supportive discussions with both the Government of Uganda and the Uganda Revenue Authority (the "URA") prior to the Transaction Announcement and agreed the principles of the tax treatment of the Transaction. This includes the expected position on Ugandan capital gains tax, which will be remitted by Total Uganda on behalf of Tullow Uganda. Tullow Uganda and Total Uganda intend to sign a binding tax agreement with the Government of Uganda and the URA that reflects these principles which will enable Completion to occur.

The Transaction will strengthen Tullow's balance sheet as part of its financial strategy to move to a more conservative capital structure. Tullow's capital expenditure in respect of the Interests between the Effective Date and Completion will be recovered through the Sale and Purchase Agreement completion adjustments. The Transaction will remove all future capital expenditure associated with the Lake Albert Development Project whilst retaining exposure via contingent payments linked to production and the oil price through the contingent cash consideration described above.

The Group is currently operator of Block 2. On Completion, the Group will resign as operator of Block 2 and Total Uganda will be appointed as operator of Block 2. Total Uganda is currently operator of Block 1 and Block 1A and CNOOC Uganda is operator of Block 3A.

Completion of the Transaction will result in the Company no longer holding any material assets in Uganda. Subject to the satisfaction of the conditions to the Transaction, the Transaction is expected to complete in the second half of 2020.

Under the UK Listing Rules, the Transaction constitutes a Class 1 transaction and is therefore conditional on the approval of the Shareholders, by a simple majority of votes cast, at the General Meeting, notice of which is set out at the end of this document. Prior to the Transaction Announcement, Tullow consulted with

Shareholders holding approximately 27.5 per cent. in aggregate of Tullow's issued share capital at that time and reported in the Transaction Announcement that such Shareholders indicated their support for the Transaction.

The purpose of this document is to: (i) explain the background to and reasons for the Transaction; (ii) provide information about the Interests; (iii) explain why the Directors unanimously consider the Transaction is in the best interests of the Company and the Shareholders as a whole; and (iv) recommend that you vote in favour of the Resolution to be proposed at the General Meeting, particularly in light of the Group's working capital position as described further below.

2. Background to and reasons for the Transaction

In light of developments in 2019, Tullow initiated a Business Review, involving a thorough reassessment of the Group's organisation structure, cost base, future investment and asset portfolio plans.

Net Debt reduction remains a priority and a key aspect of the Business Review has been focused on achieving this in the near to medium term through portfolio management, of which the Transaction is part, to deliver a more conservative capital structure. The outcome of this ongoing Business Review is also intended to ensure that: (i) the Group's costs are more appropriate for the size and shape of Tullow's business; (ii) the reduced 2020 capital expenditure level is being allocated appropriately to the Group's producing assets, development projects and future exploration; and (iii) the Group's operating costs are competitive relative to industry standards.

Since Tullow's announcement in December 2019 of Board changes and revisions to 2020 guidance, Tullow has, amongst other things, been focused on delivering reliable production, lowering its cost base and exploring portfolio management options to reduce Net Debt and strengthen its balance sheet. On 12 March 2020, Tullow's Board announced its plans to raise in excess of US$1 billion of proceeds from portfolio management in order to further streamline the business and to reduce Gearing. The Transaction represents the first significant step in raising these proceeds.

Completion of the Transaction will enable Tullow to realise value from the Lake Albert Development Project, following the expiry of its previous farm-down agreement with Total Uganda and CNOOC Uganda in August 2019. Having evaluated alternatives for the Lake Albert Development Project and having discussed its future with both of Tullow's joint venture partners and the Government of Uganda, Tullow's Board and senior management believe that the Transaction represents an attractive outcome for the Group.

3. Summary of the terms of the Transaction

In the Transaction Announcement, Tullow announced that the Sale and Purchase Agreement, with an Effective Date of 1 January 2020, had been signed on 23 April 2020 in which Tullow Uganda Limited and Tullow Uganda Operations Pty Ltd. (together, "Tullow Uganda") have agreed to transfer to Total E&P Uganda B.V. ("Total Uganda") for cash consideration the entirety of Tullow's interests in each of the assets comprising the Lake Albert Development Project (the "Interests"), being: (i) a 33.3334 per cent. interest in the production sharing agreements for each of Block 1, 1A, 2 and 3A in Uganda and the licences and certain other contracts related thereto (the "Upstream Segment"); and (ii) its interests in the proposed EACOP System (the "Midstream Segment").

The Sale and Purchase Agreement is based on the transfer of interests from Tullow Uganda to Total Uganda in exchange for cash at completion, deferred consideration to be paid as and when the Upstream Segment and Midstream Segment of the Lake Albert Development Project reach final investment decision and contingent payments determined on the basis of future oil prices.

The total consideration for the Transaction payable by Total Uganda is structured as follows: (i) US$575 million in cash, consisting of US$500 million payable on Completion (subject to customary adjustments) and US$75 million payable following the final investment decision of the Upstream Segment and the Midstream Segment; and (ii) contingent annual payments to be paid on upstream revenues from the Interests (reducing to 28.3334 per cent. following the exercise by Uganda National Oil Company ("UNOC") of its back-in rights) at a rate of 0 per cent. if the average annual Brent price is less than or equal to US$62/bbl, 1.25 per cent. (net of tax) if the average annual Brent price is greater than US$62/bbl or 2.5 per cent. (net of tax) if the average annual Brent price is greater than US$70/bbl. Total Uganda will also reimburse joint venture costs incurred and paid by Tullow Uganda from the Effective Date to Completion in respect of the Interests.

The Transaction is classified as a Class 1 transaction as defined by Chapter 10 of the UK Listing Rules. As such, it is conditional on the approval of the Shareholders, by a simple majority of votes cast, at the General Meeting, notice of which is set out at the end of this document.

Completion of the Sale and Purchase Agreement is also subject to a number of other conditions, including:

- the signing of the Tax Agreement by the URA and the Government of Uganda that reflects the agreed principles of the tax treatment of the Transaction; and
- the approval of the Minister of Energy and Mineral Development of the Republic of Uganda in respect of: (i) the transfer of the Upstream Segment; and (ii) the transfer of operatorship of Block 2, as required under the applicable production sharing agreements and Ugandan law (the "Minister Consents"), in each case to Total Uganda.

Completion was also subject to CNOOC Uganda having declined to exercise its pre-emption rights under each of the Joint Operating Agreements or, where CNOOC Uganda had exercised its pre-emption rights with respect to the Upstream Segment, Tullow Uganda and Total Uganda (each acting reasonably) having agreed amendments to the Sale and Purchase Agreement and other arrangements to reflect the exercise of such pre-emption rights. On 26 May 2020, CNOOC Uganda gave notice that it did not wish to exercise its pre-emption rights.

The Company has undertaken to use all reasonable endeavours to procure that the approval of the Shareholders is obtained. The parties have undertaken to use (i) all reasonable endeavours to procure the satisfaction of the condition relating to the signing of the Tax Agreement as soon as practicable, and (ii) reasonable endeavours to procure that each of the other conditions is satisfied as soon as possible after the signing date of the Sale and Purchase Agreement and in any event by 23 October 2020 (unless the parties mutually agree to extend such date).

A binding tax agreement is intended to be entered into between Tullow Uganda, Total Uganda, the URA and the Government of Uganda (acting through the Ministry of Energy and Mineral Development and the Ministry of Finance, Planning and Economic Development) (the "Tax Agreement"). It is expected that the Tax Agreement will reflect the agreed principles of the tax treatment of the Transaction as follows: (i) fixed consideration (being US$575 million) will be subject to Ugandan tax on capital gains of US$14.61 million, to be remitted by Total Uganda on behalf of Tullow Uganda; and (ii) any contingent consideration will also be subject to Ugandan tax on capital gains at 30 per cent., also to be remitted by Total Uganda on behalf of Tullow Uganda. The URA and Government of Uganda entering into the Tax Agreement is a condition precedent to Completion. Total Uganda and Tullow Uganda have certain Sale and Purchase Agreement termination rights in the event that the Tax Agreement, once entered into, is challenged, revoked or there is a threat to do so.

Total Uganda has the right to terminate the Sale and Purchase Agreement between signing and Completion in certain circumstances if there is a material adverse event, which includes: (i) a breach of fundamental warranty by Tullow Uganda; (ii) any action or claim by a third party seeking to restrain or materially alter the transactions contemplated by the Sale and Purchase Agreement; or (iii) an event or series of related events occurring in Uganda, where each of (i), (ii) or (iii) results in a reduction in the value of the Interests in excess of US$86.25 million (and in each case certain macro-events such as changes in hydrocarbon prices, market conditions and COVID-19 are excluded); or (iv) an insolvency event in respect of the Company, Tullow Uganda or any holding company of Tullow Uganda.

Tullow Uganda and Total Uganda each has the right to terminate the Sale and Purchase Agreement between signing and Completion: (i) if the URA or any other Ugandan Government Authority challenges or revokes or purports to revoke or threatens to revoke the Tax Agreement once entered into; (ii) if there is a breach of specific warranties and undertakings given in respect of anti-bribery and corruption; or (iii) if any of the conditions precedent to Completion are not satisfied or waived by 23 October 2020 (unless the parties mutually agree to extend such date).

Further information regarding the terms of the Transaction is set out in Part V (*Summary of the Principal Terms of the Transaction*) of this document.

4. Pre-emption rights in respect of the Transaction

Pursuant to the terms of the Joint Operating Agreements, CNOOC Uganda had rights of pre-emption to acquire 50 per cent. of the Upstream Segment on the same terms and conditions as Total Uganda under the Sale and Purchase Agreement.

Following the Transaction Announcement, the Company informed CNOOC Uganda of the Transaction and offered CNOOC Uganda the opportunity to exercise its rights to acquire 50 per cent. of the Upstream Segment.

On 26 May 2020, CNOOC Uganda gave notice that it did not wish to exercise its pre-emption rights.

5. Use of proceeds and financial effects of the Transaction

The net proceeds from the Transaction will be used to reduce Net Debt, strengthening Tullow's balance sheet, reducing ongoing financing costs and moving Tullow towards a more conservative capital structure.

On a pro forma basis, the Retained Group's Net Debt as at 31 December 2019, if Completion had occurred on that date, would have been approximately US$2.3 billion and the Retained Group's Gearing would have been approximately 1.7 times Net Debt/Adjusted EBITDAX. The financial information set out in this paragraph is unaudited and is calculated as described in Note 9 of the unaudited pro forma financial information contained in Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document.

As previously announced, Tullow is now targeting capital expenditure of approximately US$300 million in 2020 (down from approximately US$350 million). Savings have been identified primarily through the deferral of activities across the portfolio and through savings that can be realised by ongoing farm-down activities. Once Completion occurs, capital expenditure will reduce by a further US$15 million approximately for 2020 and the exit from the Lake Albert Development Project will remove all future capital expenditure associated with the Interests.

There was an operating loss of US$528.8 million associated with the Interests for the year ended 31 December 2019, comprising administrative expenses and exploration costs written off for such period that are not taken into account in the Group's gross profit. However, because there are no earnings attributable to the Interests, there would have been no impact on the Group's gross profit for the year ended 31 December 2019 had the Transaction completed on that date, with there being no gross profits attributable to the Interests for the year ended 31 December 2019. Had the Transaction completed on 31 December 2019, the Group's gross assets would have, before receipt of cash proceeds, reduced by US$992.2 million, being the gross asset amount of the Interests as at 31 December 2019, as set out in Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document. The financial information set out in this paragraph has been extracted without material adjustment from the consolidation schedules and supporting analysis that underlie Tullow's audited consolidated financial statements as at and for the year ended 31 December 2019.

6. Taxation of the Transaction

Tullow and Total have discussed and agreed the principles of the tax treatment of the Transaction with the URA and the Government of Uganda (acting through the Ministry of Energy and Mineral Development and the Ministry of Finance, Planning and Economic Development). In light of those discussions, it is expected that the Transaction will be subject to the following Ugandan tax treatment:

- a capital gain of US$48.715 million will arise on Completion, subject to Ugandan tax on capital gains at 30 per cent. being US$14.61 million, which will be remitted by Total Uganda on behalf of Tullow Uganda; and
- any contingent consideration paid to Tullow will represent a capital gain in relation to the Transaction, subject to Ugandan tax on capital gains at 30 per cent. This tax will also be remitted by Total Uganda on behalf of Tullow Uganda.

Tullow Uganda and Total Uganda intend to enter into the Tax Agreement with the Government of Uganda and the URA to reflect these principles to enable Completion to occur. The URA and Government of Uganda entering into the Tax Agreement is a condition precedent to Completion. Total Uganda and Tullow Uganda have certain Sale and Purchase Agreement termination rights in the event that the Tax Agreement, once entered into, is challenged, revoked or there is a threat to do so.

7. Current trading and prospects

Tullow announced its full year results for the year ended 31 December 2019 on 12 March 2020. In these results, the Directors assessed that the Group was a going concern for 12 months from the date of approval of Tullow's annual report and accounts for the financial year ended 31 December 2019. At the time of issuing Tullow's annual report and accounts for the financial year ended 31 December 2019, there were unprecedented market conditions relating to COVID-19 and the oil price, as described in Section 8 (*Industry update*) below. These conditions increased the risk that the Group may not be able to sufficiently progress planned portfolio management activities, as a result of which its lenders may not approve the bi-annual RBL Facility redetermination liquidity assessments or covenant amendments if subsequently required. Therefore, the Directors concluded that there is a material uncertainty, that may cast significant doubt, that the Group will be able to operate as a going concern. Although this material uncertainty remains in place, this Transaction represents part of the mitigating actions available to the Group and the Directors recognise that further portfolio management beyond this Transaction will be required to remove this material uncertainty.

As described in Section 8 (*Industry Update*) below, oil prices have increased from their lows in March and April 2020 to approximately US$40/bbl on 3 June 2020 as a result of the OPEC+ extension of supply reductions and the increase in demand as the global COVID-19 lockdown measures have been gradually relaxed. Whilst there remains significant uncertainty as to how sustainable the recovery in oil prices will be going forward, the Directors recognise that a sustained improvement in the oil price would provide some support to the financial position of the Group as it continues to explore portfolio management and other mitigating actions beyond this Transaction. However, the overall reduction in oil price since the end of the 2019 financial year could give rise to impairment in the Group's reported values held as at 30 June 2020 in respect of its non-current assets, in particular "Property, Plant and Equipment" and "Intangible Exploration and Evaluation Assets".

As announced on 3 April 2020, Tullow completed the March 2020 RBL Facility redetermination with US$1.9 billion of debt capacity approved by the lending syndicate. As a result, Tullow had approximately US$700 million liquidity headroom of undrawn facilities and free cash at the start of the second quarter of the year.

Tullow's assets remain solid, supported by: (i) material underlying reserves and resources and a strong production base in West Africa; (ii) an onshore development project in Kenya where Tullow had been working with partners to progress field development (but where Tullow and its partners have called force majeure (as a result of the impact of the COVID-19 pandemic on Tullow's work programme and the effect recent tax laws changes have on the partners' ability to meet their obligations under the licences) to allow time both for the restrictions on the work programme to lift and for the partners and the Kenyan government to discuss the fiscal incentives required to make this project viable); and (iii) an exploration portfolio in Africa and South America.

With Group production in the first quarter of 2020 averaging 75,800 bopd, the Group continues to produce from its West African operations in line with its full year production forecasts. In Ghana, Government exemptions have been granted to allow charter flights for oil and gas workers into the country, enabling crew changes to occur. Tullow is then requiring all personnel to self-isolate in Ghana for two weeks before transferring to its FPSOs to minimise the risk of a COVID-19 outbreak offshore. While there have been cases of COVID-19 reported offshore in Ghana (including on both the Jubilee and TEN FPSOs), as at the Latest Practicable Date there are no known cases onboard either of Tullow's operated FPSOs and mitigation plans are in place to allow production to continue uninterrupted.

At the TEN field, the Nt-09 well, which was due to start producing in June 2020, is now expected to come onstream in August 2020 due to a delay in completing the well. This delay is not expected to materially affect the Group's full year production and capital expenditure forecasts due to good production performance and further capital savings identified across the portfolio.

As of 31 May 2020, Tullow had approximately 60 per cent. of its 2020 sales revenue hedged with a floor of approximately US$57/bbl and approximately 40 per cent. of its 2021 sales revenue hedged with a floor of approximately US$53/bbl. Tullow's realised oil price for the five months ended 31 May 2020 was approximately US$52/bbl including the benefit of approximately US$111 million of net hedge receipts during the period. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

As announced on 21 April 2020, Rahul Dhir has been appointed as Chief Executive Officer and an Executive Director of the Group from 1 July 2020. Mr Dhir will join Tullow from Delonex Energy, where he was CEO of the Africa-focused oil and gas company. Prior to Delonex, Mr Dhir served as Managing Director and CEO of Cairn India.

8. INDUSTRY UPDATE

In recent months, the oil and gas industry has witnessed an unprecedented double shock, with a sharp supply increase from OPEC+ members as a result of a breakdown in OPEC+ supply restrictions that had been in place since January 2019 occurring at the same time as a collapse in demand due to the rapid global spread of COVID-19 and subsequent strict travel restrictions implemented by governments internationally, causing severe dislocation in global oil markets. The International Energy Agency reported that, because of the lockdown measures, global oil demand fell by 10.8 mmbl/d year-on-year in March 2020, while also forecasting a drop in demand as large as 20 mmbl/d year-on-year for the second half of 2020 and 8.6 mmbl/d year-on-year for 2020 because of COVID-19.

On 14 April 2020, OPEC+ and non-OPEC nations announced a renewed agreement with reductions in OPEC+ supply of 9.7 mmbl/d effective from 1 May 2020. The agreement stated that OPEC+ expects total global oil cuts to reach as much as 20 mmbl/d, with G20 and other oil-producing nations contributing by strategic petroleum reserve purchases or natural production reductions. The agreement stated that the OPEC+ reductions would be in place until 2022 and revisited at subsequent OPEC+ meetings. At the June 2020 OPEC+ meeting, the previously agreed supply cuts were extended in their entirety by one month, to July 2020. With the OPEC+ agreement taking effect along with production shut-ins by independent producers, estimates of global supply have been significantly revised down, with the U.S. Energy Information Administration forecasting a fall in global oil supply by 7.9 mmbl/d for the second quarter of 2020. This drop in supply combined with a gradual recovery in demand due to the relaxation of the strictest COVID-19 lockdown measures globally resulted in a steady recovery in the price of Brent throughout May 2020, with the ICE Brent Near Term contract reaching US$40/bbl on 3 June 2020 (compared to an average price of US$34/bbl in March, US$27/bbl in April and US$32/bbl in May 2020 and compared to an average price of US$64/bbl in 2019).

Uncertainty over the impact of COVID-19 on demand has resulted in varied estimates over the speed of recovery in international oil and gas markets. This disruption to the energy markets was magnified by depleting storage capacity concerns, with an estimated 85 per cent. of global onshore storage full as of late April. Additionally, whereas previous volatility has had minimal impact on the back end of the forward curve, the severe changes to the market have resulted in forward prices for Brent reducing by US$5-10/bbl, with the 2023 forward contract trading at $47/bbl on 29 May 2020 compared to US$54/bbl on 6 March 2020.

9. Profile and strategy for the Retained Group

The Company is a well-established and recognised oil and gas explorer and producer operating across Africa and South America. Following Completion of the Transaction, the Company will continue to focus on finding and monetising oil in Africa and South America through targeted exploration and appraisal activities and selective development projects to grow its low-cost production base.

The Company will continue to focus on delivering low-cost production from its assets in West Africa in order to achieve robust and sustainable cash flows. The Business Review has identified significant savings that could be achieved by making the Company a more efficient and effective organisation. At present, the Company is targeting net general and administrative expenses savings of approximately US$200 million over the three financial years ending 31 December 2020, 31 December 2021 and 31 December 2022, delivered through a number of efficiency measures, including office closures. The Company targets a headcount reduction of at least 35 per cent. by 31 December 2020 and is also looking into redesigning processes including business planning and operational forecasting.

The outcome of the ongoing Business Review is intended to ensure that: (i) the Group's costs are more appropriate for the size and shape of Tullow's business; (ii) the reduced 2020 capital expenditure level is being allocated appropriately to the Group's producing assets, development projects and future exploration; and (iii) the Group's operating costs are competitive relative to industry standards.

The Company aims to maintain a prudent financial strategy with diverse sources of funding. Debt reduction will remain a priority, with portfolio action remaining central to delivering a more conservative capital structure. The Transaction represents the first significant step in raising in excess of US$1 billion of proceeds from portfolio management, in order to further streamline the business and reduce Net Debt. The Board announced in December 2019 its decision to suspend the Company's dividend payment.

Ordinarily, the Company actively hedges its exposure to oil prices and it has a policy of hedging its expected sales volumes on a graduated two-year rolling basis with the aim to ensure that 60 per cent. of its expected production for the current calendar year and 30 per cent. of its expected production for the following calendar year is hedged. However, as a result of the prevailing low forward prices for Brent oil, the Company ceased to enter into new hedging contracts on 25 February 2020. The Company intends to recommence its hedging programme when forward prices for Brent oil have recovered sufficiently to support the objectives of the Company's hedging strategy. As of 31 May 2020, Tullow had approximately 60 per cent. of its 2020 sales revenue hedged with a floor of approximately US$57/bbl and approximately 40 per cent. of 2021 sales revenue hedged with a floor of approximately US$53/bbl. Liquidity risk will also continue to be monitored closely through cash flow forecasts and sensitivity analyses. The Company will also continue to manage credit risk by assessing the creditworthiness of potential counterparties before entering into transactions with them, and by continuing to evaluate their creditworthiness after transactions have been initiated. Further, the Company intends to maintain insurance policies in line with customary industry practices, including business interruption insurance to protect against loss of production from its material assets.

Maintaining and growing production remains key to the Company's strategy and, following Completion, the Company will retain a number of attractive rate-of-return development opportunities that it expects will strengthen its cash flow and will grow its commercial reserves. These include infill drilling opportunities at the Jubilee and TEN fields as well as drilling opportunities in its non-operated portfolio. Selective exploration activity for high-margin, low-cost oil in conventional geological core plays where the Company has proven expertise will also continue to form part of its growth strategy. To deliver this, the Company will continue to manage its financial exposure in exploration licences with portfolio monetisation initiatives undertaken at appropriate points in the early-life cycle of its exploration assets.

10. Information on the Interests

The Interests that Tullow Uganda has agreed to transfer to Total Uganda comprise the entirety of Tullow's interests in each of the assets comprising the Lake Albert Development Project, comprising: (i) a 33.3334 per cent. interest in the Upstream Segment; and (ii) its interests in the Midstream Segment.

Tullow Uganda's interests as described above are before any back-in by UNOC in the Upstream Segment. UNOC holds a back-in right of 15 per cent. in the production sharing agreements for Blocks 1, 1A, 2 and 3A. Following the exercise by UNOC of its back-in rights, the Interests will reduce to 28.3334 per cent. of the Upstream Segment. UNOC and Tanzania Petroleum Development Corporation are expected to participate for up to 15 and 5 per cent. respectively in the proposed EACOP System.

Tullow Uganda is currently the operator of Block 2. Total Uganda is currently the operator of Block 1 and Block 1A and CNOOC Uganda is operator of Block 3A.

Upstream Segment

The Upstream Segment includes nine production licences and two exploration licences in Uganda: (i) three production licences covering the former Block 1 area (covering the Ngiri, Jobi Rii and Gunya Fields), one exploration licence covering the Jobi East and Mpyo discoveries in the former Block 1 area which are subject to production licence applications submitted to the Government of Uganda, and one exploration licence covering the Lyec field in Block 1A which is also subject to a production licence application submitted to the Government of Uganda; (ii) five production licences in the former Block 2 area (covering the Mputa-Nzizi-Waraga, Kigogole-Ngara, Nsoga, Ngege and Kasamene-Wahrindi Fields); and (iii) one production licence covering the Kingfisher Discovery Area (which formed part of the former Block 3A). The licences are located along the Lake Albert Rift Basin in Uganda.

Midstream Segment

In February 2014, the Government of Uganda, the Company, Total Uganda and CNOOC Uganda signed a memorandum of understanding which allowed the upstream joint venture partners to develop an export pipeline via Kenya or Tanzania and provided for the sustainable development of the upstream fields and the development of a refinery.

In April 2016, the Government of Uganda confirmed its decision, after engagement with Kenyan and Tanzanian authorities, to route an oil export pipeline through Tanzania to the port of Tanga (the EACOP System). The Government of Uganda has established the Petroleum Authority of Uganda (the entity mandated to regulate the oil industry) and UNOC, which is the government representative in the Upstream Segment and Midstream Segment.

On 26 May 2017, the Governments of Uganda and Tanzania signed an inter-governmental agreement for the EACOP System. This has secured a harmonised framework for the EACOP System routing and allowed discussions to commence between the project sponsors and the Governments of Uganda and Tanzania on the host government agreements, the EACOP shareholders' agreement and other key commercial agreements. Financing for the Midstream Segment is also under discussion.

Past farm-down transactions

Through the acquisitions of Energy Africa and Hardman Resources in 2004 and 2006 respectively, the Company acquired a 50 per cent. interest in Blocks 1 and 3A and a 100 per cent. interest in Block 2. The

Company acquired the remaining 50 per cent. interest in Blocks 1 and 3A through the purchase of Heritage Oil's interests in July 2010.

In March 2011, the Company signed sale and purchase agreements to farm-down its interests in Blocks 1, 2 and 3A to CNOOC Uganda and Total Uganda for a consideration of US$2.9 billion, with each partner taking a one-third interest in each licence. In February 2012, the Company signed two production sharing agreements with the Government of Uganda (one for the Kanywataba prospect area (which formed part of the former Block 3A) which expired in August 2012 and one for Block 1A) which allowed the Company and its commercial partners to complete the farm-down. In February 2012, the Government of Uganda also granted the Company and its commercial partners a production licence in respect of the Kingfisher Discovery Area.

In June 2016, following submission of detailed field development plans, the Government of Uganda issued to the Company and its commercial partners, eight production licences: (i) three production licences covering the former Block 1 area (covering Ngiri, Jobi Rii and Gunya Fields); and (ii) five production licences in the former Block 2 area (covering Mputa-Nzizi-Waraga, Kigogole-Ngara, Nsoga, Ngege and Kasamene-Wahrindi Fields).

On 9 January 2017, the Company announced that it had agreed a further farm-down of its assets in Uganda to Total Uganda, as described in Section 8.2(b) of Part VI (*Additional Information*) of this document. CNOOC Uganda subsequently exercised its pre-emption rights in respect of the 2017 Uganda Sale Assets and entered into a sale and purchase agreement with Tullow Uganda in October 2017. In August 2019, the Company announced that the sale and purchase agreements with Total Uganda and CNOOC Uganda in relation to the 2017 Uganda Sale Assets had lapsed. This was a result of the parties being unable to agree all aspects of the tax treatment of the transaction with the Government of Uganda which was a condition precedent to completing the sale and purchase agreements.

The delay in completing the transfer of the 2017 Uganda Sale Assets and lapse of the related sale and purchase agreements stalled the development of the Upstream Segment and Total Uganda suspended work on the EACOP System. Discussions have been ongoing between the Government of Uganda, the Company and its commercial partners to agree the commercial and fiscal framework to enable the Upstream Segment and the Midstream Segment to move to a final investment decision.

Field technical background and development

In line with the production licence applications that were submitted, the Company and its commercial partners also presented a joint development proposal to the Government of Uganda that was based on two main oil and gas processing centres delivering a combined oil production rate of approximately 230,000 bopd at plateau from over 400 wells.

Since 2014, significant progress has been made with the Government of Uganda and the Company's commercial partners regarding the development options for the Lake Albert Development Project. The memorandum of understanding signed in February 2014 by the Company, its commercial partners and the Government of Uganda set out a basin-wide commercialisation plan. The memorandum of understanding envisaged an integrated development of upstream assets, an export pipeline and a refinery sized initially at 30,000 bopd with the potential to expand to 60,000 bopd to meet available market demand in East Africa. In August 2016, the Government of Uganda approved the application for eight production licences for certain of the fields covered by the former Block 1 and Block 2 areas.

During 2014, pre-project development work continued and included optimisation of well designs, the determination of the number of wells to be drilled and the design of the surface infrastructure. All exploration and appraisal drilling in the fields formerly within the Block 1 and Block 2 areas was also completed. CNOOC Uganda drilled a pre-development well in the Kingfisher Discovery Area in January 2015 and has carried out extensive pre-project development work, optimisation and, along with Total Uganda and the Company, has completed FEED for the Kingfisher Development. FEED for the Tilenga Development was completed in May 2018.

Recent developments and outlook

The planned development of Uganda's material oil resources remains at an advanced stage, with the Lake Albert Development Project's major technical aspects completed. There is no further exploration and appraisal activity planned on the existing production licences. The key Upstream Segment and Midstream Segment legal and commercial prerequisites for a final investment decision have been outlined to the Government of Uganda by Tullow Uganda and its commercial partners.

All major pre-development technical work for the Upstream Segment and the Midstream Segment has been completed including the FEED for the Midstream Segment (completed in December 2017) and the FEED for the Upstream Segment (completed in May 2018).

For the Upstream Segment, the ESIA certificate has been awarded for both the Tilenga Development and the Kingfisher Development. Progress has been made on securing land access for both upstream projects, and construction costs and schedules have been confirmed from the main EPC bid submissions for the Tilenga Development and Kingfisher Development. For the Midstream Segment, the ESIA certificate has been awarded in Tanzania, and the final ESIA report has been submitted to the Government of Uganda.

The gross commercial reserves and contingent resources associated with the Upstream Segment as described in the mineral expert's report prepared by TRACS and set out in Part VII (*Mineral Expert's Report*) of this document are shown in the following table.

	Uganda reserves & resources		
Gross Reserves and Resources	**Oil (mmbbl)**	**Gas (bcf)**	**Total (mmboe)**
Commercial Reserves (2P)	—	—	—
Contingent Resources (2C)	1,648.6	192.1	1,680.6
Total	**1,648.6**	**192.1**	**1,680.6**

The commercial reserves and contingent resources associated with the Upstream Segment and net to Tullow (following the exercise by UNOC of its back-in rights) as described in the mineral expert's report prepared by TRACS and set out in Part VII (*Mineral Expert's Report*) of this document are shown in the following table.

	Uganda reserves & resources		
Net Reserves and Resources	**Oil (mmbbl)**	**Gas (bcf)**	**Total (mmboe)**
Commercial Reserves (2P)	—	—	—
Contingent Resources (2C)	467.1	54.4	476.1
Total	**467.1**	**54.4**	**476.1**

A summary of the trading results for the Interests for the three years ended 31 December 2019 is set out in Part III (*Financial Information on the Interests*).

There was an operating loss of US$528.8 million associated with the Interests for the year ended 31 December 2019, comprising administrative expenses and exploration costs written off for such period that are not taken into account in the Group's gross profit. However, because there are no earnings attributable to the Interests, there would have been no impact on the Group's gross profit for the year ended 31 December 2019 had the Transaction completed on that date, with there being no gross profits attributable to the Interests for the year ended 31 December 2019. Had the Transaction completed on 31 December 2019, the Group's gross assets would have, before receipt of cash proceeds, reduced by US$992.2 million, being the gross asset amount of the Interests as at 31 December 2019, as set out in Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document.

11. Description of Total

Total is a major energy company that produces and markets fuels, natural gas and low-carbon electricity. It has been a producer of oil and gas for nearly a century with a presence in more than 130 countries on five continents. Total's activities include the exploration and production of oil and gas, refining, petrochemicals and the distribution of energy in various forms to the end customer.

In 2019, Total reported cash flow generated from operating activities of US$24.7 billion and adjusted net income of US$11.8 billion. The financial information set out in this paragraph has been extracted without material adjustment from Total's audited consolidated financial statements for the year ended 31 December 2019.

12. Interests and operatorship following the Transaction

Following Completion, the Retained Group will have interests in 62 licences in 12 countries and will be operator of: (i) two producing fields, the TEN and Jubilee fields in Ghana; (ii) four development blocks in Kenya; and (iii) 28 exploration licences spread across Africa and South America.

13. Working capital

Your attention is drawn to the working capital statement in Section 13 of Part VI (*Additional Information*) of this document. As set out in Section 13 of Part VI (*Additional Information*) of this document, Tullow is of the opinion that the Retained Group does not have sufficient working capital for its present requirements, which is for at least the next 12 months from the date of this document.

14. Risk factors

For a discussion of the risks and uncertainties which you should take into account when considering whether to vote in favour of the Resolution, please refer to Part II (*Risk Factors*) of this document.

15. General Meeting

A General Meeting is being convened at the offices of Tullow Oil plc, at 9 Chiswick Park, 566 Chiswick High Road, London W4 5XT at 12 noon (London time) on 15 July 2020 for the purpose of seeking Shareholder approval of the Resolution. A notice of the General Meeting is set out at the end of this document.

As described further in Section 16 below, the General Meeting will be a closed meeting. **Shareholders should not attempt to attend the General Meeting in person**. Any Shareholders who attempt to attend in person will be refused entry. **Shareholders should instead vote in advance by proxy**, as described in Section 16 below.

The Resolution will be proposed as an ordinary resolution requiring a majority of votes in favour. The Resolution proposes that: (i) the Transaction be approved; and (ii) the Directors be authorised to take all steps as may be necessary, expedient or desirable to implement the Transaction. The Transaction will not become effective unless the Resolution is passed.

16. Action to be taken

In light of the social distancing measures aimed at reducing the transmission of the COVID-19 virus in the United Kingdom, please note that attendance at the General Meeting in person is not possible and Shareholders should instead vote in advance by proxy by appointing the Chair of the General Meeting as their proxy in respect of all of their shares to vote on their behalf.

Continued Shareholder engagement remains very important to the Company and Shareholders will therefore be able to listen to a live audio-cast of the General Meeting and submit questions remotely throughout, as was possible for the Company's 2020 Annual General Meeting. Shareholders may also submit questions in advance via ir@tullowoil.com. Detailed instructions about voting by proxy and accessing the audio-cast are set out in Part IX (*Notice of General Meeting*) of this document.

Whether participating in the audio-cast or not, Shareholders are strongly encouraged to appoint the Chair of the General Meeting as their proxy, by completing and signing the enclosed Form of Proxy or by appointing a proxy via CREST or online.

You will find enclosed with this document a Form of Proxy for the General Meeting. You are asked to complete the Form of Proxy in accordance with the instructions printed on it and return it to Tullow's Registrars: (i) in the UK, Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol, BS99 6ZY, as soon as possible and, in any event, so as to be received by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting; or (ii) in Ghana, The Central Securities Depository (Ghana) Limited, 4th Floor, Cedi House, P.M.B CT 465 Cantonments, Accra, Ghana, as soon as possible and, in any event, so as to be received by no later than 11.00 a.m. (local time) on 10 July 2020, being 72 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting.

To ensure that all proxy votes can be counted and exercised at the General Meeting, Shareholders should ensure that they appoint the Chair of the Meeting as their proxy rather than any other individual(s). Due to the restrictions on physical attendance at the General Meeting, any other individual(s) will not be able to attend, speak or vote on members' behalf.

CREST members who wish to appoint a proxy through the CREST electronic proxy appointment service may do so by using the procedures described in the CREST Manual and by logging on to the following website: www.euroclear.com. CREST personal members or other CREST sponsored members, and those CREST members who have appointed (a) voting service provider(s), should refer to their CREST sponsor or voting service provider(s) who will be able to take the appropriate action on their behalf. You must appoint a proxy through CREST by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting. Further details are set out in the Notice of General Meeting set out in Part IX (*Notice of General Meeting*) of this document.

As an alternative to appointing a proxy using the Form of Proxy or CREST, you can appoint a proxy online at: www.investorcentre.co.uk/eproxy. In order to appoint a proxy using this website, you will need their Control Number, Shareholder Reference Number and PIN. This information is printed on the Form of Proxy. You must appoint a proxy using the website by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting.

In addition, members who are institutional investors may be able to appoint a proxy electronically via the Proxymity platform, a process which has been agreed by the Company and approved by Computershare Investor Services PLC. For further information regarding Proxymity, please visit www.proxymity.io. You must appoint a proxy via Proxymity by no later than 12 noon (London time) on 13 July 2020, being 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting. Before appointing a proxy via Proxymity, members will need to agree to Proxymity's associated terms and conditions. You should read such terms and conditions carefully as you will be bound by such terms and conditions, which will govern the electronic appointment of your proxy.

17. Further information

The expected timetable of principal events for the Transaction is set out on page 8 of this document.

Further information regarding the terms of the Transaction is set out in Part V (*Summary of the Principal Terms of the Transaction*) of this document.

Shareholders are advised to read the whole of this document and the accompanying Form of Proxy and not rely solely on the summarised information set out in this letter.

18. Financial advice

The Board has received financial advice from each of Barclays, J.P. Morgan Cazenove and Robey Warshaw in relation to the Transaction. In providing its financial advice to the Board, each of Barclays, J.P. Morgan Cazenove and Robey Warshaw has relied upon the Board's commercial assessments of the Transaction.

19. Recommendation to Shareholders

Importance of vote

Your attention is drawn to the fact that the Transaction is conditional and dependent upon, amongst other things, the Resolution being passed at the General Meeting.

Shareholders are asked to vote in favour of the Resolution in order for the Transaction to proceed. If the Resolution is not passed by Shareholders, the Transaction cannot complete and the Company will not receive the proceeds of the Transaction. The Board would emphasise that if the Transaction does not proceed, the Group may lose this opportunity to realise proceeds for the Interests at an attractive valuation and to reduce its Net Debt and may suffer further adverse effects as described below.

The Group's RBL Facility contains both a periodic test of forecast liquidity (the Liquidity Forecast Test) and a covenant in respect of the Group's level of gearing (the RBL Gearing Covenant), each described in more detail below. A failure to satisfy either may lead to an event of default under the RBL Facility. Completion of the Transaction is not forecast to: (i) be sufficient for the Group to meet the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020; or (ii) mitigate fully the potential liquidity shortfall in respect of the Liquidity Forecast Test at the March 2021 RBL Facility redetermination, as set out in Section 13 of Part VI (*Additional Information*) of this document. However, the Group is committed to reducing its overall level of Net Debt and the Transaction is an important step towards achieving this.

Consequences of the Transaction failing to complete

It is not possible for the Board, particularly in light of current trading conditions and, especially, the COVID-19 pandemic and the high levels of market volatility and uncertainty arising therefrom, to determine with absolute certainty the quantum of any forecasted liquidity shortfall which could result in a failure to pass the Liquidity Forecast Test or any forecasted non-compliance with the RBL Gearing Covenant.

However, based on (i) current trading expectations and the average realisable oil price the Directors believe to be applicable for the assessment of the reasonable worst case scenario (as described below) and (ii) all of the Group's debt obligations being repaid in full on the contractual maturity dates (rather than refinanced in accordance with past practice), the Group's working capital projections forecast a potential liquidity shortfall during the 18-month period relevant to the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination should Completion (i) not occur or (ii) be delayed such that the lenders under the RBL Facility are unwilling to take into account in the Liquidity Forecast Test projections the proceeds to be received by the Group in respect of the Transaction. This could result in an event of default under the RBL Facility allowing the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights, which could in turn trigger cross-defaults under the other financing arrangements of the Retained Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes) by the end of December 2020. The amount repayable should the lenders under the RBL Facility decide to exercise their right to demand that all outstanding borrowings under the RBL Facility be repaid and the Group's creditors exercise their right to trigger a cross-default under the Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Group's borrowings is immediately repayable, was US$3.255 billion as at 31 May 2020. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

(a) Relevant provisions of the RBL Facility

Liquidity Forecast Test

As part of the bi-annual RBL Facility redetermination process in March and September each year, the Group is required to demonstrate to the reasonable satisfaction of the relevant majority of its lenders under the RBL Facility that it has, or will have, sufficient funds available to meet the Group's financial commitments for a period of 18 months from 1 April or 1 October following the relevant RBL Facility redetermination (the "Liquidity Forecast Test").

RBL Gearing Covenant test

The RBL Facility contains a covenant, which is tested for each 12-month period ending on 30 June and 31 December each year, which requires that net debt of the Group (as calculated in accordance with the RBL Facility Agreement and referred to in this document as the "Covenanted Net Debt") must be lower than 3.5 times consolidated EBITDA (as calculated in accordance with the RBL Facility Agreement and referred to in this document as the "Consolidated EBITDA") for each relevant 12-month period (except for the 12-month period ending 30 June 2020, when Covenanted Net Debt must be lower than 4.5 times Consolidated EBITDA) (the "RBL Gearing Covenant"). The concepts of Covenanted Net Debt and Consolidated EBITDA should be distinguished from the concepts of Net Debt and Adjusted EBITDAX as set out in the Group's latest annual accounts (being those for the year ended 31 December 2019) and used elsewhere in this document.

(b) September 2020 Liquidity Forecast Test, timing and action plan

In the event that Completion (i) does not occur or (ii) is delayed such that the lenders under the RBL Facility are unwilling to take into account in the Liquidity Forecast Test projections the proceeds to be received by the Group in respect of the Transaction, in the reasonable worst case scenario a potential liquidity shortfall in relation to the Group's financial commitments of approximately US$40 million is first forecasted to arise in May 2021 (which is within the 18-month testing period from October 2020 to March 2022 inclusive that is relevant to determining whether the Company will pass the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination). This has been modelled on what the Directors believe to be the reasonable worst case scenario based on the average realisable oil price being US$25/bbl for the 2020 financial year, US$35/bbl for the 2021 financial year and US$45/bbl for the 2022 financial year. If the Company is unable to demonstrate to the reasonable satisfaction of the relevant majority of its lenders under the RBL Facility that it has, or will have, sufficient funds available to meet the Group's financial commitments for the 18-month testing period from October 2020 to March 2022 inclusive (for example, because the lenders under the RBL Facility do not take into account the potential positive impact of the mitigating actions described below), and the Company is unable to cure the forecast liquidity shortfall within 90 days following the date on which it becomes aware that it has not passed the Liquidity Forecast Test, there would be an event of default under the RBL Facility by the end of December 2020.

Such event of default would allow the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights. This would in turn trigger creditors' rights to call cross-defaults under the other financing arrangements of the Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes). Enforcement action taken by the relevant trustees on instruction of the bondholders could result in the entirety of the Group's borrowings potentially becoming immediately repayable by the end of December 2020.

The Directors note that passing the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination would require satisfying the relevant majority of lenders in relation to the Group's liquidity. This is therefore outside the control of the Group. As at the date of this document, the Group has not approached the relevant lenders in respect of the September 2020 RBL Facility redetermination.

In the event that Completion does not appear likely to occur by the end of September 2020, or at all, the Group may consider taking one or more of the following actions which the Group's management believes could be progressed sufficiently by the end of September 2020 such that the Group would be able to pass the Liquidity Forecast Test at the September 2020 RBL Facility redetermination:

(i) securing a new liquidity facility from banks or capital markets investors. While the Directors believe that the Group has strong relationships with its lending banks and a track record of accessing capital markets, there can be no assurance that the Group's lending banks or any other investor would agree to provide such a facility. In addition, the Directors note that, in light of the increased regulatory oversight and requirements under which banks and investors operate and the volatility of oil prices, there has been a reduction in certain banks' and investors' willingness and ability to lend to or invest in entities in the oil and gas industry. Accordingly, the Directors cannot be confident that the Retained Group will be able to secure or obtain additional financing on commercially acceptable terms, or at all;

(ii) seeking to agree more beneficial technical and/or economic assumptions with its lenders or seeking to amend the commercial terms of the RBL Facility in order to increase debt capacity. The Directors note that these actions would require the approval of the relevant majority of lenders under the RBL Facility and are therefore outside of the control of the Group Accordingly, the Directors cannot be confident that this could be achieved;

(iii) initiating a further rationalisation of its cost base (in addition to measures already implemented since December 2019) through a further reduction of general and administrative costs. The Directors are reasonably confident that a further reduction of approximately US$25 million per annum can be achieved from 2021 onwards; and

(iv) initiating cuts to discretionary capital investment (in addition to measures already implemented since December 2019 and, for example, by focussing on maintenance of producing fields only and substantially reducing investment in development, exploration and appraisal activities) and deferring decommissioning expenditure. The Directors note that initiating cuts to discretionary capital investment and deferring decommissioning expenditure: (a) may require approval from third parties including its commercial partners and there can be no assurances that these approvals will be obtained; and (b) are dependent to an extent upon the Group's ability to execute strategic opportunities in relation to asset disposals and there can be no assurance that it will be possible to make any such disposals. Accordingly, the Directors cannot quantify any savings that may arise out of such measures or be confident that any such measures will be successful.

While the Directors would consider the above actions in parallel, the Directors cannot be certain that these mitigating actions will be capable of addressing the forecasted liquidity shortfall in the time available, or at all.

If it appeared likely that the Group's management would be unable to progress sufficiently the actions described above by the end of September 2020 in order for the Group to be able to pass the Liquidity Forecast Test at the September 2020 RBL Facility redetermination, the Group may consider initiating the negotiation of a refinancing proposal with its creditors to achieve certain amendments to the terms of the RBL Facility, the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes that would reduce the liquidity impact of servicing such borrowings and/or extend the maturity of such borrowings with, if necessary, that proposal being approved by Shareholders. Whilst a refinancing proposal initiated by the Group may result in more favourable terms than a refinancing proposal initiated following an event of default as described below, there is no certainty that the creditors would engage with the Group in such circumstances and such a proposal would therefore be outside of the control of the Group. Accordingly, the Directors cannot be confident that this could be achieved.

Event of default

The amount outstanding under the Group's RBL Facility which could be required to be repaid should the lenders under the RBL Facility exercise their right to accelerate repayment of amounts owing under the RBL Facility following an event of default under the RBL Facility as described above was US$1.505 billion as at 31 May 2020. The amount repayable should the Group's creditors then exercise their right to trigger a cross-default under the Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Group's borrowings, including the amount outstanding under the Group's RBL Facility, is immediately repayable, was US$3.255 billion as at 31 May 2020. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

In the circumstances described above and where the Board is unable to obtain such additional sources of liquidity, the Group might have to enter into insolvency proceedings and counterparties to material contracts might seek to exercise termination rights under those contracts. The ability of the Group to continue trading would depend upon the Group being able to negotiate a refinancing proposal with its creditors as described above and, if necessary, that proposal being approved by Shareholders. Whilst the Board would seek to negotiate such a refinancing proposal with its creditors, there is no certainty that the creditors would engage with the Board in those circumstances. There would therefore be a significant risk of the Group entering into insolvency proceedings, which the Directors consider would likely result in limited or no value being returned to Shareholders.

In the context of the current prospects of the Group, it is important that all Shareholders vote in favour of the Resolution so that the Transaction may proceed.

Recommendation

The Board considers that the Transaction is in the best interests of Tullow and its Shareholders taken as a whole. Accordingly, the Board unanimously recommends that Shareholders vote or procure votes in favour of the Resolution to be proposed at the General Meeting.

The Directors each intend to vote in favour of the Resolution at the General Meeting in respect of their own Tullow Shares to which they are beneficially entitled.

Yours faithfully
for and on behalf of Tullow

Dorothy Thompson CBE
Executive Chair

PART II—RISK FACTORS

This Part II (*Risk Factors*) addresses the risks known to Tullow and the Directors as at the date of this document which are material risk factors to the proposed Transaction, will be material risk factors to the Group or, following Completion, the Retained Group as a result of the proposed Transaction, or are existing material risk factors to the Tullow Group which will be impacted by the proposed Transaction. The risk factors included are risks which could materially and adversely affect the business, financial condition, results of operations and/or prospects of the Group or, following Completion, the Retained Group, as appropriate. In such cases, the market price of the Tullow Shares could decline and investors may lose all or part of their investment.

Prior to making any decision to vote in favour of the Resolution, Shareholders should carefully consider, together with all other information contained in this document, the specific risks and uncertainties described below.

A number of factors affect the business, financial condition, results of operations and/or prospects of the Group or, following Completion, the Retained Group. The following is not an exhaustive list or an explanation of all risks that investors may face as holders of Tullow Shares and should be used as guidance only. Additional risks and uncertainties that are not presently known to the Group or, following Completion, the Retained Group, or that are currently deemed immaterial, may individually or cumulatively also have a material adverse effect on the Group's or, following Completion, the Retained Group's business, financial condition, results of operations and/or prospects. If any risk of which Tullow or the Directors are unaware, or that is currently deemed immaterial, should occur, the market price of the Tullow Shares could decline and investors may lose all or part of their investment.

The information given is as at the date of this document and, except as required by the FCA, the London Stock Exchange, Euronext Dublin, the Ghana Stock Exchange, the Listing Rules, the Irish Listing Rules or any other applicable law, will not be updated. Any forward-looking statements are made subject to the reservations specified under "Forward-looking statements" on page 2 of this document.

1. Risks related to the Transaction

The following risks and uncertainties relate to the Transaction:

Conditions and termination rights in the Sale and Purchase Agreement

Completion of the Sale and Purchase Agreement is conditional upon the fulfilment or waiver of various conditions, including:

(a) the URA and Government of Uganda entering into the Tax Agreement reflecting the agreed principles of the tax treatment of the Transaction;

(b) the Company having obtained the approval of its Shareholders as required under the Listing Rules; and

(c) the Minister Consents.

Prior to the Transaction Announcement, Tullow and Total had supportive discussions with the Government of Uganda and the URA, including to agree the principles of the tax treatment of the Transaction (including the position on Ugandan tax on capital gains, which is to be remitted by Total Uganda on behalf of Tullow Uganda, and which is expected to be US$14.6 million in respect of the US$575 million of cash consideration), and Tullow consulted with Shareholders holding approximately 27.5 per cent. in aggregate of Tullow's issued share capital at that time and reported in the Transaction Announcement that such Shareholders indicated their support for the Transaction. Tullow applied on 4 June 2020 for the Minister Consents.

However, there can be no assurance that any of the conditions to Completion (which depend upon third parties and may also be subject to other third party interference) will be satisfied (or waived) on a timely basis or at all, in which case the Transaction may be delayed or may fail to complete. The conditions to completion were not satisfied or waived in relation to the 2017 Uganda Assets Farm-down, as a result of the parties being unable to agree all aspects of the tax treatment of that transaction with the Government of Uganda (which was a condition precedent to completing the sale and purchase agreements for the 2017 Uganda Assets Farm-down).

Total Uganda has the right to terminate the Sale and Purchase Agreement between signing and Completion in certain circumstances if there is a material adverse event, which includes: (i) a breach of fundamental warranty by Tullow Uganda; (ii) any action or claim by a third party seeking to restrain or materially alter the transactions contemplated by the Sale and Purchase Agreement ; or (iii) an event or series of related events occurring in Uganda, where each of (i), (ii) or (iii) results in a reduction in the value of the Interests in excess of US$86.25 million (and in each case certain macro-events such as changes in hydrocarbon prices, market conditions and COVID-19 are excluded); or (iv) an insolvency event in respect of the Company, Tullow Uganda or any holding company of Tullow Uganda.

Tullow Uganda and Total Uganda each has the right to terminate the Sale and Purchase Agreement between signing and Completion if: (i) the URA or any other Ugandan Government Authority challenges or revokes or purports to revoke or threatens to revoke the Tax Agreement once entered into; (ii) there is a breach of specific warranties and undertakings given in respect of anti-bribery and corruption; or (iii) if any of the conditions precedent to Completion are not satisfied or waived by 23 October 2020 (unless the parties mutually agree to extend such date).

There can be no assurance that these termination rights will not be exercised if applicable (for example, if a third party were able to obtain a freezing order in respect of the Transaction). If they are so exercised, the Transaction will fail to complete.

If the Transaction does not complete on a timely basis, any of the risks and uncertainties set out in Section 2 of this Part II (*Risk Factors*) may adversely affect the Group's business, financial condition, results of operations and/or prospects.

Third party interference arising out of alternative transactions which may compete with the Transaction

The Company could receive approaches from third parties seeking to instigate a public takeover of the Company or an alternative transaction involving the Interests. Although the Sale and Purchase Agreement is binding on Tullow and Tullow Uganda (such that they would be obliged to proceed to Completion in the event that all conditions (including the obtaining of Shareholder approval) had been satisfied), the Directors would be obliged to consider any attractive alternative offer in accordance with their fiduciary duties and may as a result of any such offer withdraw their recommendation of the Resolution and the Transaction. Any such withdrawal of the Board's recommendation of the Resolution might delay or prevent Completion of the Transaction without necessarily resulting in completion of a more favourable transaction, which may adversely affect the Group's business, financial condition, results of operations and/or prospects.

Deferred and contingent consideration

The consideration pursuant to the Transaction contains the following elements of deferred and contingent consideration:

(a) deferred consideration of US$75 million following the final investment decision for the Upstream Segment and the Midstream Segment; and

(b) annual contingent consideration payable by Total on upstream revenues from the Interests (reducing to 28.3334 per cent. following the exercise by UNOC of its back-in rights) once production commences, at an amount equal to 1.25 per cent. (net of tax) if the average annual Brent price is greater than US$62/bbl or 2.5 per cent. (net of tax) if the average annual Brent price is greater than US$70/bbl. No payment will be due in respect of the contingent consideration if the average annual Brent price in respect of the relevant year is less than or equal to US$62/bbl.

As the deferred consideration is linked to a final investment decision in respect of the Upstream Segment and Midstream Segment and the contingent consideration is linked to future oil prices, there is a risk that the Retained Group will not receive some or all of such deferred and/or contingent consideration if there is no final investment decision and/or oil prices remain at or below the thresholds for contingent consideration to be paid (US$62/bbl and US$70/bbl).

The key legal and commercial prerequisites to a final investment decision for the Upstream Segment and Midstream Segment have been outlined to the Government of Uganda by Tullow Uganda and its commercial partners. Such prerequisites include execution of the commercial agreements underlying the Upstream Segment and Midstream Segment including host government agreements, the shareholders' agreement and transportation agreement related to the EACOP System, the Government of Uganda passing the relevant enabling legislation to support the Upstream Segment and Midstream Segment, finalising the funding arrangements for the Upstream Segment and Midstream Segment, executing all construction contracts and obtaining all required permits including land access. As such, there is significant uncertainty surrounding the timing and likelihood of the final investment decision for the Upstream Segment and the Midstream Segment.

There can be no assurance that any element of deferred and/or contingent consideration will become payable.

Warranties and indemnities in the Sale and Purchase Agreement

The Sale and Purchase Agreement contains customary warranties and indemnities given by the Company in favour of Total Uganda. The Company has undertaken due diligence to minimise the risk of liability under these provisions. However, any liability to make a payment arising from a successful claim by Total Uganda under the warranties or indemnities may adversely affect the Retained Group's business, financial condition, results of operations and/or prospects. Further, a claim in respect of a breach of a fundamental warranty or pursuant to an indemnity under the Sale and Purchase Agreement that led to a court judgment or arbitral award against the Group of greater than or equal to US$300 million would constitute an event of default under the Group's RBL Facility which could lead to cross-default under the Group's other financing agreements and enforcement of security against the Group.

2. Risks related to the Transaction not proceeding

If the Transaction does not proceed, the following risks and uncertainties may affect the Group's business, financial condition, results of operations and/or prospects:

The Company may face risks associated with its funding position if Completion is delayed or the Transaction does not complete

If Completion is delayed or the Transaction does not complete, the Group will not receive the proceeds from the Transaction on a timely basis or at all and consequently may not be able to reduce its Net Debt in the near future. Ongoing financing costs may exceed the free cash flow generated by the Group from its operations, resulting in the need to draw more debt under the RBL Facility.

Based on (i) current trading expectations and the average realisable oil price the Directors believe to be applicable for the assessment of the reasonable worst case scenario (as described below) and (ii) all of the Group's debt obligations being repaid in full on the contractual maturity dates (rather than refinanced in accordance with past practice), the Group's working capital projections forecast a potential liquidity shortfall during the 18-month period relevant to the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination should Completion (i) not occur or (ii) be delayed such that the lenders under the RBL Facility are unwilling to take into account in the Liquidity Forecast Test projections the proceeds to be received by the Group in respect of the Transaction. This could result in an event of default under the RBL Facility allowing the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights, which could in turn trigger cross-defaults under the other financing arrangements of the Retained Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes) by the end of December 2020. The amount repayable should the lenders under the RBL Facility decide to exercise their right to demand that all outstanding borrowings under the RBL Facility be repaid and the Group's creditors exercise their right to trigger a cross-default under the Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Group's borrowings is immediately repayable, was US$3.255 billion as at 31 May 2020. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

In the event that Completion (i) does not occur or (ii) is delayed such that the lenders under the RBL Facility are unwilling to take into account in the Liquidity Forecast Test projections the proceeds to be received by the Group in respect of the Transaction, in the reasonable worst case scenario a potential liquidity shortfall in relation to the Group's financial commitments of approximately US$40 million is first forecasted to arise in May 2021 (which is within the 18-month testing period from October 2020 to March 2022 inclusive that is relevant to determining whether the Company will pass the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination). This has been modelled on what the Directors believe to be the reasonable worst case scenario based on the average realisable oil price being US$25/bbl for the 2020 financial year, US$35/bbl for the 2021 financial year and US$45/bbl for the 2022 financial year. If the Company is unable to demonstrate to the reasonable satisfaction of the relevant majority of its lenders under the RBL Facility that it has, or will have, sufficient funds available to meet the Group's financial commitments for the 18-month testing period from October 2020 to March 2022 inclusive (for example, because the lenders under the RBL Facility do not take into account the potential positive impact of the mitigating actions described below), and the Company is unable to cure the forecast liquidity shortfall within 90 days following the date on which it becomes aware that it has not passed the Liquidity Forecast Test, there would be an event of default under the RBL Facility by the end of December 2020.

Such event of default would allow the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights. This would in turn trigger creditors' rights to call cross-defaults under the other financing arrangements of the Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes). Enforcement action taken by the relevant trustees on instruction of the bondholders could result in the entirety of the Group's borrowings potentially becoming immediately repayable by the end of December 2020.

The Directors note that passing the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination would require satisfying the relevant majority of lenders in relation to the Group's liquidity. This is therefore outside the control of the Group. As at the date of this document, the Group has not approached the relevant lenders in respect of the September 2020 RBL Facility redetermination.

In the event that Completion does not appear likely to occur by the end of September 2020, or at all, the Group may consider taking one or more of the following actions which the Group's management believes could be progressed sufficiently by the end of September 2020 such that the Group would be able to pass the Liquidity Forecast Test at the September 2020 RBL Facility redetermination:

(i) securing a new liquidity facility from banks or capital markets investors. While the Directors believe that the Group has strong relationships with its lending banks and a track record of accessing capital markets, there can be no assurance that the Group's lending banks or any other investor would agree to provide such a facility. In addition, the Directors note that, in light of the increased regulatory oversight and requirements under which banks and investors operate and the volatility of oil prices, there has been a reduction in certain banks' and investors' willingness and ability to lend to or invest in entities in the oil and gas industry. Accordingly, the Directors cannot be confident that the Retained Group will be able to secure or obtain additional financing on commercially acceptable terms, or at all;

(ii) seeking to agree more beneficial technical and/or economic assumptions with its lenders or seeking to amend the commercial terms of the RBL Facility in order to increase debt capacity. The Directors note that these actions would require the approval of the relevant majority of lenders under the RBL Facility and are therefore outside of the control of the Group. Accordingly, the Directors cannot be confident that this could be achieved;

(iii) initiating a further rationalisation of its cost base (in addition to measures already implemented since December 2019) through a further reduction of general and administrative costs. The Directors are reasonably confident that a further reduction of approximately US$25 million per annum can be achieved from 2021 onwards; and

(iv) initiating cuts to discretionary capital investment (in addition to measures already implemented since December 2019 and, for example, by focussing on maintenance of producing fields only and substantially reducing investment in development, exploration and appraisal activities) and deferring decommissioning expenditure. The Directors note that initiating cuts to discretionary capital investment and deferring decommissioning expenditure: (a) may require approval from third parties including its commercial partners and there can be no assurances that these approvals will be obtained; and (b) are dependent to an extent upon the Group's ability to execute strategic opportunities in relation to asset disposals and there can be no assurance that it will be possible to make any such disposals. Accordingly, the Directors cannot quantify any savings that may arise out of such measures or be confident that any such measures will be successful.

While the Directors would consider the above actions in parallel, the Directors cannot be certain that these mitigating actions will be capable of addressing the forecasted liquidity shortfall in the time available, or at all.

If it appeared likely that the Group's management would be unable to progress sufficiently the actions described above by the end of September 2020 in order for the Group to be able to pass the Liquidity Forecast Test at the September 2020 RBL Facility redetermination, the Group may consider initiating the negotiation of a refinancing proposal with its creditors to achieve certain amendments to the terms of the RBL Facility, the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes that would reduce the liquidity impact of servicing such borrowings and/or extend the maturity of such borrowings with, if necessary, that proposal being approved by Shareholders. Whilst a refinancing proposal initiated by the Group may result in more favourable terms than a refinancing proposal initiated following an event of default as described below, there is no certainty that the creditors would engage with the Group in such circumstances and such a proposal would therefore be outside of the control of the Group. Accordingly, the Directors cannot be confident that this could be achieved.

Event of default

The amount outstanding under the Group's RBL Facility which could be required to be repaid should the lenders under the RBL Facility exercise their right to accelerate repayment of amounts owing under the RBL Facility following an event of default under the RBL Facility as described above was US$1.505 billion as at 31 May 2020. The amount repayable should the Group's creditors then exercise their right to trigger a cross-default under the Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Group's borrowings, including the amount outstanding under the Group's RBL Facility, is immediately repayable, was US$3.255 billion as at 31 May 2020. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

In the circumstances described above and where the Board is unable to obtain such additional sources of liquidity, the Group might have to enter into insolvency proceedings and counterparties to material contracts might seek to exercise termination rights under those contracts. The ability of the Group to continue trading would depend upon the Group being able to negotiate a refinancing proposal with its creditors as described above and, if necessary, that proposal being approved by Shareholders. Whilst the Board would seek to negotiate such a refinancing proposal with its creditors, there is no certainty that the creditors would engage with the Board in those circumstances. There would therefore be a significant risk of the Group entering into insolvency proceedings, which the Directors consider would likely result in limited or no value being returned to Shareholders.

In addition, if Completion is delayed or the Transaction does not complete (and subject to the Group being able to avoid insolvency proceedings as set out above), the Group would be required to meet its funding requirements in relation to the Interests (including, potentially, the Midstream Segment) when it would not otherwise have expected to have to do so had Completion occurred. This would reduce the Group's ongoing free cash flow. If Tullow was subsequently unable to meet its funding requirements under the Joint Operating Agreements, this would mean Tullow Uganda would be in breach of its obligations, which may result in: (i) the operator applying Tullow Uganda's share of the proceeds from the sale of any oil produced to the amounts in default; and (ii) the other contracting parties requiring Tullow Uganda's withdrawal from the Joint Operating Agreements and the related production sharing agreements, with its participation transferred to the remaining parties under these agreements.

In addition, in such circumstances, the Board may decide (in order to reallocate free cash flow in the near term) to reduce or delay some of the Group's current capital expenditure plans, which may adversely impact the Group's future production and the Group's reserves, as well as the Group's future prospects with respect to its development projects in East Africa and elsewhere and its new ventures activities.

Loss of shareholder value

The Board believes that the Transaction is in the best interests of Shareholders and that the Transaction provides the best opportunity to realise an attractive and certain value for the Interests. If the Transaction does not complete, the value realised by the Group for the Interests may be lower than can be realised by way of the Transaction. If the Transaction does not complete and the Group retains the Interests (because the Group is unable or decides not to pursue another transaction in relation to the Interests) (and subject to the Group being able to avoid insolvency proceedings as set out above), the Group may not be able to realise any value from the Interests if it does not support the final investment decision on the Lake Albert Development Project for any reason, including if supporting the final investment decision on the Lake Albert Development Project is not in the strategic interests of the Group or insufficient funding is available to meet the Group's share of development costs associated with the Interests. For further information on risks specific to the Group's funding position, please see the risk factor entitled "*The Company may face risks associated with its funding position if Completion is delayed or the Transaction does not complete*" in this Section 2 of Part II (*Risk Factors*) of this document.

No assurance of future sale

If the Transaction does not complete, there is no assurance that the Group would be able to dispose of the Interests at a later date, in favourable or equivalent market circumstances, or to dispose of the Interests at all. If the Group is unable to identify another suitable purchaser for the Interests, this could lead to a loss of confidence amongst relevant stakeholders and a reduced value of the Interests.

In addition, even if the Group were able to identify another suitable purchaser for the Interests: (i) the Minister Consents would need to be obtained; and (ii) the pre-emption rights of the Group's commercial partners, Total

Uganda and CNOOC Uganda, would need to be addressed. There is no assurance that such approvals, consents or agreements would be forthcoming under any such alternative transaction.

There may be an adverse impact on the Group's reputation and business relationships if the Transaction does not complete

If the Transaction does not complete, there may be an adverse impact on the reputation of the Group due to amplified media and market scrutiny arising in connection with a failed Transaction. In particular, failure to complete the Transaction may result in a loss of trust from Shareholders, debt holders and other stakeholders in the ability of the Board and the Company's management to deliver its publicly stated strategy of raising in excess of US$1 billion of proceeds from portfolio management. Any such reputational risk could adversely affect the Group's business, financial condition, results of operations and/or prospects. This scrutiny would be heightened in light of the Company's previously unsuccessful attempt to sell a stake in the Interests pursuant to the 2017 Uganda Assets Farm-down.

In addition, failure to complete the Transaction may have an adverse impact on the Company's relationships with its stakeholders in the Interests because its attractiveness as a counterparty may be reduced. This may negatively impact the Group's ability to monetise the Interests in the future as well as the Group's dealings with the same commercial partners and stakeholders.

Potentially disruptive effect

If the Transaction does not complete, the Group's management and employees dedicated to the Interests may be affected, some of whom may choose to leave. This may have a negative effect on the performance of the Interests under the Group's ownership and operatorship. To maintain shareholder value, the management of the Interests and of the Group may be required to allocate additional time and cost to the ongoing supervision and development of the Interests, which could in turn adversely impact the Group's ability to manage its other assets and the overall Group cost base and adversely affect the Group's business, financial condition, results of operations and/or prospects.

The Group will continue to operate and hold the Interests with commercial partners which may increase the risk of disputes, delays, additional costs or the suspension and termination of the licences or the agreements which govern its assets

If the Transaction does not complete, the Group will remain operator of Block 2. As the operator of Block 2, the Group is dependent on its commercial partners, Total Uganda and CNOOC Uganda, complying with their obligations under the production sharing agreement for Block 2, the relevant production licences and the Joint Operating Agreement relating to Block 2. Failure by the Group (acting with its commercial partners) to comply with the relevant obligations may lead to fines, penalties, restrictions and withdrawal of licences or termination of the agreements under which it operates.

Typically, as operator the Group is able to direct or control certain of the activities or operations relating to a particular asset. There is a risk that a commercial partner with licence interests in an asset may elect not to participate in certain activities which the Group believes are required. In addition, in certain cases the consent of a commercial partner is required to undertake a particular course of action. Where consent is not forthcoming or a commercial partner refuses to follow the Group's proposed course of action, it may not be possible for such activities to be undertaken by the Group alone or in conjunction with other commercial partners at the desired time or at all or otherwise, to the extent permitted, such activities may then need to be undertaken with the Group bearing a greater proportion of the risks and costs involved in the project.

In addition, the Group may suffer unexpected costs or losses if a commercial partner does not meet obligations under agreements governing the relationship. For example, a commercial partner may default on its obligations to fund capital or other funding obligations in relation to such assets. In such circumstances, the Group may be required under the terms of the relevant operating agreement to contribute all or part of any such funding shortfall, regardless of the percentage interests that it agreed with such commercial partner under such arrangements. Typically, the defaulting commercial partner will be required to cure its default in a period of time set out under the relevant agreement. Where the defaulting party refuses, or is unable, to cure its default, the Group and the other commercial partners may acquire the defaulting partner's interest in the licence. As a result, and despite the original intentions of the Group, its exposure to a particular licence may increase such that the Group bears a greater proportion of the risks and costs involved which may have a material adverse effect on the Group's business, financial condition, results of operations and/or prospects.

In addition, the Group may also be subject to claims by its commercial partners regarding potential non-compliance with its obligations. It is also possible that the interests of the Group, on the one hand, and those of its commercial partners, on the other will not always be aligned and could result in possible project delays, disagreements or additional costs to the Group.

3. Risks related to the Group and, following Completion of the transaction, the Retained Group

The Retained Group does not have sufficient working capital for its present requirements

The scenarios referred to in this risk factor have been prepared on the basis of (i) what the Directors believe to be the reasonable worst case scenario based on the average realisable oil price being US$25/bbl for the 2020 financial year, US$35/bbl for the 2021 financial year and US$45/bbl for the 2022 financial year; (ii) what the Directors believe to be the base case scenario based on the average realisable oil price being US$35/bbl for the 2020 financial year, US$45/bbl for the 2021 financial year and US$55/bbl for the 2022 financial year; and (iii) the Convertible Bonds due in July 2021 and the 2022 Senior Notes due in April 2022 being repaid in full on the contractual maturity dates (rather than refinanced in accordance with past practice).

Even if Completion occurs, in both the reasonable worst case scenario and the base case scenario, the Retained Group may fail to pass the Liquidity Forecast Test and/or breach the RBL Gearing Covenant during the Working Capital Period. This could result in an event of default under the RBL Facility allowing the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights, which could in turn trigger cross-defaults under the other financing arrangements of the Retained Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes) by mid to end of June 2021. The amount repayable should the lenders under the RBL Facility decide to exercise their right to accelerate the RBL Facility and the Retained Group's creditors exercise their right to trigger a cross-default under the Retained Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Retained Group's borrowings is immediately repayable, was US$3.255 billion as at 31 May 2020. But for such circumstances, the Retained Group would expect to have sufficient working capital for its requirements during the Working Capital Period. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

It is not possible for the Board, particularly in light of current trading conditions and, especially, the COVID-19 pandemic and the high levels of market volatility and uncertainty arising therefrom, to determine with absolute certainty any forecasted non-compliance with the RBL Gearing Covenant or the quantum of any forecasted liquidity shortfall which could result in a failure to pass the Liquidity Forecast Test. However, based on current trading expectations, the Retained Group's working capital projections in respect of a potential breach of the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020 and a potential failure to pass the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination are set out below, each in the reasonable worst case scenario and the base case scenario and assuming that Completion occurs.

31 December 2020 RBL Gearing Covenant test, timing and action plan

In the reasonable worst case scenario, the Retained Group forecasts a Covenanted Net Debt to Consolidated EBITDA ratio of 5.0 times in respect of the financial covenant 12-month testing period ending 31 December 2020 (such that the Retained Group would exceed the permitted RBL Gearing Covenant test ratio by 1.5 times as a result of a forecasted Consolidated EBITDA shortfall of approximately US$280 million). Further, in the base case scenario, the Retained Group forecasts a Covenanted Net Debt to Consolidated EBITDA ratio of 3.9 times in respect of the financial covenant 12-month testing period ending 31 December 2020 (such that the Retained Group would exceed the permitted RBL Gearing Covenant test ratio by 0.4 times as a result of a forecasted Consolidated EBITDA shortfall of approximately US$100 million).

An event of default under the RBL Facility as a result of this breach of the RBL Gearing Covenant will arise when:

(a) Tullow delivers to the relevant lenders a notification of non-compliance with the RBL Gearing Covenant, which is required to be delivered as soon as Tullow's audited financial statements for the year ended 31 December 2020 are available but no later than 30 April 2021; and

(b) a subsequent 75-day period expires without the Company having resolved the non-compliance, either by: (i) seeking agreement with its lenders to waive the non-compliance or (ii) procuring a cash subscription for Tullow Shares and/or receipt of an injection of cash by way of certain subordinated debt such that the relevant ratio is satisfied by reducing Covenanted Net Debt accordingly. The Company would be prohibited from drawing any further available amounts under the RBL Facility during this period.

In this scenario and unless the Retained Group is able to agree an amendment or waiver with the relevant lenders, there will be an event of default under the RBL Facility by mid-June 2021.

The Group continues to closely monitor cash flow forecasts and to explore actions to improve its forecast financial position and maintain compliance with its external debt facilities, including securing amendments to or waivers of covenants if necessary.

In order to address the potential breach of the RBL Gearing Covenant for the 12-month testing period ending 31 December 2020, the Group's management expects that it will seek an amendment of the covenant in advance of the relevant assessment, or a waiver, such that the RBL Gearing Covenant will not be breached. The Directors believe that the Retained Group would be able to secure such an amendment or waiver, which would be both consistent with past practice and the Directors' reasonable expectation of the commercial interests of the Retained Group and its lenders. As at the date of this document, the Group's management has not approached the relevant lenders to discuss an amendment to or waiver of the 31 December 2020 RBL Gearing Covenant. The Directors note that agreeing an amendment or waiver of the RBL Gearing Covenant would require the approval of the relevant majority of lenders under the RBL Facility. This action is therefore outside the control of the Retained Group.

March 2021 Liquidity Forecast Test, timing and action plan

The Group's working capital projections forecast a potential liquidity shortfall during the 18-month period relevant to the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination. This potential liquidity shortfall in relation to the Group's financial commitments of approximately US$600 million in the reasonable worst case scenario, and approximately US$130 million in the base case scenario, is first forecasted to arise in April 2022 which is within the 18-month testing period from April 2021 to September 2022 inclusive that is relevant to determining whether the Company will pass the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination. If the Company is unable to demonstrate to the reasonable satisfaction of the relevant majority of its lenders under the RBL Facility that it has, or will have, sufficient funds available to meet the Group's financial commitments for the 18-month testing period from April 2021 to September 2022 inclusive (for example, because the lenders under the RBL Facility do not take into account the potential positive impact of the mitigating actions described below), and the Company is unable to cure the forecast liquidity shortfall within 90 days following the date on which it becomes aware that it has not passed the Liquidity Forecast Test, there will be an event of default under the RBL Facility by the end of June 2021.

The Directors note that passing the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination would require satisfying the relevant majority of lenders in relation to the Retained Group's liquidity. This is therefore outside the control of the Retained Group. As at the date of this document, the Group's management has not approached the relevant lenders in respect of the March 2021 RBL Facility redetermination.

The Group's management expects that it will investigate refinancing either or both of the Convertible Bonds due in July 2021 and the 2022 Senior Notes due in April 2022 to address the forecasted liquidity shortfall in April 2022. Such refinancing would be both consistent with past practice and the Directors' reasonable expectation of the commercial interests of the Retained Group and its creditors. As at the date of this document, the Group's management has not undertaken any steps in respect of refinancing either the Convertible Bonds due in July 2021 or the 2022 Senior Notes due in April 2022. The Directors note that any debt refinancing is outside the control of the Retained Group and therefore the Directors cannot be confident that any such refinancing could be delivered, or sufficiently progressed, such that the lenders of the RBL Facility would take it into account in respect of the Liquidity Forecast Test at the March 2021 RBL Facility redetermination.

The Group's management also continues to evaluate strategic opportunities and engage in discussions with third parties with a view to raising in excess of US$1 billion proceeds from portfolio management, of which the proceeds from the Transaction would be a significant part. For example, the Group is in discussions with third parties with respect to farming down its interests in the South Lokichar onshore development in Kenya. There can be no assurance that it will be possible to make any such disposals and it is not possible at this stage to give an indication of the potential proceeds which the South Lokichar onshore development or any other assets may realise. Accordingly, the Directors cannot be confident that these disposals can be achieved.

In addition, the Group's management is considering taking one or more of the following actions which the Group's management believes could be progressed sufficiently by the end of March 2021 such that the Retained Group would be able to pass the Liquidity Forecast Test at the March 2021 RBL Facility redetermination:

(a) independently of the amendment or waiver expected to be sought in respect of the potential breach of the RBL Gearing Covenant for the 12-month testing period ending 31 December 2020, securing a new liquidity facility from banks or capital markets investors. While the Directors believe that the Group has strong relationships with its lending banks and a track record of accessing capital markets, there can be no assurance that the Retained Group's lending banks or any other investor would agree to provide such a facility. In addition, the Directors note that, in light of the increased regulatory oversight and requirements under which banks and investors operate and the volatility of oil prices, there has been a reduction in certain banks' and investors' willingness and ability to lend to or invest in entities in the oil and gas industry. Accordingly, the Directors cannot be confident that the Retained Group will be able to secure or obtain additional financing on commercially acceptable terms, or at all;

(b) as part of the March 2021 RBL Redetermination, seeking to agree more beneficial technical and/or economic assumptions with its lenders or seeking to amend the commercial terms of the RBL Facility in order to increase debt capacity. The Directors note that these actions would require the approval of the relevant majority of lenders under the RBL Facility and are therefore outside of the control of the Retained Group. As such, the Directors cannot be confident that this could be achieved;

(c) initiating a further rationalisation of its cost base (in addition to measures already implemented since December 2019) through a further reduction of general and administrative costs. The Directors are reasonably confident that a further reduction of approximately US$25 million per annum can be achieved from 2021 onwards; and

(d) initiating cuts to discretionary capital investment (in addition to measures already implemented since December 2019 and, for example, by focussing on maintenance of producing fields only and substantially reducing investment in development, exploration and appraisal activities) and deferring decommissioning expenditure. The Directors note that initiating cuts to discretionary capital investment and deferring decommissioning expenditure: (i) may require approval from third parties including its commercial partners and there can be no assurances that these approvals will be obtained; and (ii) are dependent to an extent upon the Retained Group's ability to execute strategic opportunities in relation to asset disposals and there can be no assurance that it will be possible to make any such disposals. Accordingly, the Directors cannot quantify any savings that may arise out of such measures or be confident that any such measures will be successful.

While the Directors would consider the above actions in parallel, the Directors cannot be certain that these mitigating actions will be capable of addressing the forecasted liquidity shortfall in the time available, or at all.

Event of default

The potential events of default in respect of the 31 December 2020 RBL Gearing Covenant and/or the March 2021 RBL Facility redetermination would arise concurrently (i.e. by mid to end June 2021).

Any event of default under the RBL Facility as described above would allow the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights. This would in turn trigger creditors' rights to call cross-defaults under the other financing arrangements of the Retained Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes). Enforcement action taken by the relevant trustees on instruction of the bondholders could result in the entirety of the Retained Group's borrowings potentially becoming immediately repayable by:

(a) around mid-June 2021 (in the event of a breach of the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020); and

(b) around the end of June 2021 (in the event that the Retained Group does not pass the Liquidity Forecast Test at the March 2021 RBL Facility redetermination).

The amount outstanding under the Retained Group's RBL Facility which could be required to be repaid following an event of default under the RBL Facility as described above was US$1.505 billion as at 31 May

2020. The amount repayable should the Retained Group's creditors exercise their right to trigger a cross-default under the Retained Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Retained Group's borrowings, including the amount outstanding under the Retained Group's RBL Facility, is immediately repayable, was US$3.255 billion as at 31 May 2020. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

Implications

If a breach of the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020 were to occur or the Retained Group were not to pass the Liquidity Forecast Test at the March 2021 RBL Facility redetermination, and the Retained Group were unable to negotiate amendments or waivers to its covenants, the Retained Group might have to enter into insolvency proceedings and counterparties to material contracts might seek to exercise termination rights under those contracts. In such circumstances, the ability of the Retained Group to continue trading would depend upon the Retained Group being able to negotiate a refinancing proposal with its creditors and, if necessary, that proposal being approved by Shareholders. Whilst the Board would seek to negotiate such a refinancing proposal with its creditors, there is no certainty that the creditors would engage with the Board in those circumstances. There would therefore be a significant risk of the Retained Group entering into insolvency proceedings, which the Directors consider would likely result in limited or no value being returned to Shareholders.

The Retained Group will continue to operate with a significant level of Net Debt which may materially and adversely affect the Retained Group's business, liquidity, financial condition and prospects

The oil and gas industry is capital intensive and the Group expects to fund ongoing capital and operational expenditure from a combination of cash from operations, monetisation of assets, debt facilities and debt and equity capital market transactions. Following Completion, the Retained Group will continue to operate with a significant level of Net Debt which may constrain the scale of its future investments on development, exploration and appraisal activities which could limit the Company's longer-term growth prospects (that is, more than 12 months from the date of this document). On a pro forma basis, the Retained Group's Net Debt as at 31 December 2019, if Completion had occurred on that date, would have been approximately US$2.3 billion and the Retained Group's Gearing would have been approximately 1.7 times Net Debt/Adjusted EBITDAX. The financial information set out in this paragraph is unaudited and is calculated as described in Note 9 of the unaudited pro forma financial information contained in Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document.

The level of the Retained Group's Net Debt, whether pending or following Completion, could have important consequences for its business, financial condition, results of operations and/or prospects. For example, the Retained Group may be unable to undertake certain operations which it considers would be beneficial to the Retained Group if such operations require increased or unbudgeted capital or operational expenditure. In addition, the Retained Group may not be able to react to changes in the competitive environment or its industry. The Retained Group must ensure compliance with the financial covenants set by its lenders when managing its Net Debt and financial resources and when planning for, or reacting to, changes in capital or operational expenditure in its business, the competitive environment and its industry. If, following an evaluation of the Retained Group's financial position against such covenants, the Retained Group determines it is unable to undertake certain operations which it considers would be beneficial to the Retained Group without breaching such covenants, the Group's business, financial condition, longer-term liquidity, results of operations and/or prospects may be materially and adversely affected. Whilst the Group has been able to negotiate amendments to the terms of such financial covenants in the past, there can be no assurance that the Retained Group will be able to do so in the future on commercially acceptable terms, or at all. In addition, any failure to comply with any covenant may materially and adversely affect the Retained Group's business, financial condition, longer-term liquidity, results of operations and/or prospects.

In light of the increased regulatory oversight and requirements under which banks and investors operate and the volatility of oil prices, there has been a reduction in certain banks' and investors' willingness and ability to lend to or invest in entities in the oil and gas industry. Accordingly, over the longer-term (that is, more than 12 months from the date of this document), there is a risk that the Retained Group may not be able to refinance its existing or future financial indebtedness or obtain additional debt finance on commercially acceptable terms, or at all. If refinancing or additional debt is not available to the Retained Group on commercially acceptable terms, or at all, this may materially and adversely affect the Retained Group's business, financial condition, longer-term liquidity, results of operations and/or prospects.

The Retained Group may be required to dedicate a significant portion of its cash flow to servicing the Retained Group's debt obligations, thereby reducing the funds available for operations and future business opportunities. The Retained Group's level of indebtedness makes it vulnerable to general adverse economic conditions (including in relation to COVID-19 and current market uncertainty) and so place the Retained Group at a commercial disadvantage to competitors who are less indebted.

It is the Company's intention to refinance the RBL Facility prior to its final maturity in 2024. If the RBL Facility cannot be successfully refinanced, this may materially and adversely affect the Retained Group's business, financial condition, longer-term liquidity, results of operations and/or prospects.

The Retained Group's operations will be less diversified

Following Completion, the Retained Group will no longer be able to benefit from the potential future production from the Lake Albert Development Project. As a result, the Retained Group's production will continue to be concentrated on its West Africa production, and in particular on the Group's Ghana assets.

There can be no assurance that a final investment decision will be taken in the near future, if at all, on the Group's South Lokichar Basin onshore Kenya project or that the Retained Group's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and gas, and therefore there can be no assurance that there will be a reduction in concentration in the Group's production on its Ghanaian assets.

The long-term concentration of the Group's production on its Ghanaian assets may in turn make the Group more vulnerable in the future to any political, economic, legal, regulatory and social uncertainties in Ghana, to which it would otherwise have been proportionally less exposed had its production included production arising from the Interests.

The Retained Group's business reputation and brand may be adversely affected as a result of its operations being less diversified and the sale of the entirety of its Ugandan assets. The Group's (and following Completion, the Retained Group's) reputation is important to its business for reasons including, but not limited to, finding commercial partners for business ventures, securing licences or permits with governments, procuring offtake contracts, attracting contractors and employees and negotiating favourable terms with suppliers. As a less diversified business, governments and business partners, particularly in Africa, may consider that the Retained Group has a reduced network and fewer commercial connections and as such is less attractive as an investor and partner.

The reduction in size of the Retained Group may make it more difficult to attract and retain key employees

The success of the Retained Group depends on the efforts, abilities, experience and expertise of its senior management teams, and on recruiting, retaining, motivating and developing highly skilled and competent people at all levels of the organisation. The reduction in size, geographical footprint and diversification of the Retained Group, as well as the relinquishment following Completion of the Transaction of operatorship of a large asset in a new oil province (resulting in the operatorship of the Ghanaian assets being the Retained Group's sole operatorship of producing assets), may make it more difficult to attract and retain talented employees which may have an adverse effect on the Retained Group's business, financial condition, results of operations and/or prospects.

The reduction in size of the Retained Group may make it more difficult or more expensive to secure funding

The reduction in size and diversification of the Retained Group may make raising funding more difficult or more expensive as the Retained Group will not be able to use the Interests as collateral for future financing initiatives. This may in turn result in the liquidity of the Group becoming insufficient and lead the Board to decide to seek additional sources of liquidity which may result in a significant increase in the Group's financing costs.

The market price of the Tullow Shares may go down as well as up

Shareholders should be aware that the value of an investment in the Company may go down as well as up and can be highly volatile. The price at which the Tullow Shares may be quoted and the price which investors may realise for their Tullow Shares will be influenced by a large number of factors, some specific to the Retained Group and its operations and some which may affect the industry as a whole.

The sentiments of the stock market regarding the Transaction, in particular whether the stock market considers whether the Group has secured a fair value for the Interests or agreed the Transaction at an appropriate stage in the lifecycle of the Interests, will be one such factor and this, together with other factors including the likelihood of Completion occurring, actual or anticipated fluctuations in the financial performance of the

Retained Group and its competitors, market fluctuations and legislative or regulatory changes in the industry or generally those affecting consumers, could lead to the market price of the Tullow Shares going up or down. Such sentiments may vary between the date of this document and Completion depending on how certain pre-Completion events progress, such as obtaining the Minister Consents and approval from Tullow Shareholders and entering into the Tax Agreement with the Government of Uganda and the URA.

If the Group (and following Completion, the Retained Group) is unable to replace the commercial reserves that it produces, its reserves and revenues will decline

The future success of the Group (and following Completion, the Retained Group) depends on its ability to find and develop or acquire additional commercial reserves that are economically recoverable. While well supervision and effective maintenance operations can contribute to sustaining production rates over time, the Group (and following Completion, the Retained Group) is required to undertake exploration, appraisal and development activities in order to replace reserves which are depleted by production.

Completion of the Transaction will result in the reduction of the Group's contingent resources. The estimated 2C resources of the Uganda assets net to the Company are 476.1 mmboe, as described in the mineral expert's report prepared by TRACS and set out in Part VII (*Mineral Expert's Report*). Completion of the Transaction will reduce the Group's 2C resources accordingly.

A final investment decision on the Lake Albert Development Project during the Group's ownership would be expected to trigger the start of conversion of these resources into commercial reserves, increasing and replenishing the Group's commercial reserves.

Whilst the Group (and following Completion, the Retained Group) may seek to develop or acquire additional assets containing commercial reserves, it may not be able to find, develop or acquire suitable additional reserves on commercially acceptable terms or at all, which could result in depletion of the Group's reserves which in turn could materially and adversely affect the business, financial condition, results of operations and/or prospects of the Group (and following Completion, the Retained Group). This may negatively impact the Group's future production, which in turn may negatively affect the Group's free cash flow.

In addition, with a lower reserve base, the Group may not be able to attract funding to the level required to support its capital investment programme, which may reduce or delay some of the Group's capital expenditure plans and may further adversely impact the Group's future production and the Group's reserves, as well as the Group's future prospects with respect to its development projects and its new ventures activities.

The Group (and following Completion, the Retained Group) may be adversely affected by changes to tax legislation or its interpretation or increases in effective tax rates

The Group's (and following Completion, the Retained Group's) tax rate and other tax costs, including its effective tax rate, value added tax ("VAT") and capital gains tax ("CGT"), may be affected by changes in tax laws or interpretations of tax laws in any jurisdiction and in any financial year will reflect a variety of factors that may not be present in succeeding financial years. As a result, the Group's (and following Completion, the Retained Group's) tax rate and other tax costs may increase in future periods, which could have a material adverse effect on the business, financial condition, results of operations and/or prospects of the Group (and following Completion, the Retained Group) and, specifically, their net income, cash flow and earnings may decrease.

Tax regimes in certain jurisdictions can be subject to differing interpretations (particularly in light of the contractual provisions which the Group and its commercial partners may have agreed with host governments, including in connection with the Transaction) and tax rules and agreements in any jurisdiction are subject to legislative change and changes in administrative and regulatory interpretation. The interpretation by the Group's (and following Completion, the Retained Group's) relevant subsidiaries of applicable tax law and agreements as applied to their transactions and activities (including the Transaction) may not coincide with that of the relevant tax authorities. As a result, transactions may be challenged by tax authorities (whether on disclosure of such transactions or at a later date) and any of the Group's profits from activities in those jurisdictions may be subject to additional tax or additional unexpected transactional taxes (e.g., stamp duty, VAT, CGT or withholding tax) or other consequences may arise, which, in each case, could result in significant legal proceedings and additional taxes, penalties and interest. There can be no guarantee that any tax disputes will be resolved in the Group's (or following Completion, the Retained Group's) favour, and any of these could have a material adverse impact on the business, financial condition, results of operations and/or prospects of the Group (and following Completion, the Retained Group). In the past, the Group has received claims for tax payable that, following a negotiated settlement, have been reduced to a material extent. However, there can be no assurance that the Group (and following Completion, the Retained Group) will be able to negotiate an appropriate settlement in the future or that a tax authority will not enforce the original claim for tax payable which could materially adversely affect the business, financial condition, results of operations and/or prospects of the Group (and following Completion, the Retained Group).

PART III—FINANCIAL INFORMATION ON THE INTERESTS

The following historical financial information relating to the Interests has been extracted without material adjustment from the consolidation schedules and supporting analysis that underlie the audited consolidated financial information of Tullow for the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019.

The financial information in this Part III (*Financial Information on the Interests*) does not constitute statutory accounts within the meaning of Section 434 of the Companies Act 2006. The consolidated statutory accounts for the Company in respect of the financial years ended 31 December 2017, 31 December 2018 and 31 December 2019 have been delivered to the Registrar of Companies. The auditor's reports in respect of the statutory accounts for each of these three financial years were unqualified and did not contain statements under Section 498(2) or (3) of the Companies Act 2006.

Deloitte were the auditors of the Tullow Group in respect of the three financial years to 31 December 2019.

The financial information in this Part III (*Financial Information on the Interests*) has been prepared on a basis consistent with the accounting policies adopted in the Group's latest annual accounts, being those for the year ended 31 December 2019.

Shareholders should read the whole of this document and not rely solely on the summarised financial information in this Part III (*Financial Information on the Interests*).

Financial information (unaudited)

Income statement

	Year ended 31 December 2017	Year ended 31 December 2018	Year ended 31 December 2019
	US$m	US$m	US$m
Sales revenue	—	—	—
Cost of sales	—	—	—
Gross profit	—	—	—
Administrative expenses	(0.4)	(0.5)	6.4
Exploration costs written off	—	(74.5)	(535.2)
Operating loss	**(0.4)**	**(75.0)**	**(528.8)**
Finance revenue	—	0.1	0.4
Finance costs	(1.2)	(0.4)	—
Loss from continuing activities before tax	**(1.6)**	**(75.3)**	**(528.4)**
Income tax expense	—	—	—
Loss for the year from continuing activities	**(1.6)**	**(75.3)**	**(528.4)**

Net assets statement

	As at 31 December 2019
	US$m
Non-current assets	
Intangible exploration and evaluation assets	960.0
Property, plant and equipment	—
Other non-current assets	8.7
	968.7
Current assets	
Inventories	3.3
Trade receivables	0.3
Other current assets	19.9
Cash	—
	23.5
Total assets	**992.2**
Current liabilities	
Trade and other payables	(28.8)
	(28.8)
Net current liabilities	(5.3)
Non-current liabilities	
Trade and other payables	—
	—
Total liabilities	**(28.8)**
Net assets	**963.4**

PART IV—UNAUDITED PRO FORMA FINANCIAL INFORMATION OF THE RETAINED GROUP

1. Unaudited pro forma financial information of the Retained Group

Set out below is the consolidated pro forma statement of net assets of the Retained Group as at 31 December 2019 (the "pro forma financial information"). The pro forma financial information is unaudited.

The unaudited consolidated pro forma statement of net assets of the Retained Group has been prepared to illustrate the effect of the Transaction on the consolidated net assets of the Group as at 31 December 2019 as if the Transaction had completed on that date.

The pro forma financial information has been prepared on the basis set out in the notes below and is based on the audited statement of financial position of the Group for the year ended 31 December 2019 and, in respect of the Interests, has been extracted without material adjustment from the consolidation schedules and supporting analysis that underlie the audited consolidated financial information of the Group for the financial year ended 31 December 2019.

The pro forma financial information has been prepared for illustrative purposes only and, because of its nature, addresses a hypothetical situation and therefore does not represent the Retained Group's actual financial position or results.

Shareholders should read the whole of this document, including the risk factors in Part II (*Risk Factors*) of this document, and not rely solely on the summarised financial information in this Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*). In particular, there can be no assurance that any element of deferred and/or contingent consideration will become payable following Completion of the Transaction—see the Section entitled "Deferred and contingent consideration" in Part II (*Risk Factors*) of this document.

Furthermore, the unaudited pro forma financial information set out in this Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) does not constitute statutory accounts within the meaning of section 434 of the Companies Act 2006.

Deloitte's report on the unaudited pro forma financial information is set out in Section 2 of this Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*).

Notes	Group net assets as at 31 December 2019 US$m *1*	Disposal of net assets of the Interests as at 31 December 2019 US$m *2*	Transaction adjustments US$m *3, 4, 5*	Unaudited pro forma net assets of the Retained Group as at 31 December 2019 US$m *6, 7, 8, 9*
Non-current assets				
Intangible exploration and evaluation assets	1,764.4	(960.0)	—	804.4
Property, plant and equipment	3,891.7	—	—	3,891.7
Other non-current assets	623.2	(8.7)	—	614.5
Derivative financial instruments	3.1	—	—	3.1
Deferred tax assets	517.5	—	—	517.5
	6,799.9	(968.7)		5,831.2
Current assets				
Inventories	191.5	(3.3)	—	188.2
Trade receivables	38.7	(0.3)	—	38.4
Other current assets	928.7	(19.9)	75.0	983.8
Current tax assets	42.9	—	—	42.9
Derivative financial instruments	0.7	—	—	0.7
Cash and cash equivalents	288.8	—	486.8	775.6
	1,491.3	(23.5)	561.8	2,029.6
Total assets	**8,291.2**	**(992.2)**	**561.8**	**7,860.8**
Current liabilities				
Trade and other payables	(1,127.6)	28.8	—	(1,098.8)
Provisions	(172.8)	—	—	(172.8)
Current tax liabilities	(159.6)	—	—	(159.6)
Derivative financial instruments	(14.8)	—	—	(14.8)
	(1,474.8)	28.8	—	(1,446.0)
Net current assets	**16.5**	**5.3**	**561.8**	**583.6**
Non-current liabilities				
Trade and other payables	(1,212.9)	—	—	(1,212.9)
Borrowings	(3,071.7)	—	—	(3,071.7)
Provisions	(753.6)	—	—	(753.6)
Deferred tax liabilities	(793.4)	—	—	(793.4)
Derivative financial instruments	(1.2)	—	—	(1.2)
	(5,832.8)	—	—	(5,832.8)
Total liabilities	**(7,307.6)**	**28.8**	**—**	**(7,278.8)**
Net assets	**983.6**	**(963.4)**	**561.8**	**582.0**

1. The net assets of Tullow Oil plc as at 31 December 2019 have been extracted without material adjustment from the audited consolidated financial statements of Tullow for the financial year ended 31 December 2019.

2. This adjustment removes assets and liabilities of the Interests as at 31 December 2019. The figures have been extracted without material adjustment from the consolidation schedules and supporting analysis that underlie the consolidated financial statements of Tullow at that date.

3. The Transaction adjustments reflect the estimated net cash proceeds for the Interests, which consist of US$500 million payable at Completion, and US$75 million deferred consideration payable following the final investment decision for the Upstream Segment and the Midstream Segment, less assumed Transaction costs related to the Interests of US$7.1 million and other consideration due on Completion from past transactions of US$6.1 million. The consideration is subject to certain financial adjustments under the Sale and Purchase Agreement (which are customary under sale and purchase agreements). No adjustment has been made in the pro forma financial information to reflect these customary financial adjustments as any such adjustment will not be determined until Completion. See the Section 1.3 of Part V (*Summary of the Principal Terms of the Transaction*) of this document.

4. The contingent consideration valuation will be dependent on oil price assumptions at the time of Completion (and subsequently) and US$nil value has been assumed for the purposes of this unaudited consolidated pro forma statement of net assets given this uncertainty. See the Section entitled "Deferred and contingent consideration" in Part II (*Risk Factors*) of this document.

   The pro forma information includes the US$75 million deferred consideration which is dependent on the final investment decision for the Upstream Segment and the Midstream Segment. See the Section entitled "Deferred and contingent consideration" in Part II (*Risk Factors*) of this document.

5. No tax effect has been recognised as a result of the Transaction, in line with the anticipated terms of the Tax Agreement and terms of the Sale and Purchase Agreement.

6. No account has been taken of any trading or results of the Company or the Interests since 31 December 2019.

7. This unaudited consolidated pro forma statement of net assets has been prepared in accordance with the requirements of paragraphs 1 to 3 of Annex 20 of the PR Regulation and has been prepared in a manner consistent with the accounting policies of the Company for the financial year ended 31 December 2019.

8. This unaudited consolidated pro forma statement of net assets does not constitute financial statements within the meaning of section 434 of the Companies Act 2006.

9. Net Debt and Gearing of the Retained Group as at 31 December 2019 on a pro forma basis, adjusted only for the estimated cash proceeds for the Interests at Completion as described in Note 3 above, are calculated as follows:

   Calculation of unaudited pro forma Net Debt of the Retained Group as at 31 December 2019

Net Debt for the Group as at 31 December 2019 (US$m)	2,805.5
Estimated net cash proceeds for the Interests at Completion (as described in Note 3 above) (US$m)	(486.8)
Unaudited pro forma Net Debt of the Retained Group as at 31 December 2019 (US$m)	2,318.7

   Calculation of Net Debt/Adjusted EBITDAX Gearing (on an unaudited pro forma basis) of the Retained Group as at 31 December 2019

Net Debt (US$m)	2,318.7
Adjusted EBITDAX (US$m)	1,397.5
Gearing	1.7

   Tables of reconciliation of Net Debt, Adjusted EBITDAX and Gearing in respect of the Group as at 31 December 2019 are set out on page 6.

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5 The North Colonnade
Canary Wharf
London
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J.P. Morgan Securities plc
(which conducts its UK investment banking business as J.P. Morgan Cazenove)
25 Bank Street
London
E14 5JP

18 June 2020

Dear Sirs/Mesdames,

Tullow Oil plc (the "Company")

We report on the pro forma financial information of the Retained Group (the "Pro forma financial information") set out in Part IV of the Class 1 circular dated 18 June 2020 (the "Circular"), which has been prepared on the basis described in the notes 1-9, for illustrative purposes only, to provide information about how the transaction might have affected the financial information presented on the basis of the accounting policies adopted by the Company in preparing the financial statements for the period ended 31 December 2019. This report is required by the Commission delegated regulation (EU) 2019/980 (the "Prospectus Delegated Regulation") as applied by Listing Rule 13.3.3R and is given for the purpose of complying with that requirement and for no other purpose.

Responsibilities

It is the responsibility of the directors of the Company (the "Directors") to prepare the Pro forma financial information in accordance with Annex 20 sections 1 and 2 of the Prospectus Delegated Regulation as applied by Listing Rule 13.3.3R.

It is our responsibility to form an opinion as to the proper compilation of the Pro forma financial information and to report that opinion to you in accordance with Annex 20 section 3 of the Prospectus Delegated Regulation as applied by Listing Rule 13.3.3R.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to holders of ordinary shares of the Company as a result of the inclusion of this report in the Circular, to the fullest extent permitted by law we do not assume any responsibility and will not accept any liability to any other person for any loss suffered by any such other person as a result of, arising out of, or in connection with this report or our statement, required by and given solely for the purposes of complying with Listing Rule 13.4.1R (6), consenting to its inclusion in the Circular.

In providing this opinion we are not updating or refreshing any reports or opinions previously made by us on any financial information used in the compilation of the Pro forma financial information, nor do we accept responsibility for such reports or opinions beyond that owed to those to whom those reports or opinions were addressed by us at the dates of their issue.

Basis of Opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board in the United Kingdom. The work that we performed for the purpose of making this report, which involved no independent examination of any of the underlying financial information, consisted primarily of comparing the unadjusted financial information with the source documents, considering the evidence supporting the adjustments and discussing the Pro forma financial information with the Directors.

We planned and performed our work so as to obtain the information and explanations we considered necessary in order to provide us with reasonable assurance that the Pro forma financial information has been properly compiled on the basis stated and that such basis is consistent with the accounting policies of the Company.

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

Opinion

In our opinion:

(a) the Pro forma financial information has been properly compiled on the basis stated; and

(b) such basis is consistent with the accounting policies of the Company.

Yours faithfully

Deloitte LLP

PART V—SUMMARY OF THE PRINCIPAL TERMS OF THE TRANSACTION

1. Summary of the principal terms of the Sale and Purchase Agreement

1.1 Overview

Tullow Uganda entered into the Sale and Purchase Agreement on 23 April 2020, under which it has conditionally agreed to transfer the Interests to Total Uganda for cash consideration and additional deferred and contingent consideration with effect from the Effective Date, being Tullow Uganda's entire interests in: (i) the production sharing agreements for each of Block 1, 1A, 2 and 3A in Uganda and the licences and certain other contracts related thereto; and (ii) the proposed EACOP System.

1.2 Conditions

Completion of the Sale and Purchase Agreement is conditional upon the satisfaction of certain conditions, including:

(a) the URA and Government of Uganda entering into the Tax Agreement that reflects the agreed principles of the tax treatment of the Transaction;

(b) the Company having obtained the approval of its Shareholders as required under the Listing Rules; and

(c) the Minister Consents.

Completion was also subject to CNOOC Uganda having declined to exercise its pre-emption rights under each of the Joint Operating Agreements or, where CNOOC Uganda had exercised its pre-emption rights with respect to the Upstream Segment, Tullow Uganda and Total Uganda (each acting reasonably) having agreed amendments to the Sale and Purchase Agreement and other arrangements to reflect the exercise of such pre-emption rights. On 26 May 2020, CNOOC Uganda gave notice that it did not wish to exercise its pre-emption rights.

The Company has undertaken to use all reasonable endeavours to procure that Shareholder approval is obtained and the parties have undertaken to use: (i) all reasonable endeavours to procure satisfaction of the condition relating to entry into the Tax Agreement (as described in (a) above); and (ii) reasonable endeavours to procure each of the other conditions is satisfied as soon as possible after the signing date of the Sale and Purchase Agreement and in any event by 23 October 2020 (unless the parties mutually agree to extend such date).

1.3 Consideration

Under the Transaction, Total Uganda will pay US$500 million at Completion (subject to customary adjustments) and US$75 million following the final investment decision for the Upstream Segment and the Midstream Segment. Additional annual contingent consideration may be payable by Total on upstream revenues from the Interests (reducing to 28.3334 per cent. following the exercise by UNOC of its back-in rights) once production commences, at an amount equal to 1.25 per cent. (net of tax) if the average annual Brent price is greater than US$62/bbl or 2.5 per cent. (net of tax) if the average annual Brent price is greater than US$70/bbl. No payment will be due in respect of the contingent consideration if the average annual Brent price in respect of the relevant year is less than or equal to US$62/bbl. Total Uganda will also reimburse Tullow Uganda for joint venture costs incurred and paid by Tullow Uganda from the Effective Date to Completion in respect of the Interests.

1.4 Undertakings, warranties and indemnities

The Group has agreed, between the date of execution of the Sale and Purchase Agreement and Completion, to: (i) carry on the operation of Block 2 in all material respects in the ordinary and usual course of business and comply with previously agreed decisions of the operating committees and joint management committees; (ii) consult with Total Uganda with regard to any material decisions relating to the Interests of which it becomes aware; and (iii) promptly inform Total Uganda of any and all matters (not of a routine or minor nature) of which it becomes aware relating to Block 2 and Block 3A, including the making of any cash call under any Joint Operating Agreement relating to the Interests, the approval of any authorisation for expenditure, the receipt of the operator's billing statements and invoices and the adoption or amendment to any work programmes and budgets.

The Group has provided Total Uganda with customary warranties in relation to the Transaction and the Company has agreed to deliver a guarantee in support of Tullow Uganda Limited's and Tullow Uganda Operations Pty Limited's obligations under the Sale and Purchase Agreement.

The Sale and Purchase Agreement includes customary pre- and post-Effective Date indemnities to reflect that economic ownership of the Interests transfers to Total Uganda from the Effective Date. In summary:

(a) Tullow Uganda indemnifies Total Uganda and any other member of the Total group that has provided a guarantee in favour of the Government of Uganda with respect to the Interests for: (i) all liabilities, losses, costs and expenses incurred by Total Uganda in relation to the Interests in respect of the period prior to the Effective Date; and (ii) any benefits that may accrue to Tullow Uganda in relation to the Interests in respect of the period on and from the Effective Date; and

(b) Total Uganda indemnifies Tullow Uganda and any other Group companies that have provided guarantees or indemnities with respect to the Interests for: (i) all liabilities, losses, costs and expenses incurred in relation to the Interests in respect of the period on or after the Effective Date; and (ii) any benefits that may accrue to Total Uganda in relation to the Interests in respect of the period prior to the Effective Date,

in each case as determined on an accruals basis.

Total Uganda has agreed to indemnify Tullow Uganda with respect to all environmental and decommissioning liabilities, losses, costs and expenses that arise in relation to Blocks 1 and 1A (which are operated by Total Uganda) regardless of whether such liabilities and losses arise before or after the Effective Date.

Tullow Uganda has provided Total Uganda with an indemnity in respect of all claims, liabilities, losses, damages, costs and expenses (including penalties, charges, fines and interest and legal fees and expenses) in relation to taxes imposed by Uganda in respect of any period ending prior to the Effective Date which relate to the Interests, save to the extent taken into account in the completion adjustments or covered by the warranties given by Tullow. Total Uganda has provided Tullow Uganda with an equivalent indemnity in respect of any period commencing on or after the Effective Date, save that Ugandan tax (if any) payable on or in respect of the Transaction other than as provided for by the duly executed Tax Agreement shall be shared equally by the parties.

1.5 Transfer of employees

In respect of employees, the Sale and Purchase Agreement provides that Tullow Uganda shall use its reasonable efforts to make its employees available for interview with Total Uganda within 30 business days from signing of the Sale and Purchase Agreement. Total Uganda is required to notify the Company which of those employees shall become employees of Total Uganda from Completion. The Company has agreed customary indemnities in respect of: (i) any costs incurred by Total Uganda in connection with any employees who do not transfer to Total Uganda; and (ii) certain costs that could be incurred by Total Uganda in connection with any employees who do transfer, save to the extent that any such costs are recharged in accordance with the Joint Operating Agreements.

1.6 Limitations of liabilities

Each of Tullow Uganda Limited's and Tullow Uganda Operations Pty Ltd.'s liability under the Sale and Purchase Agreement for warranty claims is capped at:

(a) 100 per cent. of the total consideration received from Total Uganda in respect of fundamental warranty claims relating to title to the Interests and capacity of Tullow Uganda to enter into the Transaction; and

(b) 40 per cent. of the total consideration received from Total Uganda in respect of all other warranty claims,

as such consideration is apportioned to each of Tullow Uganda Limited and Tullow Uganda Operations Pty Ltd.

The Sale and Purchase Agreement includes customary financial threshold and *de minimis* limitations on Total Uganda's ability to bring claims under the warranties given by Tullow Uganda. Each individual warranty claim brought by Total Uganda must exceed US$750,000 (the *de minimis* limitation) but Tullow Uganda will only be liable once a threshold of US$7.5 million is exceeded for all warranty claims that satisfy the *de minimis* limitation. The Sale and Purchase Agreement also imposes time limits on Total Uganda's ability to bring warranty claims against Tullow Uganda which vary depending on the type of warranty.

1.7 Termination

Total Uganda has the right to terminate the Sale and Purchase Agreement between signing and Completion in certain circumstances if there is a material adverse event, which includes: (i) a breach of fundamental warranty by Tullow Uganda; (ii) any action or claim by a third party seeking to restrain or materially alter the transactions contemplated by the Sale and Purchase Agreement; or (iii) an event or series of related events occurring in Uganda, where each of (i), (ii) or (iii) results in a reduction in the value of the Interests in excess of US$86.25 million (and in each case certain macro-events such as changes in hydrocarbon prices, market conditions and COVID-19 are excluded); or (iv) an insolvency event in respect of the Company, Tullow Uganda or any holding company of Tullow Uganda.

Tullow Uganda and Total Uganda each has the right to terminate the Sale and Purchase Agreement between signing and Completion if: (i) the URA or any other Ugandan Government Authority challenges or revokes or purports to revoke or threatens to revoke the Tax Agreement once entered into; (ii) there is a breach of specific warranties and undertakings given in respect of anti-bribery and corruption; or (iii) if any of the conditions precedent to Completion are not satisfied or waived by 23 October 2020 (unless the parties mutually agree to extend such date).

1.8 Governing Law and jurisdiction

The Sale and Purchase Agreement is governed by English law. The parties have agreed that any disputes shall be finally settled under the Rules of Arbitration of the International Chamber of Commerce in force at the date of applying for arbitration by three arbitrators appointed in accordance with such rules, in Geneva, Switzerland and in the English language. The chairman of the arbitral panel shall not be a national of England or France.

2. Summary of the principal terms of the other Transaction Agreements

2.1 Tullow Guarantee in respect of the Interests

The Company has provided a customary parent company guarantee in respect of the obligations of Tullow Uganda under the Sale and Purchase Agreement. The Company's aggregate liability under the guarantee shall not exceed the liability of Tullow Uganda under the Sale and Purchase Agreement.

2.2 Total Guarantee in respect of the Interests

Total Holdings has provided a customary guarantee in respect of Total Uganda's obligations under the Sale and Purchase Agreement. Total Holdings' aggregate liability under the guarantee shall not exceed the liability of Total Uganda under the Sale and Purchase Agreement.

2.3 Tax Agreement

Tullow Uganda, Total Uganda, the URA and the Government of Uganda (acting through the Ministry of Energy and Mineral Development and the Ministry of Finance, Planning and Economic Development) have discussed and agreed the principles of the tax treatment of the Transaction. In light of those discussions, the Transaction is expected to be subject to the following Ugandan tax treatment:

(a) a capital gain of US$48.715 million will arise on Completion, subject to Ugandan tax on capital gains at 30 per cent., being US$14.61 million, which will be remitted by Total Uganda on behalf of Tullow Uganda; and

(b) any contingent consideration paid to Tullow will represent a capital gain in relation to the Transaction, subject to Ugandan tax on capital gains at 30 per cent. This tax will also be remitted by Total Uganda on behalf of Tullow Uganda.

Tullow Uganda and Total Uganda intend to enter into the Tax Agreement with the Government of Uganda and the URA to reflect these principles.

PART VI—ADDITIONAL INFORMATION

1. RESPONSIBILITY

The Company and the Directors, whose names appear on page 47 of this document, accept responsibility for the information contained in this document. To the best of the knowledge and belief of the Company and the Directors (who have taken all reasonable care to ensure that such is the case) the information contained in this document is in accordance with the facts and does not omit anything likely to affect the import of such information.

2. COMPANY INFORMATION

The Company was incorporated and registered in England and Wales on 4 February 2000 with the name DMWSL 291 plc and is a public company limited by shares, with registered number 03919249. DMWSL 291 plc changed its name to Tullow Oil plc on 28 April 2000. The Company is domiciled in the United Kingdom.

The Company's registered office and principal place of business is at 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT, and its telephone number is +44 (0)20 3249 9000.

The principal laws and legislation under which the Company operates are the Companies Act 2006 and the regulations made thereunder.

3. DIRECTORS

The Directors of the Company (in such capacities, each having their business address at 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT, United Kingdom), are as follows:

Name	Role
Dorothy Thompson CBE	Executive Chair
Les Wood	Chief Finance Officer
Jeremy Wilson	Senior Independent Non-Executive Director
Mike Daly	Independent Non-Executive Director
Sheila Khama	Independent Non-Executive Director
Genevieve Sangudi	Independent Non-Executive Director
Martin Greenslade	Independent Non-Executive Director

4. DIRECTORS' INTERESTS IN THE COMPANY

The interests in Tullow Shares of the Directors (and their connected persons within the meaning of Section 252 of the Companies Act 2006) as at the Latest Practicable Date were as follows:

Directors' interests in Tullow Shares

	Number of Tullow Shares	Percentage of existing issued share capital, including any interests under share schemes (see below) as at the Latest Practicable Date
Executive Directors		
Dorothy Thompson CBE	68,148	0.00483%
Les Wood	208,884	0.01481%
Non-Executive Directors		
Jeremy Wilson	87,959	0.00623%
Mike Daly	4,795	0.00034%
Genevieve Sangudi	—	—
Sheila Khama	—	—
Martin Greenslade	—	—
Total	**369,786**	**0.02621%**

Directors' interests in Tullow Shares pursuant to employee share schemes

As at the Latest Practicable Date, Les Wood held the following outstanding options and awards over Tullow Shares under the Tullow Incentive Plan:

Share plan	Grant date	Number of options
DIR 5 Yr	08/02/2018	148,802
DIR 5 Yr	14/02/2019	288,617
DIR 5 Yr—Div Equivalent	10/05/2019	2,605
DIR 5 Yr—Div Equivalent	10/05/2019	5,052
DIR 5 Yr—Div Equivalent	17/10/2019	1,372
DIR 5 Yr—Div Equivalent	17/10/2019	2,661
Total:		**449,109**

No other Directors hold outstanding options and awards over Tullow Shares under the Tullow Incentive Plan.

As at the Latest Practicable Date, no options or awards over Tullow Shares had been issued to the Directors under the Tullow Incentive Plan in respect of the Transaction. The Transaction will not result in the acceleration of any options or awards over Tullow Shares held by the Directors, or held by any other participant in the Tullow Incentive Plan.

5. DIRECTORS' SERVICE AGREEMENTS AND ARRANGEMENTS

Save as set out in this Section 5, there are no existing or proposed service agreements or letters of appointment between the Directors and any member of the Tullow Group.

Executive Directors: Service contracts

Details of the appointment of the Executive Directors (and Rahul Dhir as the future CEO) are shown in the table below.

	Date of appointment	Date of contract	Notice period from Company (months)	Notice period from Director (months)	Base salary
Executive Directors					
Dorothy Thompson CBE	25.04.18 (as a Non-Executive Director) 20.07.18 (as Non-Executive Chair)	Appointed Executive Chair 9.12.19	6	6	£600,000
Les Wood	5.01.17 (as Interim Chief Financial Officer)	20.06.17	12	6	£461,500
Proposed Executive Director					
Rahul Dhir	01.07.20	20.04.20	12 during first 12 months; 6 thereafter	6	£580,000

Dorothy Thompson, for the period she performs her interim role as Executive Chair and during any transition period following the commencement of Rahul Dhir as the new CEO on 1 July 2020 receives an annual fee of £600,000, pro-rated as appropriate. She does not receive any further benefit or pension provision or receive incentive awards. Ms Thompson will revert to her previous role of non-executive Chair following Mr Dhir's appointment and a transition of duties effected. Her annual fee is thereafter intended to revert to £300,000.

Les Wood is engaged under a rolling service agreement with Tullow Group Services Limited which may be terminated by Mr Wood on six months' notice and by Tullow Group Services Limited on 12 months' notice. In the event of Tullow Group Services Limited terminating Mr Wood's service agreement, the Company's policy is to make a payment in lieu of notice where necessary, limited to base salary and contractual benefits.

In the event Mr Wood is guilty of serious or persistent misconduct or in certain other specified circumstances, Tullow Group Services Limited may terminate his employment with immediate effect and without notice or payment in lieu.

In addition to his annual salary, Mr Wood is entitled to the following main benefits: (i) a pension contribution or salary supplement of 25 per cent. of salary for the year ended 31 December 2019; (ii) benefit provision, including health insurance and life assurance in line with the Group's policy; and (iii) a TIP award with a maximum potential of 400 per cent. of salary, based on the achievement of applicable performance conditions, with an award of up to 200 per cent. being divided evenly between cash and deferred shares and any remainder being awarded entirely in deferred shares.

Executive Directors are reimbursed for all reasonable and properly documented expenses incurred in performing their duties.

Non-Executive Directors: Letters of appointment

Details of the appointment of the Non-Executive Directors are shown in the table below.

	Date of appointment	Date current engagement commenced	Expiry of current term	Notice period from Company (months)	Fees paid in 2019
Non-Executive Directors					
Jeremy Wilson	21.10.13	21.10.19	20.10.22	3	£90,274
Mike Daly	01.06.14	30.05.20	31.05.23	3	£80,000
Sheila Khama	26.04.19	26.04.19	25.04.22	6	£44,520
Genevieve Sangudi	26.04.19	26.04.19	25.04.22	6	£44,520
Martin Greenslade	01.11.19	01.11.19	31.10.22	6	£10,863

The Non-Executive Directors are appointed by letters of appointment, which may be terminated by either party giving to the other not less than three- or six-months' notice in writing (as set out above).

In the event a Non-Executive Director is guilty of serious or persistent misconduct or in certain other specified circumstances, the Company may terminate their appointment with immediate effect and without notice or any obligation to pay compensation or damages.

The fees paid to each of the Non-Executive Directors consist of a basic fee of £65,000 per year and, as relevant, additional fees for acting as chair of a Board committee (£15,000 per year in respect of the Remuneration Committee and the Safety and Sustainability Committee and £20,000 per year in respect of the Audit Committee) and an additional fee of £15,000 per year for the Director nominated as Senior Independent Director (being Jeremy Wilson as at the Latest Practicable Date).

Each Non-Executive Director is entitled to reimbursement of reasonable expenses incurred in the course of his duties.

No Non-Executive Director is entitled to any benefit upon the termination of their appointment.

Save as disclosed above, (i) there are no service contracts between any Director and the Company or any member of the Group; and (ii) no such contract has been entered into or amended within the six months preceding the date of this document. There are also no service contracts between the Company or any member of the Group and any person who has resigned as a Director in the period between the Transaction Announcement and the publication of this document. No such contract has been entered into or amended within the six months preceding the date of this document.

6. PROPOSED DIRECTOR

On 21 April 2020, the Company announced the appointment of Rahul Dhir as the new Chief Executive Officer. This appointment will be effective from 1 July 2020. Mr Dhir currently holds 1,346,000 Tullow Shares, which represent 0.09540 per cent. of the total issued share capital of Tullow as at the Latest Practicable Date.

Biography

Mr Dhir is currently CEO of Delonex Energy, an Africa-focused oil and gas company that he founded in 2013. Under his leadership, Delonex has delivered low-cost drilling and seismic operations along with leading social and environmental performance in Sub-Saharan Africa. In Chad, the company has achieved material exploration success and discovered substantial oil resources. Delonex has also delivered exploration campaigns in Ethiopia and Kenya where Delonex operates Block 12A (in which Tullow was a non-operating partner until January 2020).

Prior to establishing Delonex, Mr Dhir served as Managing Director and CEO of Cairn India from its IPO in 2006 until 2012. During his tenure, Cairn India delivered operated production of over 200,000 barrels of oil per day with operating costs of less than US$5/bbl. Cairn India also successfully delivered over US$5 billion of development projects including the world's longest heated pipeline at a finding and development cost of less than US$5/bbl.

Mr Dhir started his career as a Petroleum Engineer, before moving into investment banking where he led teams at Morgan Stanley and Merrill Lynch, advising major oil & gas companies on merger and acquisition and capital market related issues. Mr Dhir is a UK citizen and was educated at the Indian Institute of Technology (BTech), the University of Texas (MSc) and the Wharton School (MBA).

Service agreement

Mr Dhir will be employed under a rolling service agreement with Tullow Group Services Limited, which may be terminated by Mr Dhir on six months' notice and by Tullow Group Services Limited on 12 months' notice (during the first 12 months of his employment) and six months' notice thereafter. In the event of Tullow Group Services Limited terminating Mr Dhir's service agreement, in line with the Company's past practice, the Company would make a payment in lieu of notice where necessary, limited to base salary and contractual benefits. Mr Dhir's annual basic salary will be £580,000.

In the event Mr Dhir is guilty of serious or persistent misconduct or in certain other specified circumstances, Tullow Group Services Limited may terminate his employment with immediate effect and without notice or payment in lieu.

In addition to his annual salary, Mr Dhir is entitled to the following main benefits: (i) a pension contribution or salary supplement of 15 per cent. of salary; (ii) benefit provision, including health insurance and life assurance in line with the Group's policy; and (iii) a TIP award.

For 2020, Mr Dhir will be eligible to receive a TIP award of up to 200 per cent. of base salary, assuming a 1 July 2020 start date, with an award of up to 100 per cent. being divided evenly between cash and deferred shares and any remainder being awarded entirely in shares deferred for five years. From 2021 onwards, he will be eligible to receive a TIP award on the same basis as Mr Wood.

Mr Dhir will also be granted in due course additional share incentive awards to compensate him for awards that he will forfeit on leaving his current employer.

7. Significant Shareholders

As at the close of business on the Latest Practicable Date, so far as the Directors are aware, no person other than those listed below was interested, directly or indirectly, in three per cent. or more of the issued share capital of Tullow:

Name	Number of Tullow Shares	Percentage of existing issued share capital as at the Latest Practicable Date
Sam Dossou-Aworet	184,081,941	13.05%
M&G plc	73,686,244	5.22%
RWC Asset Management LLP	71,022,015	5.04%
Summerhill Trust Company (Isle of Man) Limited	58,838,104	4.17%
Azvalor Asset Management S.G.I.I.C., S.A.	45,533,489	3.23%
Goldman Sachs & Co. LLC[1]	46,516,145	3.30%
Total significant shareholdings	479,677,938	34.01%

(1) Goldman Sachs & Co. LLC is the holder of a derivative position in 37,185,851 Tullow Shares via securities lending.

8. Material contracts

8.1 The Retained Group

The following is a summary of each material contract (other than contracts entered into in the ordinary course of business) to which Tullow or any member of the Tullow Group is a party, for the two years immediately preceding the publication of this document, and each other contract (not being a contract entered into in the ordinary course of business) entered into by Tullow or any member of the Tullow Group which contains any provisions under which Tullow or any member of the Tullow Group has an obligation or entitlement which is material to Tullow as at the date of this document, in relation to the Retained Group:

(a) **Sale and Purchase Agreement and other Transaction Agreements**

Details of the Sale and Purchase Agreement and the other Transaction Agreements are set out in Part V (*Summary of the Principal Terms of the Transaction*) of this document.

(b) **Sponsors' Agreement**

On or around the date of this document, the Company and the Joint Sponsors entered into a sponsors' agreement pursuant to which the Joint Sponsors have agreed, subject to certain conditions, to act as the Company's sponsors in relation to the Transaction (the "Sponsors' Agreement"). The Company is providing the Joint Sponsors with: (i) certain undertakings which will require it to either consult with or obtain the prior consent of the Joint Sponsors before taking certain actions; and (ii) certain warranties in relation to the Group and the Interests. In addition, the Company is providing the Joint Sponsors with certain indemnities which are customary for an agreement of this nature. The liability of the Company under the Sponsors' Agreement is unlimited by both time and amount. Pursuant to the terms of the Sponsors' Agreement, the Joint Sponsors may terminate the Sponsors' Agreement on the occurrence of certain customary events including a breach of the Sponsors' Agreement or a material misstatement in or omission from this document.

The Company has agreed to bear all of the Joint Sponsors' costs and expenses of, or in connection with, the Transaction, the General Meeting, this document and the Sponsors' Agreement.

(c) **RBL Facility**

On 29 November 2017, the Company completed a refinancing of its reserves-based lending credit facilities, which currently comprises a senior secured revolving credit facility described below (the "RBL Facility"). Since the March 2020 RBL Facility redetermination, commitments were voluntarily reduced by the Company from US$2.4 billion to US$1.98 billion. As of the March 2020 RBL Facility redetermination, the borrowing base for this facility includes assets in Ghana (the Group's interests in the Jubilee field and the TEN fields), Gabon (including the Group's interests in the Tchatamba fields, Simba field, Niungo field, Echira field, Ezanga field and the Group's interest in the fields which form the subject of the Ruche Exclusive Exploitation Authorisation, namely Tortue, Ruche and Ruche North East fields), Equatorial Guinea (the Group's interests in the Ceiba field and Okume Complex fields) and Côte d'Ivoire (the Group's interests in the Espoir field).

Loan facilities similar to the RBL Facility are known as net present value facilities, with the borrowing base amounts thereunder based on the expected present value of future cash flows from producing assets, taking into account, amongst other things, the Group's reserves, production and capital and operating expenditure. The borrowing base amount under the RBL Facility is re-determined every six months at the end of March and September.

The RBL Facility Agreement

On 22 August 2005, the Company and certain of its subsidiaries entered into the RBL Facility, as amended and/or amended and restated from time to time, most recently pursuant to an amendment and restatement agreement dated 21 November 2017 (the "ARA"), with, among others, ING Belgium SA/NV, DNB (UK) Limited, Lloyds Bank plc, Natixis, Natixis (London Branch), Credit Agricole Corporate and Investment Bank, The Standard Bank of South Africa Limited, The Standard Bank of South Africa Limited (Isle of Man Branch), BNP Paribas, JP Morgan Chase Bank N.A (London Branch), Barclays Bank PLC, Deutsche Bank AG (Amsterdam Branch), Standard Chartered Bank, Société Générale and Sumitomo Mitsui Banking Corporation Europe Limited as mandated lead arrangers, ABSA Bank Limited, Barclays Bank of Ghana Limited, ABN AMRO Bank NV and Bank of China Limited (London Branch) as lead arrangers, Nedbank Limited and The Bank of Tokyo-Mitsubishi UFG, Ltd as arrangers, Lloyds Bank plc as global modelling bank, global technical bank and co-ordinating technical bank, Natixis as agent and global senior agent, BNP Paribas as security trustee, BNP Paribas, Credit Agricole Corporate and Investment Bank, ING Belgium SA/NV, DNB Bank ASA and the Standard Bank of South Africa as global technical banks, ING Belgium SA/NV and DNB (UK) Limited as documentation banks, DNB Bank ASA (London Branch), ING Belgium SA/NV, Natixis and Credit Agricole Corporate and Investment Bank as fronting banks (the "RBL Facility Agreement").

The Tullow Uganda entities are not obligors or borrowers under the RBL Facility and the Interests are not borrowing base assets.

The RBL Facility Agreement currently provides for a senior multicurrency revolving facility of US$1.98 billion for the purposes of: (i) meeting liabilities under the RBL Facility Agreement in relation to any letter of credit in respect of which demands have been made; (ii) funding the Group's capital expenditure programme approved by the global technical banks and for general corporate purposes (including acquisitions); and (iii) in the case of any letter of credit issued under the RBL Facility Agreement, towards providing security, credit enhancement or financial assurance for the performance of (among other things): (a) any of the Group's exploration, development or production obligations; or (b) any of the Group's obligations under any production sharing, joint operating or similar agreement.

The RBL Facility Agreement is secured by English law share charges, English law debentures, Gabonese law share pledges, Isle of Man law share charges, Jersey law security interest agreements, certain Dutch law security agreements and certain French law bank account pledge agreements.

Repayment and maturity

The final maturity date of the RBL Facility Agreement is the earlier of: (i) 21 November 2024; and (ii) 31 March or 30 September (whichever is later) immediately preceding the first date on which the aggregate commercial reserves for all the relevant borrowing base assets to which the RBL Facility is referable are projected to be 20 per cent. (or less) of the aggregate of initial reserves for all such borrowing base assets.

Following a voluntary cancellation request issued by the Company on 24 March 2020, US$210 million of commitments were cancelled as at 31 March 2020, which reduced available commitments to US$2.19 billion. A further voluntary cancellation request was issued by the Company on 29 May 2020, such that a further US$210 million of commitments were cancelled as at 8 June 2020, reducing available commitments to US$1.98 billion. Commitments under the RBL Facility amortise according to a pre-agreed schedule of amortisation, scheduled for each 1 April and 1 October occurring before the final maturity date. Due to the voluntary cancellation of commitments taking commitments below the amortisation amount scheduled for 1 October 2020, the next amortisation of approximately US$2 million is scheduled for 1 April 2021. The Company can also voluntarily cancel the whole or any part (being a minimum amount of US$10 million and an integral multiple of US$10 million) of the commitments upon delivering at least five business days' notice to the facility agent.

Interest and fees

The rate of interest payable on loans under the RBL Facility is the rate per annum equal to the aggregate of the applicable margin plus LIBOR (in the case of loans in US dollars or pounds sterling) or EURIBOR (in the case of loans in euros). The applicable margin varies based on the ratio of consolidated total net borrowings to consolidated EBITDA on the date on which the loan is outstanding. Default interest is also payable, at a rate of 2 per cent. per annum higher than the standard rate of interest payable on loans under the RBL Facility, on overdue amounts. The borrowers are required to pay a commitment fee, quarterly in arrears, based on:

(a) the daily amount (if any) by which the aggregate commitments under the RBL Facility (the "Global Commitments") exceed the amount which is the lower of: (i) the sum of the applicable borrowing base amount applicable on that day and US$350 million; and (ii) the Global Commitments applicable on that day (such lower amount being the "Maximum Available Amount"), at a percentage rate per annum calculated by multiplying the then applicable margin by a set rate; and

(b) the daily amount (if any) by which the applicable Maximum Available Amount exceeds the sum of the outstanding loans under the RBL Facility, at a percentage rate per annum calculated by multiplying the then applicable margin by a set rate.

Each borrower that has requested a letter of credit under the RBL Facility is also required to pay a commission quarterly in arrears based on:

(a) the daily amount (if any) by which the exposure under each letter of credit (being the daily difference between the face value of each letter of credit and the aggregate amount of all claims thereunder that have been paid, the "LC Exposure") exceeds the amount of approved cash cover provided for that letter of credit, at a percentage rate per annum calculated by multiplying the then applicable margin by a set number; and

(b) the daily amount of the LC Exposure under each letter of credit in respect of which approved cash cover has been provided, at a set rate per annum.

Representations, warranties, covenants and events of default

The RBL Facility Agreement contains customary representations, information undertakings, general undertakings and events of default, in each case subject to certain exceptions and materiality qualifications. Among other things, the general undertakings contain restrictions on Tullow and certain members of the Group in relation to disposals, acquisitions, change of business, incurrence of financial indebtedness and the provision of security. As well as the customary events of default, the occurrence of the following shall constitute an event of default: (i) any subsidiary that holds an interest in borrowing base assets or obligor ceasing to be wholly owned by the Group; (ii) the nationalisation or expropriation (or an announcement of intent in respect thereof) of all or part of any borrowing base asset or any oil and gas or revenues derived therefrom in a manner which would result in a material adverse change; (iii) an abandonment of any borrowing base asset that contributes in excess of US$100 million to the then applicable net present value (as described therein); and (iv) the making of any judgement or award in litigation, arbitration or administrative proceedings against an obligor or other key subsidiary which, after deducting amounts receivable under insurances, is equal to or exceeds US$300 million (or the equivalent in one or more other currencies).

The RBL Facility requires Tullow to comply with certain ratios of Covenanted Net Debt to Consolidated EBITDA. These financial terms are calculated in accordance with the RBL Facility Agreement and should be distinguished from the concepts of Net Debt and Adjusted EBITDAX as set out in the Group's latest annual report and accounts (being those for the year ended 31 December 2019) and used elsewhere in this document. The applicable ratio is tested bi-annually with respect to the most recent financial statements delivered pursuant to the RBL Facility Agreement. In the event of non-compliance with the applicable ratio, the RBL Facility Agreement (subject to certain limitations) allows Tullow to procure a cure of such non-compliance by a cash subscription for Tullow Shares and/or receipt of an injection of cash by way of certain subordinated debt such that the relevant ratio is satisfied by reducing Covenanted Net Debt accordingly. No more than one such equity cure can be made within a 12-month period and no more than two equity cures may be made during the period from 21 November 2017 to the final maturity date of the RBL Facility.

Prepayment

The RBL Facility is to be prepaid in full immediately upon the occurrence of certain events, including a change of control of Tullow.

(d) **IFC Senior Secured Revolving Credit Facility Agreement (cancelled 31 October 2019)**

On 29 May 2009, the Company and certain of its subsidiaries entered into a finance contract in respect of a senior secured revolving credit facility, as amended and/or amended and restated from time to time, including pursuant to an amendment and restatement agreement dated 21 November 2017, with the International Finance Corporation as original lender and agent (the "IFC Senior Secured Revolving Credit Facility Agreement"). Commitments under the IFC Senior Secured Revolving Credit Facility were US$100 million.

In accordance with its terms, the IFC Senior Secured Revolving Credit Facility was fully repaid and terminated on 31 October 2019.

(e) **Corporate Facility (cancelled 22 November 2018)**

On 14 December 2009, the Company and certain of its subsidiaries entered into a secured revolving credit facility, as amended and/or amended and restated from time to time, with, among others, Bank of America Merrill Lynch International Limited, BNP Paribas, Credit Agricole Corporate and Investment Bank, HSBC Bank plc, ING Bank N.V., Natixis, Société Générale, Standard Chartered Bank, The Royal Bank of Scotland plc and The Standard Bank of South Africa Limited, as mandated lead arrangers, BNP Paribas as agent and security trustee and Credit Agricole Corporate and Investment Bank as technical bank (the "Corporate Facility Agreement").

The Corporate Facility Agreement provided for a multicurrency revolving facility (the "Corporate Facility") for the purposes of funding oil and gas related expenditure of the Company and its subsidiaries from time to time and for general corporate purposes (including acquisitions). The Corporate Facility provided for commitments of up to US$1 billion which reduced to US$800 million from April 2017, US$600 million from January 2018, US$500 million from April 2018, US$400 million from October 2018 and US$nil from 4 April 2019. The Corporate Facility was cancelled in full on 22 November 2018.

(f) **RBL Lender Intercreditor Agreement**

On 22 August 2005, the Company and certain of its subsidiaries entered into an intercreditor agreement in connection with the RBL Facility with, among others, the borrowers and guarantors of the RBL Facility, the lenders under the RBL Facility and BNP Paribas as security trustee (the "RBL Lender Intercreditor Agreement"). The RBL Lender Intercreditor Agreement has been amended and restated pursuant to the ARA.

The RBL Lender Intercreditor Agreement provides that liabilities owed by the obligors to: (i) the lenders under the RBL Facility; (ii) certain banks that act as counterparties to certain secured hedging agreements; and (iii) certain providers of secured letters of credit not provided under the RBL Facility shall rank *pari passu* and without preference as between these liabilities.

(g) **2022 Senior Notes**

On 8 April 2014, the Company issued US$650 million in aggregate principal amount of 6.25 per cent. Senior Notes (the "2022 Senior Notes"). The 2022 Senior Notes mature on 15 April 2022. The 2022 Senior Notes are guaranteed on a senior subordinated basis by certain subsidiaries of the Company, which include the Tullow Uganda entities which have provided subordinated guarantees. The indenture provides that these guarantees shall be automatically and unconditionally released and discharged upon the completion of the Transaction.

The Company may redeem all or part of the 2022 Senior Notes at any time on or after 15 April 2017 at a price equal to par plus 75 per cent. of the applicable coupon, declining to par plus 50 per cent. of the applicable coupon on 15 April 2018, declining to par plus 25 per cent. of the applicable coupon on 15 April 2019 and at par from and after 15 April 2020. At any time prior to 15 April 2017, the Company may redeem all or part of the 2022 Senior Notes at a redemption price equal to 100 per cent. of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of redemption plus a "make whole" premium. At any time prior to 15 April 2017, the Company may on one or more occasions redeem up to 35 per cent. of the aggregate principal amount of the 2022 Senior Notes, using the net proceeds from certain equity offerings at a redemption price equal to 106.25 per cent. of the principal amount of the 2022 Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption; provided that at least 65 per cent. of the aggregate principal amount of the 2022 Senior Notes remain outstanding after the redemption. Upon the occurrence of certain specified change of control events, the holders of the 2022 Senior Notes will have the right to require the Company to offer to repurchase the 2022 Senior Notes at a purchase price equal to 101 per cent. of their principal amount, plus accrued and unpaid interest, if any, to the date of purchase.

The 2022 Senior Notes Indenture limits, among other things, the ability of the Company and its restricted subsidiaries to make certain payments, including dividends and other distributions, with respect to outstanding share capital, sell, lease or transfer certain assets, including shares of any of the Company's restricted subsidiaries, to make certain investments or loans and to incur additional financial indebtedness. These limitations are, however, subject to a number of important qualifications and exceptions. The 2022 Senior Notes Indenture also contains customary events of default.

(h) **Convertible Bonds**

The Group is party to seven convertible bond contracts in respect of its US$300 million 6.625 per cent. guaranteed convertible bonds due 12 July 2021 (the "Convertible Bonds"), namely the Convertible Bond Trust Deed, the Convertible Bond Terms and Conditions, the Convertible Bond Agency Agreement, the Convertible Bond Calculation Agency Agreement, the Convertible Bond Subscription Agreement, the Convertible Bond Subordination Agreement and the Convertible Bond Deed Poll, each of which is summarised below.

The Convertible Bond Trust Deed

On 12 July 2016, Tullow Oil (Jersey) Limited (the "Bond Issuer"), Tullow Oil plc (the "Parent Bond Guarantor"), various Subsidiary Bond Guarantors listed therein (the "Subsidiary Bond Guarantors" and together with the Parent Bond Guarantor, the "Bond Guarantors") and Deutsche Trustee Company Limited as trustee entered into a trust deed constituting the Convertible Bonds (the "Convertible Bond Trust Deed"), listed on the Official List of the Channel Islands Securities Exchange Authority Limited and admitted to trading on the market of the Channel Islands Securities Exchange.

The Convertible Bond Trust Deed provides that Deutsche Trustee Company Limited will act as trustee of the Convertible Bond Trust Deed and that the Bond Guarantors will provide certain guarantees. The Parent Bond Guarantor guarantees all payments due from, and the delivery of Preference Shares by, the Bond Issuer under the Convertible Bond Trust Deed and the terms and conditions of the Convertible Bonds (the "Convertible

Bond Terms and Conditions”). Each Subsidiary Bond Guarantor jointly and severally guarantees on a senior subordinated basis all payments due from the Bond Issuer under the Convertible Bond Trust Deed and the Convertible Bond Terms and Conditions and all payments due from the Parent Bond Guarantor in respect of the same (the “Subordinated Guarantee”). The Subsidiary Bond Guarantors do not guarantee the Parent Bond Guarantors’ guarantee of the Bond Issuer’s obligations in respect of delivering Preference Shares. Any claims of bondholders under the Subordinated Guarantee will rank subordinate in right and priority of payment to such Subsidiary Bond Guarantor’s obligations under certain senior financing agreements in accordance with the terms of the Convertible Bond Subordination Agreement (as defined below).

The Bond Guarantors’ obligations are continuing and remain in full force and effect until no sum remains payable under the Convertible Bond Trust Deed or the Convertible Bond Terms and Conditions. The Bond Guarantors also each provide an indemnity for the benefit of bondholders.

The Convertible Bond Trust Deed contains covenants from the Bond Issuer, the Parent Bond Guarantor and the Subsidiary Bond Guarantors (including the Bond Issuer’s covenant to pay) for the benefit of the trustee and bondholders and governs the trustee’s role and conditions of engagement. The trustee is granted the ability to waive default, consent to amendments and consent to substitution of the Bond Issuer in certain limited circumstances. The trustee can retire on giving notice or be removed by an extraordinary resolution of bondholders, but such retirement or removal will not be effective unless a successor trustee has been appointed, subject to certain conditions.

The Convertible Bond Trust Deed incorporates the Convertible Bond Terms and Conditions.

The Convertible Bond Terms and Conditions

The Convertible Bond Terms and Conditions provide that each US$200,000 principal amount of a Bond is convertible into preference shares of the Bond Issuer (the “Preference Shares”) and each Preference Share will be allotted at a price equal to the paid-up value of US$200,000 (a “Conversion Right”). This Conversion Right may be exercised at the option of a bondholder from 22 August 2016 to the close of business on the date falling seven days prior to 12 July 2021 or any other relevant maturity date, subject to certain conditions and exceptions. All Preference Shares issued will be automatically and mandatorily transferred to the Parent Bond Guarantor who will issue or transfer and deliver Tullow Shares to the bondholder in consideration for the receipt of Preference Shares. The calculation agent will determine the number of Tullow Shares allotted by reference to an exchange price which may be adjusted in accordance with the Convertible Bond Terms and Conditions. The initial exchange price was US$3.52 per Tullow Share.

The Bond Issuer and the Parent Bond Guarantor give various undertakings in favour of the bondholders. With regard to redemption, the Bond Issuer has the option to redeem all outstanding bonds at their principal amount plus accrued and unpaid interest at any time after 29 July 2019 (if a volume weighted average price threshold is met) or if 85 per cent. or more of the Convertible Bonds have been converted. Bondholders can redeem on a change of control of the Parent Bond Guarantor or release and no replacement of all of the Subsidiary Bond Guarantors. The events of default in the Convertible Bond Terms and Conditions include non-payment, breach of obligations, cross-default, non-compliance with a judgment, unenforceable guarantees, various insolvency events and the Bond Issuer ceasing to be a wholly owned subsidiary.

The Convertible Bond Agency Agreement

On 12 July 2016, the Bond Issuer, the Parent Bond Guarantor, the Subsidiary Bond Guarantors, Deutsche Bank AG, London Branch as principal paying and conversion agent, Deutsche Bank Luxembourg S.A. as registrar and transfer agent (together with the principal paying and conversion agent, the “Agents”), and the trustee entered into a paying, transfer and conversion agency agreement (the “Convertible Bond Agency Agreement”) pursuant to which the Bond Issuer and each Bond Guarantor appoint the Agents as their agents in respect of the Convertible Bonds and each Agent accepts their appointment to severally perform their roles.

The Convertible Bond Agency Agreement provides for, amongst other things, payment of principal and interest in respect of the Convertible Bonds and the exercise of bondholder’s Conversion Rights. The Bond Issuer and the Bond Guarantors, subject to obtaining required approvals, the prior written approval of the trustee and giving valid notice, can appoint additional agents and vary or terminate the appointment of an Agent. Agents can also resign at any time giving valid notice and are subject to certain automatic termination triggers such as being the subject of insolvency proceedings. In most cases, the resignation or removal of an Agent will not be effective until a successor agent is appointed.

The Convertible Bond Calculation Agency Agreement

The Bond Issuer, the Parent Bond Guarantor and Conv-Ex Advisors Limited as calculation agent (the "Calculation Agent") entered into a calculation agency agreement dated 12 July 2016 (the "Convertible Bond Calculation Agency Agreement") pursuant to which the Calculation Agent is appointed by the Bond Issuer and the Parent Bond Guarantor to act as calculation agent in relation to the Convertible Bonds and the Calculation Agent accepts such appointment.

Following notification by the Bond Issuer (failing whom the Parent Bond Guarantor), the Calculation Agent agrees, subject to certain conditions, to make promptly such determinations, calculations or adjustments required and notify the Bond Issuer, Parent Bond Guarantor and the Calculation Agent of the results which will be final and binding (in the absence of bad faith and manifest error). Subject to certain conditions, the Calculation Agent can resign or be removed at any time, in each case upon giving or receiving valid notice. Such resignation or removal will only become effective upon the appointment of a successor calculation agent by the Bond Issuer and Parent Bond Guarantor. The Calculation Agent is also subject to limited automatic termination provisions.

The Convertible Bond Subscription Agreement

On 6 July 2016, the Bond Issuer, the Parent Bond Guarantor, the Subsidiary Bond Guarantors, the Global Co-ordinators, the joint bookrunners and the managers (each as named therein) entered into a subscription agreement (the "Convertible Bond Subscription Agreement") pursuant to which the Bond Issuer agreed to issue the Convertible Bonds on 12 July 2016 to the Managers and the Managers severally agreed to procure subscribers for the Convertible Bonds or subscribe and pay for an agreed portion of the aggregate principal amount of the Convertible Bonds, subject to certain conditions and the satisfaction of agreed conditions precedent.

The Managers are the beneficiaries of certain representations, warranties, and undertakings of indemnification from the Bond Issuer, the Parent Bond Guarantor and the Subsidiary Bond Guarantors. The Bond Issuer and the Parent Bond Guarantor also provide separate undertakings. The Global Co-ordinators (on behalf of the Managers) are entitled to terminate on certain conditions including breach of representations or warranties, non-satisfaction of any conditions precedent and macro-economic events.

The Convertible Bond Subordination Agreement

The Guarantee Subordination Agreement between the Parent Bond Guarantor and the trustee, among others, dated 6 November 2013, as amended and restated on 12 July 2016 (the "Convertible Bond Subordination Agreement") provides for the postponement and subordination of the Subordinated Guarantee (and other subordinated guarantees given by certain group companies in respect of other outstanding bonds issued by the Parent Bond Guarantor) to the Subsidiary Bond Guarantors' obligations owed to certain senior creditors under certain senior financing agreements until such senior liabilities are fully and finally discharged (the "Senior Discharge Date").

The Convertible Bond Subordination Agreement does not purport to rank the senior liabilities or Subordinated Guarantees between themselves but does subordinate the Subordinated Guarantee Subsidiary Bond Guarantors' obligations to future and re-financed senior liabilities. The Subsidiary Bond Guarantors are permitted to make payments under the Subordinated Guarantee before the Senior Discharge Date in limited circumstances including if consent is given by the relevant senior creditors or if the payment is in respect of the principal amount of the Convertible Bond liabilities on or after the final maturity date, among other things.

The Convertible Bond Deed Poll

The conversion and exchange rights of convertible bondholders are guaranteed by the Parent Bond Guarantor on a senior basis pursuant to a deed poll dated 12 July 2016 entered into by the Parent Bond Guarantor in favour of the holders of Preference Shares (the "Convertible Bond Deed Poll"). The Convertible Bond Deed Poll provides for an undertaking to be given by the Parent Bond Guarantor to each holder of Preference Shares (a "Preference Shareholder") to make due and punctual payment of the aggregate paid-up value of the Preference Shares, dividends and other amounts expressed to be payable, subject to certain conditions. The Parent Bond Guarantor further undertakes that after the exercise of a Conversion Right, it will issue or transfer and deliver Tullow Shares in accordance with the Convertible Bond Terms and Conditions. The obligations of the Parent Bond Guarantor under the Convertible Bond Deed Poll are not subordinated.

The Convertible Bond Deed Poll is a continuing guarantee and will remain in full force and effect until all amounts payable in respect of the Preference Shares have been paid in full at which point it will cease to have effect. The release of the Parent Bond Guarantor is accordingly limited. The terms of the Convertible Bond Deed Poll provide that the Parent Bond Guarantor shall be liable to Preference Shareholders as if it were the principal debtor and subrogated to all or any rights of the Preference Shareholders against the Bond Issuer. The Convertible Bond Deed Poll can only be amended by deed poll.

(i) **2025 Senior Notes**

On 23 March 2018, the Company issued US$800 million in aggregate principal amount of seven per cent. Senior Notes (the "2025 Senior Notes"). The 2025 Senior Notes mature on 1 March 2025. The 2025 Senior Notes are guaranteed on a senior subordinated basis by certain subsidiaries of the Company.

The Company may redeem all or part of the 2025 Senior Notes at any time on or after 1 March 2021 at a price equal to par plus 50 per cent. of the applicable coupon, declining to par plus 25 per cent. of the applicable coupon on 1 March 2022, declining to par from and after 1 March 2023. At any time prior to 1 March 2021, the Company may redeem all or part of the 2025 Senior Notes at a redemption price equal to 100 per cent. of the principal amount thereof, plus accrued and unpaid interest, if any, to the date of redemption plus a "make whole" premium. At any time prior to 1 March 2021, the Company may on one or more occasions redeem up to 35 per cent. of the aggregate principal amount of the 2025 Senior Notes, using the net proceeds from certain equity offerings at a redemption price equal to 107 per cent. of the principal amount of the 2025 Senior Notes, plus accrued and unpaid interest, if any, to the date of redemption; provided that at least 65 per cent. of the aggregate principal amount of the 2025 Senior Notes remain outstanding after the redemption. Upon the occurrence of certain specified change of control events, the holders of the 2025 Senior Notes will have the right to require the Company to offer to repurchase the 2025 Senior Notes at a purchase price equal to 101 per cent. of their principal amount, plus accrued and unpaid interest, if any, to the date of purchase.

The 2025 Senior Notes Indenture limits, among other things, the ability of the Company and its restricted subsidiaries to make certain payments, including dividends and other distributions, with respect to outstanding share capital, sell, lease or transfer certain assets, including shares of any of the Company's restricted subsidiaries, to make certain investments or loans and to incur additional financial indebtedness. These limitations are, however, subject to a number of important qualifications and exceptions. The 2025 Senior Notes Indenture also contains customary events of default.

(j) **Guarantee Subordination Agreement**

In connection with the issuance of the 2022 Senior Notes, the trustee for the 2022 Senior Notes acceded to the Company's existing subordination agreement (the "Guarantee Subordination Agreement") on 8 April 2014. In connection with the issuance of the Convertible Bonds, on 12 July 2016, the Guarantee Subordination Agreement was amended and restated and the trustee for the Convertible Bonds acceded to the Guarantee Subordination Agreement. In connection with the issuance of the 2025 Senior Notes, the trustee for the 2025 Senior Notes acceded to the Guarantee Subordination Agreement on 23 March 2018. The Guarantee Subordination Agreement governs the relationships and relative priorities among: (i) the creditors of the RBL Facility (the "RBL Creditors"); (ii) certain banks that act as counterparties to hedging agreements (the "Hedging Banks"); (iii) certain providers of secured letters of credit under the RBL Facility (together with the RBL Creditors and the Hedging Banks, the "Senior Creditors"); and (iv) the trustee for the 2022 Senior Notes, the Convertible Bonds and the 2025 Senior Notes on its own behalf and on behalf of the noteholders (the "Notes Creditors").

The Guarantee Subordination Agreement provides that the liabilities owed by the debtors to the Senior Creditors under the Senior Finance Documents (the "Senior Liabilities") and the liabilities owed by the Bond Guarantors to the Notes Creditors under the Notes Documents (the "Notes Guarantee Liabilities") will rank in right and priority of payment: (i) first, the Senior Liabilities *pari passu* and without any preference between them; and (ii) second, the Notes Guarantee Liabilities *pari passu* and without any preference between them. The parties to the Guarantee Subordination Agreement agree that the liabilities owed by the Company (or certain of the Company's direct and indirect subsidiaries which may in the future issue notes and on-lend the proceeds of such issuance to the Company) to the Notes Creditors under the Notes Documents, certain amounts owed to the trustee under the Notes Documents and certain Notes security enforcement and preservation costs (if any) are senior obligations (and are therefore not Notes Guarantee Liabilities) and the Guarantee Subordination Agreement does not purport to rank, postpone and/or subordinate any of them in relation to the other liabilities. The Guarantee Subordination Agreement does not purport to rank any of the Senior Liabilities as between themselves or any of the Notes Guarantee Liabilities as between themselves. In addition, the

Guarantee Subordination Agreement does not purport to rank any of the liabilities of the Company (or certain of the Company's direct and indirect subsidiaries which may in the future issue notes and on-lend the proceeds of such issuance to the Company).

(k) **Hedging arrangements**

The Company maintains certain commodity hedges to manage its exposure to movements in oil prices. Such commodity derivatives tend to be priced using benchmarks, such as Platts Dated Brent crude oil, which correlate as closely as possible to the Group's underlying oil revenues.

The Group hedges a portion of its estimated oil revenues on a portfolio basis (rather than on a single asset basis), aggregating its oil revenues from substantially all of its African oil interests. The Company primarily transacts its hedging activities with the lenders under the RBL Facility which it considers to have strong credit ratings. The Company has a policy of hedging its expected sales volumes on a graduated two-year rolling basis with the aim to ensure that 60 per cent. of its expected production for the current calendar year and 30 per cent. of its expected production for the following calendar year is hedged. However, as a result of the prevailing low forward prices for Brent oil, the Company ceased to enter into new hedging contracts on 25 February 2020. The Company intends to recommence its hedging programme when forward prices for Brent oil have recovered sufficiently to support the objectives of the Company's hedging strategy. As of 31 May 2020, Tullow had approximately 60 per cent. of its 2020 sales revenue hedged with a floor of approximately US$57/bbl and approximately 40 per cent. of 2021 sales revenue hedged with a floor of approximately US$53/bbl. The mark-to-market of Tullow's hedge portfolio was US$250 million as of 31 May 2020. The Company's hedge position was spread across 15 counterparties. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

In connection with these activities, the Company has entered into International Swaps and Derivatives Association master agreements with several hedging partners. All of the Group's commodity derivatives have been designated as cash flow hedges as at and for the years ended 31 December 2017, 2018 and 2019. All of the Group's commodity hedges have been assessed by the Group to be "highly effective" within the range prescribed under IAS 39/IFRS 9 using regression analysis. However, there is the potential for a degree of ineffectiveness in the Group's commodity hedges arising from, among other factors, the discount on the Group's crude oil located in Africa relative to Platts Dated Brent crude oil and the timing of oil liftings relative to the hedges.

A portfolio of interest rate derivatives, designated as cash flow hedges, was held and matured in 2018.

(l) **TEN FPSO**

On 14 August 2013, Tullow Ghana entered into an engineering, procurement, installation, commissioning and bareboat charter agreement (the "TEN FPSO Contract") with T.E.N. Ghana MV25 B.V. (the "FPSO Contractor"), a subsidiary of MODEC Inc., in respect of an FPSO for use at the Group's TEN fields (the "FPSO"). Tullow Ghana, as operator of the TEN fields, entered into the agreement on behalf of itself and its commercial partners.

The FPSO Contractor agreed to design, procure, construct, install and commission the FPSO. Tullow Ghana will charter and lease the FPSO from the FPSO Contractor for an initial term of 10 years commencing on the date on which the FPSO's offshore completion certificate is issued. Upon the expiration of the initial term, Tullow Ghana has the option to extend the charter period for 10 additional and consecutive one-year extension periods, provided it gives six months' written notice to the FPSO Contractor prior to the expiration of the initial term or any extension thereto (as the case may be). Tullow Ghana is responsible for paying the hire cost during the charter period (which costs include a mobilisation fee, compensation for demobilisation and a specified daily rate).

Tullow Ghana may terminate the TEN FPSO Contract on not less than 30 days' written notice to the FPSO Contractor, provided Tullow Ghana pays the FPSO Contractor hire costs up to the date of termination and, if applicable, interest rate hedging unwinding costs. If the termination occurs during the initial 10-year charter period, Tullow Ghana will also be required to pay demobilisation costs and an early termination fee which will be equal to the value of the remaining initial hire period (less 5 per cent. Ghanaian withholding tax) discounted using a discount rate of 6.5 per cent. per annum on a 360 days per year basis grossed up by 25 per cent. in relation to Ghanaian corporate income tax. An early termination payment is also due by Tullow Ghana in the event that there is an unauthorised requisitioning or taking of the FPSO or Tullow Ghana terminates the agreement for continuing force majeure. No early termination fee is incurred in the event that termination occurs as a result of other conditions, including the actual or constructive total loss of the FPSO or breach of the FPSO Contractor's material obligations under the TEN FPSO Contract. The FPSO Contractor is also entitled to terminate the contract during the charter period under certain circumstances, including a breach of Tullow Ghana's obligations to pay undisputed amounts when they fall due under the TEN FPSO Contract.

Tullow Ghana has the option to purchase the FPSO at any time during the charter period, provided that 180 days' written notice is given to the FPSO Contractor. In addition, if the FPSO Contractor wishes to sell the FPSO to a non-affiliated third party during the charter period, Tullow Ghana has a right of first refusal to purchase the FPSO at the same price and on substantially the same terms as those offered by such third party and has 60 days within which to exercise such right. Upon any purchase of the FPSO, the TEN FPSO Contract will terminate automatically. The FPSO Contractor may grant a mortgage over the FPSO.

The present value of the future minimum lease payments payable under the TEN FPSO Contract, in aggregate, is US$1.3 billion, calculated on a gross basis (as Tullow Ghana has contracted on behalf of its commercial partners). The payments due under the TEN FPSO Contract include a mobilisation fee, compensation for demobilisation and a specified daily rate.

In addition, on 14 August 2013, Tullow Ghana entered into an operation and maintenance services contract (the "TEN O&M Contract") with the FPSO Contractor pursuant to which the FPSO Contractor will provide certain operation and maintenance services in connection with the FPSO during the initial 10-year charter period (the "O&M Period"). Upon the expiration of the O&M Period, Tullow Ghana has the option to extend the TEN O&M Contract for 10 additional and consecutive one-year extension periods.

Provided that Tullow Ghana has terminated the charter of the FPSO, Tullow Ghana may terminate the TEN O&M Contract for convenience on giving at least 30 days' notice. In such event, Tullow Ghana must pay the FPSO Contractor for the services provided to the date of termination and any other amounts owing under the TEN O&M Contract, together with any other cancellation costs incurred by the FPSO Contractor as a result of such termination (including in relation to the demobilisation of personnel and equipment). In addition, the parties to the TEN O&M Contract have termination rights typical for a contract of this nature, including as a result of the occurrence of insolvency events or a material breach by the other party of the terms of the TEN O&M Contract. If the TEN FPSO Contract is terminated, the TEN O&M Contract terminates automatically.

8.2 Interests

The following is a summary of each material contract (other than contracts entered into in the ordinary course of business) to which Tullow or any member of the Tullow Group is a party, for the two years immediately preceding the publication of this document, and each other contract (not being a contract entered into in the ordinary course of business) entered into by Tullow or any member of the Tullow Group which contains any provisions under which Tullow or any member of the Tullow Group has an obligation or entitlement which is material to Tullow as at the date of this document, in relation to the Interests:

(a) **Sale and Purchase Agreements and other Transaction agreements**

Details of the Sale and Purchase Agreement and the other Transaction Agreements are set out in Part V (*Summary of the Principal Terms of the Transaction*) of this document.

(b) **Farm-down agreement**

On 9 January 2017, the Company announced that it had agreed a further farm-down of its assets in Uganda to Total Uganda. Under the sale and purchase agreement, the Company agreed to transfer a 21.57 per cent. interest (out of its holding of 33.3334 per cent. interests, pre-back in of UNOC) (the "2017 Uganda Sale Assets") to Total Uganda for a headline consideration of US$900 million. Pursuant to the terms of the Joint Operating Agreements in relation to the Lake Albert Development Project, CNOOC Uganda had a right of pre-emption to acquire 50 per cent. of the 2017 Uganda Sale Assets on the same terms and conditions as those agreed between the Company and Total Uganda. On 16 March 2017, CNOOC Uganda exercised its right of pre-emption and on 11 October 2017, the sale and purchase agreement with Total Uganda was amended and restated and an equivalent sale and purchase agreement was entered in with CNOOC Uganda, to transfer a 10.7843 per cent. interest (pre-UNOC back-in) out of the Company's 33.3334 per cent. interests to each of Total Uganda and CNOOC Uganda on the same terms. In the final quarter of 2017, Total Uganda, CNOOC Uganda and the Company submitted copies of the signed sale and purchase agreements in accordance with the relevant provisions of the production sharing agreements and Uganda's (Exploration, Development and Production) Act 2013 to the Minister of Energy and Mineral Development of the Republic of Uganda for approval. In March 2018, Total Uganda, the Company and CNOOC Uganda agreed to split the operatorship of the Block 2 licence area for which the Company had operatorship such that Total Uganda would become operator of Block 2 North and CNOOC Uganda would become operator of Block 2 South upon completion of the farm-down.

In August 2019, the Company announced that the sale and purchase agreements with Total Uganda and CNOOC Uganda in relation to the 2017 Uganda Sale Assets had lapsed. This was a result of the parties being unable to agree all aspects of the tax treatment of the transaction with the Government of Uganda, which was a condition precedent to completing those sale and purchase agreements.

9. Litigation

9.1 The Retained Group

Save as disclosed in this Section 9.1, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which Tullow is aware) which may have, or have had, during the 12 months prior to the date of this document, a significant effect on Tullow and/or the Retained Group's financial position or profitability.

(a) **Potential High Court dispute and ICC arbitration with Vallourec**

On behalf of itself and the Jubilee field joint venture partners, Tullow Ghana is claiming from Vallourec Oil and Gas France ("Vallourec") losses of approximately US$299 million, arising from the supply by Vallourec of damaged oil country tubular goods in 2009, together with an indemnity in relation to future remedial costs. The contracts under which the tubular goods were supplied were governed by English and French law. Tullow Ghana issued a pre-action protocol letter in respect of each contract. In October 2015, Tullow Ghana and Vallourec entered into standstill agreements which provide that neither party will proceed with a claim unless a party gives the other 28 days' notice to terminate the applicable standstill agreement. The standstill agreements remain in place.

(b) **Ghana Revenue Authority tax assessments**

In February 2018, Tullow Ghana received an assessment from the Ghana Revenue Authority (the "GRA") for additional oil entitlement ("AOE") totalling US$64 million plus penalties. Tullow Ghana considers that the assessment represents a misapplication of the net cash flow formula in the petroleum agreements, and that on a proper application of the formula it should not be subject to any assessment for AOE. Tullow Ghana issued an objection notice to the GRA in August 2018. In October 2018, the GRA wrote to Tullow Ghana withdrawing the penalties but maintaining the assessment for US$64 million. In November 2018, the Ministry of Finance of Ghana requested all parties to cease proceedings until they determined the Government's position, which is still awaited.

In December 2019, Tullow Ghana received final decisions from the GRA arising from its audit of Tullow Ghana for the financial years 2014 to 2016. Under the final decisions, the GRA sought approximately US$406 million and required approximately US$398 million to be paid by 13 January 2020 (the "GRA Assessments").

The GRA originally issued assessments in December 2018. Tullow Ghana issued its objection to the original assessments on 21 December 2018, on the basis that they breach Tullow Ghana's rights under its petroleum agreements, applicable Ghanaian laws and double taxation treaties. The GRA considered the objection and ultimately issued the GRA Assessments. The GRA is seeking to apply branch profits remittance tax from a law which Tullow Ghana considers is not applicable to Tullow Ghana, since it falls outside the tax regime set out in Tullow Ghana's petroleum agreements and double taxation treaties. In addition, under the GRA Assessments, the GRA has also assessed Tullow Ghana for: (i) unpaid withholding tax liabilities; and (ii) corporate income tax, the majority of which relates to interest expense disallowances. Tullow Ghana considers that these assessments by the GRA also breach Tullow Ghana's rights under its petroleum agreements, applicable Ghanaian law and double taxation treaties and, in some cases, have arisen as the result of errors in the GRA's calculations.

On 10 January 2020, Tullow Ghana issued a notice of dispute under the petroleum agreements which Tullow Ghana considers has suspended Tullow Ghana's obligation to pay any tax under the GRA Assessments until the issues are resolved (amicably or by arbitration) (the "Notice of Dispute"). The Notice of Dispute triggers a minimum 30-day period of negotiations, after which either party has a right but not an obligation to commence arbitration. On 30 January 2020, the GRA and Tullow Ghana agreed to extend this period by a further 30 days.

Following discussions throughout February 2020, on 10 March 2020, Tullow Ghana attended a meeting with the GRA and the Ministry of Energy at which the 30-day negotiation period was recommenced by mutual consent.

On 22 and 23 April 2020, the GRA issued two further letters stating the amounts claimed and asserting that interest is accruing on such amounts:

(a) US$27,383,256.04 corporate income tax for the Deepwater Tano contract area for the 2014 to 2016 years of assessment (reduced from US$60,069,618.27, which the GRA had demanded in previous correspondence); and

(b) US$337,608,453.28 withholding tax and branch profits remittance tax liability.

The Company issued a letter on 12 May 2020 in response to the GRA disputing the amounts above and stating that any obligation to pay tax demanded by the GRA is suspended following the Notice of Dispute. The Ministry of Energy has recently indicated a wish to settle these matters in dispute amicably and to see if arbitral proceedings brought against the State can be avoided. On 16 June 2020, the Company issued a further letter to the GRA, particularising its case as to why the disputed amounts are not payable.

Negotiations with the GRA remain ongoing.

(c) **Arbitral proceedings in relation to the Wisting licence**

In January 2013, Tullow Overseas Holdings B.V. ("TOH") acquired Spring Energy Norway AS ("Spring") from HitecVision V ("Hitec"), a Norwegian private equity company, and Spring employee minority shareholders. In addition to the initial consideration payable under the sale and purchase agreement for Spring (the "Spring SPA"), TOH undertook to make contingent bonus payments to Hitec and the Spring employee minority shareholders in the event of the discovery on or before 31 December 2016 of commercially viable reserves from four identified drilling prospects (including the Wisting prospect in licence PL537 ("PL537")).

In September 2013, OMV Norge AS, the operator of PL537, announced that it had made a discovery by drilling the Wisting prospect. Hitec claims that the conditions for a bonus payment under the Spring SPA had been met in respect of the Wisting prospect in PL537 as at 31 December 2016. Tullow disputes this position. An arbitration was commenced in Norway to determine if a bonus payment is payable in respect of the Wisting discovery and a decision is expected to be made in late 2020. Hitec has claimed US$95 million, which includes interest that is estimated to accrue until the end of the 2020 financial year (which TOH has disputed). This claim amount is based on a preliminary calculation that is subject to update.

In 2016, TOH sold its interest in PL537 to Equinor but TOH remains responsible for this dispute.

9.2 Interests

Save as disclosed in this Section 9.2, there are no governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened of which Tullow is aware) which may have, or have had, during the 12 months prior to the date of this document, a significant effect on the financial position or profitability of the Interests.

(a) **VAT claim**

In October 2012, Tullow Uganda filed an appeal in the Uganda High Court against the decision of the URA to deny a refund of input VAT and to nullify assessments raised in respect of imported services. Following a court-mandated mediation process, a partial consent judgment was entered into on 3 November 2014 nullifying the assessments raised in respect of VAT on import services.

On 9 January 2018, the Uganda High Court: (i) ruled that it lacked jurisdiction in respect of Tullow Uganda Limited's claim that it is entitled to a VAT refund of US$50 million; and (ii) declined to rule on a counterclaim by the URA that it is entitled to US$3.6 million in respect of input tax credit previously refunded to Tullow Uganda. Tullow has appealed this ruling. It is expected that the URA will seek a review of the High Court's failure to rule on the counterclaim. No date has yet been given for the appeal to be heard. Once scheduled, a judgment would be expected within nine to 18 months.

In December 2013, Tullow Uganda Operations Pty Limited commenced arbitration proceedings against the Republic of Uganda under the Block 2 production sharing agreement for breach of its contractual rights under the agreement relating to VAT, seeking damages to be quantified in due course. During the process for constituting the arbitral tribunal, the proceedings were stayed by agreement between the parties pending the outcome of the court process in Uganda as described above, and they remain stayed to date.

(b) **Jackson Wabyona claim**

In February 2017, Jackson Wabyona filed an application to set aside the Uganda High Court consent judgment in respect of the settlement entered into in June 2015 between Tullow Uganda, the Government of Uganda and the URA in relation to capital gains tax payable on Tullow Uganda's farm-down of a portion of its Ugandan interests to Total Uganda and CNOOC Uganda in 2012 (the "2015 Settlement"). The application alleges that the consent judgment is illegal, fraudulent and ultra vires and has resulted in a loss of taxes of more than US$460 million.

An application to strike out the claim was dismissed in May 2017. Tullow has appealed this dismissal and filed an application to the Uganda High Court to stay the main application pending the outcome of this appeal. The stay application was granted on 13 June 2017. A memorandum of appeal was filed in October 2017 and the matter now awaits scheduling by the Court. Once scheduled, a judgment would be expected within nine to 18 months.

On 29 April 2020, Tullow Uganda received a further letter from Jackson Wabyona, giving notice of intention to sue. The letter purported to calculate loss of taxes, interest and costs due to the URA as a result of the 2015 Settlement at US$1.123 billion. On 15 May 2020, Mr Wabyona filed an application in the Uganda High Court against Tullow Uganda, the Attorney General of Uganda, the URA and their respective legal advisers seeking to recover the financial and monetary loss occasioned to Uganda as a result of the 2015 Settlement on the grounds that the 2015 Settlement is illegal and void. The application does not set out the amount claimed but instead asks the Court to make an assessment. Summons to file a defence in respect of this claim was served on Tullow Uganda on 25 May 2020. Tullow Uganda filed its defence in relation to the claim on 10 June 2020. Dates for the trial and delivery of judgment have yet to be determined, but the Uganda High Court has indicated that it considers the matter to be urgent and will bear this in mind in giving its directions. Mr Wabyona is also seeking court orders to block the Transaction and create a lien on the proceeds of the Transaction or Tullow Uganda's licence interests as security for this claim, should it be successful. However, Tullow has been advised that if the case can be heard on an expedited basis then there should be no basis for orders of this type to be granted by the Court.

Tullow Uganda considers the claim to be frivolous, vexatious and without merit and will oppose it and any applications for interim orders before the Uganda High Court. Tullow regards the 2015 Settlement as a full, final and legally binding settlement of its capital gains tax dispute. Moreover, on 18 June 2020 Tullow Uganda filed an application to the Uganda High Court to have Mr Wabyona's application of 15 May 2020 struck-out.

Any liability in respect of the claim will remain with the Retained Group following Completion.

10. Related party transactions

The related party transactions that were entered into by Tullow during the financial years ended 31 December 2019, 31 December 2018 and 31 December 2017 are referred to in Tullow's annual report and accounts for the financial years ended 31 December 2019, 31 December 2018 and 31 December 2017 respectively. There were no new related party transactions entered into by Tullow between 31 December 2019 and the Latest Practicable Date that were material to Tullow.

11. Tullow Share Schemes

Tullow operates the following share incentive schemes:

11.1 Tullow Incentive Plan

Overview

The Tullow Incentive Plan (the "TIP") is the primary senior executive incentive arrangement. The TIP is designed to better align executive and Shareholder interests and ensure the Group's remuneration arrangements are simple. Participants in the TIP generally do not participate in the Tullow ESAP (as defined in Section 11.2 of this Part VI (*Additional Information*)) other than in certain exceptional circumstances or on hiring a new employee to facilitate a buy-out of awards forfeited at a previous employer. As at the Latest Practicable Date, there were 29,199,340 awards outstanding under the TIP.

Awards made to Executive Directors under the TIP are granted subject to and in accordance with the terms of Tullow's Shareholder approved remuneration policy from time to time.

Eligibility

Any employee (including an Executive Director) of the Company and its subsidiaries is eligible to participate in the TIP at the discretion of the Group's Remuneration Committee (the "Remuneration Committee") in respect of a financial year, generally subject to their continued employment.

Individual limit/maximum participation amount

The aggregate value of cash and deferred share awards that an individual can receive or be awarded in respect of their participation in the TIP for any financial year must not normally exceed 400 per cent. of their salary at the beginning of the following financial year. TIP awards up to 200 per cent. of salary are 50 per cent. payable in cash and 50 per cent. payable in deferred shares that do not vest for up to five years; and any part of a TIP award in excess of 200 per cent. of salary is awarded in deferred shares that do not vest for up to five years (i.e. the maximum cash award under the TIP is 100 per cent. of salary).

Performance conditions

The value of a participant's cash bonus and deferred share awards under the TIP for any financial year will depend on the satisfaction in the period prior to grant of performance conditions set by the Remuneration Committee.

Payment of cash bonuses

Cash bonuses will normally be paid as soon as practicable following the end of the relevant financial year in respect of which an individual participates in the TIP, subject to the achievement of the applicable performance conditions.

An employee who has left employment for a prescribed "good leaver" reason during the relevant financial year, or prior to the date on which a cash bonus is paid, will remain entitled to receive a cash bonus in respect of that year (which may be paid on a pro rata basis where applicable).

At the discretion of the Remuneration Committee, any portion of the cash component of a TIP award can be satisfied by granting deferred shares with a vesting date set by the Committee being not earlier than the first anniversary of grant.

Grant and vesting of deferred share awards

The Remuneration Committee may normally grant deferred share awards within six weeks following the Company's announcement of its results for any period, subject to the achievement of the applicable performance conditions. It may also grant deferred share awards at any other time when the Remuneration Committee considers there are exceptional circumstances which justify the granting of deferred share awards.

Deferred share awards normally vest five years after grant for Executive Directors and three years after grant for all other participants, subject to continued employment of the relevant participant, but the Remuneration Committee has discretion to set different vesting periods.

Dividend equivalents

The Remuneration Committee may decide that participants will receive a payment (in cash and/or shares) on or shortly following receipt of shares under their deferred share awards, of an amount equivalent to the dividends that would have been paid on those shares between the time when the deferred share awards were granted and their vesting. This amount may assume the reinvestment of dividends.

Leaving employment—deferred share awards

Deferred share awards generally will not be granted to a participant who ceases to hold employment for any reason before the award is granted.

If, following the grant of an award, a participant ceases to be employed before the relevant award has vested then the award shall ordinarily lapse immediately upon such cessation.

However, where the reason for cessation of employment is death, injury, disability, retirement or redundancy, the participant's employing company or the business for which they work being sold out of the Company's group or in other circumstances at the discretion of the Remuneration Committee ("Good Leaver Reasons"):

(a) vested deferred share awards granted as options in respect of a financial year shall subsist and continue to be exercisable for 12 months; and

(b) unvested deferred share awards may vest earlier than if the participant's employment had not ceased for Good Leaver Reasons. In general, unvested deferred share awards will vest at the normal time, unless the Remuneration Committee determines otherwise, in which case deferred share awards will vest on the date the participant leaves. If the participant leaves by reason of retirement vesting will normally be the earlier of the normal vesting date and three years after retirement. If the participant dies deferred share awards will normally vest immediately. The share awards may then be exercised within a 12-month period from the date of vesting and shall lapse thereafter.

Corporate events

In the event of a corporate event resulting in a change of control or winding up of the Company (not being an internal corporate reorganisation):

(a) outstanding unvested deferred share awards shall vest early, at the time of such event and, in the case of options, shall be exercisable for one month from notification (in the case of a general offer) and for one month from the court sanction or winding-up (as applicable), after such period they will lapse;

(b) outstanding vested deferred bonus share awards granted as options shall be exercisable for one month after such notification or event (as applicable), after such time they shall lapse;

(c) if the event occurs during the financial year, and before the cash bonus is paid, the participant will instead be paid earlier and at the time of such event, based on a curtailed performance period and on a time pro-rated basis; and

(d) if the event occurs following the end of the financial year, but before the cash bonus is paid, the participant shall receive the cash bonus as soon as practicable thereafter.

If a demerger, special dividend or other similar event is proposed which, in the opinion of the Remuneration Committee, would affect the market price of shares to a material extent, cash bonuses will generally not be affected but the Remuneration Committee may decide to adjust outstanding deferred share awards or may decide that awards will vest on such terms as the Remuneration Committee may determine, and can either vest prior to such event or upon the event occurring, as the Remuneration Committee may determine. Vested deferred share awards, to the extent unexercised, shall lapse at the end of the period preceding the demerger, special dividend or other similar event. Outstanding deferred share awards may also be adjusted in the event of a variation of share capital.

Clawback

The Remuneration Committee may decide, within five years of the end of any financial year in respect of which an individual participates in the TIP, that any cash bonus paid or deferred share award granted to them will be subject to clawback: (i) where there has been a misstatement of the Company's financial results or of its oil or gas reserves; (ii) if an error has occurred in assessing the performance conditions that determined the amount of the cash bonus or deferred share award; (iii) where there is a catastrophic failure of environmental, health or safety risk management; or (iv) if the participant's employment is terminated for misconduct.

Share limits

Awards granted under the TIP may be satisfied by newly issued shares in the Company, treasury shares or shares purchased on the stock markets in which the Company's shares are traded.

In any 10-calendar year period, the Company must not issue (or grant rights to issue) more than 10 per cent. of the issued ordinary share capital of the Company in issue at that time under all of the Company's share plans or more than 5 per cent. of the issued ordinary share capital of the Company in issue at that time under executive share plans.

11.2 Tullow Employee Share Award Plan

Overview

The Tullow Employee Share Award Plan (the "ESAP") is the Company's primary non tax-advantaged all employee incentive arrangement. Participants in the ESAP generally do not participate in the TIP (as defined in Section 11.1 of this Part VI (*Additional Information*)) other than in certain exceptional circumstances or on hiring a new employee to facilitate a buy-out of awards forfeited at a previous employer. As at the Latest Practicable Date, there were 38,421,747 awards outstanding under the ESAP.

Eligibility

Any employee of the Company and its subsidiaries is eligible to participate in the ESAP (unless determined otherwise by the Remuneration Committee), generally subject to their continued employment. Any individual who participates in the Tullow Incentive Plan will generally not receive ESAP awards in the same financial year other than in certain exceptional circumstances or on hiring a new employee to facilitate a buy-out of awards forfeited at a previous employer.

Grant and vesting of awards

The Remuneration Committee may grant awards to acquire shares within six weeks following the Company's announcement of its results for any period. The Remuneration Committee may also grant awards at any other time when the Remuneration Committee considers there are exceptional circumstances which justify the granting of awards.

The Remuneration Committee may also decide to grant cash-based awards of an equivalent value to share-based awards or to satisfy share-based awards, in cash, but would normally only do so when the delivery of shares is impracticable. An award must not be granted under the ESAP after 7 May 2023.

No payment is required for the grant of an award. Awards are not transferable, except on death.

The Remuneration Committee may determine any vesting period whatsoever, however, they normally determine that awards vest after three years. Options may not be exercised after the tenth anniversary of grant. The vesting of awards is not subject to conditions other than continued employment or leaving as a good leaver (as explained below).

Individual limit

An employee must not receive awards in any financial year over shares having a market value in excess of 50 per cent. of their annual base salary in that financial year (or 75 per cent. of such salary in exceptional circumstances, as determined by the Remuneration Committee). The Remuneration Committee will have regard to the seniority of employees within the Company's group and the personal performance in determining the value of shares over which they receive awards in any financial year.

Dividend equivalents

The Remuneration Committee may decide that participants will receive a payment (in cash and/or shares) on or shortly following the vesting of their awards (or their exercise in the case of options), of an amount equivalent to the dividends that would have been paid on those shares between the time when the awards were granted and their vesting. This amount may assume the reinvestment of dividends.

Leaving employment

Unvested awards will normally lapse upon a participant ceasing to hold employment.

However, if a participant ceases to be an employee because of their death, injury, disability, retirement, redundancy, their employing company or the business for which they work being sold out of the Group or in other circumstances at the discretion of the Remuneration Committee, then their unvested award will vest earlier when they leave employment, unless the Remuneration Committee determines otherwise, in which case vesting will occur on the normal vesting date. When an award vests on cessation of employment it will normally be time pro-rated to reflect any reduced period between grant and vesting.

Corporate events

In the event of a corporate event resulting in a change of control or winding up of the Company (not being an internal corporate reorganisation), awards will vest early on notification of such event. Awards are exercisable within one month of such notification and shall lapse at the end of that period. Vesting shall be subject to pro-rating of the award to reflect the reduced period of time between their grant and vesting, although the Remuneration Committee can decide not to pro-rate an award if it regards it as inappropriate to do so in the particular circumstances.

If a demerger, special dividend or other similar event is proposed which, in the opinion of the Remuneration Committee, would affect the market price of shares to a material extent, then the Remuneration Committee may decide that awards will vest earlier on such basis as the Remuneration Committee may determine and during such period preceding such event or on such event as the Remuneration Committee determines. If the Remuneration Committee determines that the award shall vest then it shall apply a pro rata reduction to the number of shares, unless it determines this to be inappropriate.

11.3 UK Share Incentive Plan

Overview

The Share Incentive Plan (the "SIP") is a UK tax favoured share plan. The SIP is comprised of three elements and the Board may decide which of these to offer to eligible employees:

(a) "Free Shares" are shares in Tullow which may be allocated to an employee for nil consideration. The market value of Free Shares allocated to any employee in any UK tax year may not exceed £3,600 or such other limit as may be permitted by the relevant legislation. Free Shares may be allocated to employees equally or on the basis of salary, length of service or hours worked, or on the basis of performance.

(b) "Partnership Shares" are shares an employee may purchase out of their pre-tax earnings. The market value of Partnership Shares which an employee can buy in any tax year may not exceed £1,800 (or 10 per cent. of the employee's salary, if lower), or such other limit as may be permitted by the relevant legislation. Salary deductions may be accumulated over a period of three months and then used to buy shares at the lower of the market value of the shares at either the start of the accumulation period or the purchase date.

(c) "Matching Shares" are free shares which may be allocated to an employee who buys Partnership Shares. The Board may allocate up to two Matching Shares for every Partnership Share purchased (or such other maximum ratio as may be permitted by the relevant legislation).

Awards under the SIP may not be made after 7 May 2023.

As at the Latest Practicable Date, there were 2,723,359 Tullow Shares held pursuant to the trust established in connection with the SIP.

Eligibility

Employees of the Company and any designated participating subsidiary who are UK resident taxpayers are eligible to participate. The Board may allow non-UK tax resident taxpayers to participate. The Board may require employees to have completed a qualifying period of employment of up to 18 months in order to be eligible to participate.

Retention of shares

The trustee of the SIP trust will award Free Shares and Matching Shares to employees and hold those shares on behalf of the participants. Free Shares and Matching Shares must usually be retained by the trustee of the SIP trust for a period of at least three years after award.

The trustee will acquire Partnership Shares on behalf of participants and hold those shares on behalf of the participants. Employees can withdraw Partnership Shares from the SIP trust at any time, but this will usually cause any associated Matching Shares to be forfeited.

An employee will be treated as the beneficial owner of shares held on their behalf by the trustee of the SIP.

The Board may decide that awards of Free Shares and/or Matching Shares will be forfeited if participants cease to be employed by a company in the Group within three years from the grant of those awards unless they leave by reason of death, injury, disability, redundancy, retirement, or if the business or company for which they work ceases to be part of the Group. In any of those cases, the participants will be required to withdraw their shares from the SIP.

If an employee ceases to be employed by the Group at any time after acquiring Partnership Shares, he will be required to withdraw those Partnership Shares from the SIP trust.

Corporate events

In the event of a general offer being made to Shareholders, participants will be able to direct the trustees how to act in relation to their shares. In the event of a corporate reorganisation, any shares held by participants may be replaced by equivalent shares in a new holding company.

Dividends on shares held by the trustee of the SIP

Any dividends paid on shares held by the trustee of the SIP on behalf of participants may be either used to acquire additional shares for employees or distributed to participants.

Overall plan limits

The SIP must be operated so that, in any 10-calendar year period, the Company must not issue (or grant rights to issue) more than 10 per cent. of the issued ordinary share capital of the Company in issue at that time under all of the Company's share plans.

Variation of capital

In the case of a variation of the share capital of the Company, shares held in the SIP will be treated in the same way as other shares. In the event of a rights issue, participants will be able to direct the trustees of the SIP on how to act on their behalf.

The Tullow Oil Irish Share Incentive Plan (the "Irish SIP")

The Tullow Oil Irish Share Incentive Plan is similar to the SIP, although it differs in certain respects to comply with Irish legislation. As at the Latest Practicable Date, there were 375,652 Tullow Shares held pursuant to the trust established in connection with the Irish SIP.

Deferred share bonus plan (the "DSBP")

Prior to the introduction of the TIP any bonus earned by the Company's Executive Directors that exceeded 75 per cent. of base salary was deferred under the Company's Deferred Share Bonus Plan into nil cost share options. Vested awards normally remain exercisable until 10 years from grant. All options have now vested under the DSBP. As at the Latest Practicable Date, there were no options outstanding under the DSBP.

Tullow Oil 2000 Executive Share Option Scheme ("ESOP")

This plan was replaced by the TIP. The ESOP expired in 2010, however, certain employees still have exercisable options under the ESOP. As at the Latest Practicable Date, there were 6,241,009 options outstanding under the ESOP, exercisable until 2023.

12. No significant change

12.1 The Retained Group

Save as set out below, there has been no significant change in the financial or trading position of the Retained Group since 31 December 2019, being the date to which the last published audited financial information of the Group was prepared.

Tullow announced its full year results for the year ended 31 December 2019 on 12 March 2020. In these results, the Directors assessed that the Group was a going concern for 12 months from the date of approval of Tullow's annual report and accounts for the financial year ended 31 December 2019. At the time of issuing Tullow's annual report and accounts for the financial year ended 31 December 2019, there were unprecedented market conditions relating to COVID-19 and the oil price, as described in Section 8 (*Industry update*) of Part I (*Letter from the Executive Chair of Tullow*) of this document. These conditions increased the risk that the Group may not be able to sufficiently progress planned portfolio management activities, as a result of which its lenders may not approve the bi-annual RBL Facility redetermination liquidity assessments or covenant amendments if subsequently required. Therefore, the Directors concluded that there is a material uncertainty, that may cast significant doubt, that the Group will be able to operate as a going concern.

As announced on 3 April 2020, Tullow completed the March 2020 RBL Facility redetermination with US$1.9 billion of debt capacity approved by the lending syndicate. As a result, Tullow had approximately US$700 million liquidity headroom of undrawn facilities and free cash at the start of the second quarter of the year.

As previously announced, Tullow is now targeting capital expenditure of approximately US$300 million in 2020 (down from approximately US$350 million). Savings have been identified primarily through the deferral of activities across the portfolio and through savings that can be realised by ongoing farm-down activities.

As announced on 21 April 2020, Rahul Dhir has been appointed as Chief Executive Officer and an Executive Director of the Group from 1 July 2020.

On 23 April 2020, the Company announced the Transaction, with Tullow Uganda and Total Uganda having signed the Sale and Purchase Agreement.

12.2 Interests

There has been no significant change in the financial or trading position of the Interests since 31 December 2019, being the date to which the historical financial information relating to the Interests as set out in Part III (*Financial Information on the Interests*) of this document relates, which has been extracted without material adjustment from the consolidation schedules and supporting analysis that underlie the audited consolidated financial information of Tullow for the financial year ended 31 December 2019.

13. Working capital

Tullow is of the opinion that the Retained Group does not have sufficient working capital for its present requirements, which is for at least the next 12 months from the date of this document (the "Working Capital Period").

Overview

The scenarios referred to in this section have been prepared on the basis of (i) what the Directors believe to be the reasonable worst case scenario based on the average realisable oil price being US$25/bbl for the 2020 financial year, US$35/bbl for the 2021 financial year and US$45/bbl for the 2022 financial year; (ii) what the Directors believe to be the base case scenario based on the average realisable oil price being US$35/bbl for the 2020 financial year, US$45/bbl for the 2021 financial year and US$55/bbl for the 2022 financial year; and (iii) the Convertible Bonds due in July 2021 and the 2022 Senior Notes due in April 2022 being repaid in full on the contractual maturity dates (rather than refinanced in accordance with past practice).

Even if Completion occurs, in both the reasonable worst case scenario and the base case scenario, the Retained Group may fail to pass the Liquidity Forecast Test and/or breach the RBL Gearing Covenant during the Working Capital Period. This could result in an event of default under the RBL Facility allowing the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights, which could in turn trigger cross-defaults under the other financing arrangements of the Retained Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes) by mid to end of June 2021. The amount repayable should the lenders under the RBL Facility decide to exercise their right to accelerate the RBL Facility and the Retained Group's creditors exercise their right to trigger a cross-default under the Retained Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Retained Group's borrowings is immediately repayable, was US$3.255 billion as at 31 May 2020. But for such circumstances, the Retained Group would expect to have sufficient working capital for its requirements during the Working Capital Period. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

It is not possible for the Board, particularly in light of current trading conditions and, especially, the COVID-19 pandemic and the high levels of market volatility and uncertainty arising therefrom, to determine with absolute certainty any forecasted non-compliance with the RBL Gearing Covenant or the quantum of any forecasted liquidity shortfall which could result in a failure to pass the Liquidity Forecast Test. However, based on current trading expectations, the Retained Group's working capital projections in respect of a potential breach of the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020 and a potential failure to pass the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination are set out below, each in the reasonable worst case scenario and the base case scenario and assuming that Completion occurs.

30 June 2020 RBL Gearing Covenant test

The Retained Group does not expect to breach the RBL Gearing Covenant for the 12-month period ending on 30 June 2020.

September 2020 Liquidity Forecast Test

The Retained Group expects to pass the Liquidity Forecast Test in respect of the September 2020 RBL Facility redetermination.

31 December 2020 RBL Gearing Covenant test, timing and action plan

In the reasonable worst case scenario, the Retained Group forecasts a Covenanted Net Debt to Consolidated EBITDA ratio of 5.0 times in respect of the financial covenant 12-month testing period ending 31 December 2020 (such that the Retained Group would exceed the permitted RBL Gearing Covenant test ratio by 1.5 times as a result of a forecasted Consolidated EBITDA shortfall of approximately US$280 million). Further, in the base case scenario, the Retained Group forecasts a Covenanted Net Debt to Consolidated EBITDA ratio of 3.9 times in respect of the financial covenant 12-month testing period ending 31 December 2020 (such that the Retained Group would exceed the permitted RBL Gearing Covenant test ratio by 0.4 times as a result of a forecasted Consolidated EBITDA shortfall of approximately US$100 million).

An event of default under the RBL Facility as a result of this breach of the RBL Gearing Covenant will arise when:

(a) Tullow delivers to the relevant lenders a notification of non-compliance with the RBL Gearing Covenant, which is required to be delivered as soon as Tullow's audited financial statements for the year ended 31 December 2020 are available but no later than 30 April 2021; and

(b) a subsequent 75-day period expires without the Company having resolved the non-compliance, either by: (i) seeking agreement with its lenders to waive the non-compliance or (ii) procuring a cash subscription for Tullow Shares and/or receipt of an injection of cash by way of certain subordinated debt such that the relevant ratio is satisfied by reducing Covenanted Net Debt accordingly. The Company would be prohibited from drawing any further available amounts under the RBL Facility during this period.

In this scenario and unless the Retained Group is able to agree an amendment or waiver with the relevant lenders, there will be an event of default under the RBL Facility by mid-June 2021.

The Group continues to closely monitor cash flow forecasts and to explore actions to improve its forecast financial position and maintain compliance with its external debt facilities, including securing amendments to or waivers of covenants if necessary.

In order to address the potential breach of the RBL Gearing Covenant for the 12-month testing period ending 31 December 2020, the Group's management expects that it will seek an amendment of the covenant in advance of the relevant assessment, or a waiver, such that the RBL Gearing Covenant will not be breached. The Directors believe that the Retained Group would be able to secure such an amendment or waiver, which would be both consistent with past practice and the Directors' reasonable expectation of the commercial interests of the Retained Group and its lenders. As at the date of this document, the Group's management has not approached the relevant lenders to discuss an amendment to or waiver of the 31 December 2020 RBL Gearing Covenant. The Directors note that agreeing an amendment or waiver of the RBL Gearing Covenant would require the approval of the relevant majority of lenders under the RBL Facility. This action is therefore outside the control of the Retained Group.

March 2021 Liquidity Forecast Test, timing and action plan

The Group's working capital projections forecast a potential liquidity shortfall during the 18-month period relevant to the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination. This potential liquidity shortfall in relation to the Group's financial commitments of approximately US$600 million in the reasonable worst case scenario, and approximately US$130 million in the base case scenario, is first forecasted to arise in April 2022, which is within the 18-month testing period from April 2021 to

September 2022 inclusive that is relevant to determining whether the Company will pass the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination. If the Company is unable to demonstrate to the reasonable satisfaction of the relevant majority of its lenders under the RBL Facility that it has, or will have sufficient funds available to meet the Group's financial commitments for the 18-month testing period from April 2021 to September 2022 inclusive (for example, because the lenders under the RBL Facility do not take into account the potential positive impact of the mitigating actions described below), and the Company is unable to cure the forecast liquidity shortfall within 90 days following the date on which it becomes aware that it has not passed the Liquidity Forecast Test, there will be an event of default under the RBL Facility by the end of June 2021.

The Directors note that passing the Liquidity Forecast Test in respect of the March 2021 RBL Facility redetermination would require satisfying the relevant majority of lenders in relation to the Retained Group's liquidity. This is therefore outside the control of the Retained Group. As at the date of this document, the Group's management has not approached the relevant lenders in respect of the March 2021 RBL Facility redetermination.

The Group's management expects that it will investigate refinancing of either or both of the Convertible Bonds due in July 2021 and the 2022 Senior Notes due in April 2022 to address the forecasted liquidity shortfall in April 2022. Such refinancing would be both consistent with past practice and the Directors' reasonable expectation of the commercial interests of the Retained Group and its creditors. As at the date of this document, the Group's management has not undertaken any steps in respect of refinancing either the Convertible Bonds due in July 2021 or the 2022 Senior Notes due in April 2022. The Directors note that any debt refinancing is outside the control of the Retained Group and therefore the Directors cannot be confident that any such refinancing could be delivered, or sufficiently progressed, such that the lenders of the RBL Facility would take it into account in respect of the Liquidity Forecast Test at the March 2021 RBL Facility redetermination.

The Group's management also continues to evaluate strategic opportunities and engage in discussions with third parties with a view to raising in excess of US$1 billion proceeds from portfolio management of which the proceeds from the Transaction would be a significant part. For example, the Group is in discussions with third parties with respect to farming down its interests in the South Lokichar onshore development in Kenya. There can be no assurance that it will be possible to make any such disposals and it is not possible at this stage to give an indication of the potential proceeds which the South Lokichar onshore development or any other assets may realise. Accordingly, the Directors cannot be confident that these disposals can be achieved.

In addition, the Group's management is considering taking one or more of the following actions which the Group's management believes could be progressed sufficiently by the end of March 2021 such that the Retained Group would be able to pass the Liquidity Forecast Test at the March 2021 RBL Facility redetermination:

(a) independently of the amendment or waiver expected to be sought in respect of the potential breach of the RBL Gearing Covenant for the 12-month testing period ending 31 December 2020, securing a new liquidity facility from banks or capital markets investors. While the Directors believe that the Group has strong relationships with its lending banks and a track record of accessing capital markets, there can be no assurance that the Retained Group's lending banks or any other investor would agree to provide such a facility. In addition, the Directors note that, in light of the increased regulatory oversight and requirements under which banks and investors operate and the volatility of oil prices, there has been a reduction in certain banks' and investors' willingness and ability to lend to or invest in entities in the oil and gas industry. Accordingly, the Directors cannot be confident that the Retained Group will be able to secure or obtain additional financing on commercially acceptable terms, or at all;

(b) as part of the March 2021 RBL Redetermination, seeking to agree more beneficial technical and/or economic assumptions with its lenders or seeking to amend the commercial terms of the RBL Facility in order to increase debt capacity. The Directors note that these actions would require the approval of the relevant majority of lenders under the RBL Facility and are therefore outside of the control of the Retained Group. As such, the Directors cannot be confident that this could be achieved;

(c) initiating a further rationalisation of its cost base (in addition to measures already implemented since December 2019) through a further reduction of general and administrative costs. The Directors are reasonably confident that a further reduction of approximately US$25 million per annum can be achieved from 2021 onwards; and

(d) initiating cuts to discretionary capital investment (in addition to measures already implemented since December 2019 and, for example, by focussing on maintenance of producing fields only and substantially reducing investment in development, exploration and appraisal activities) and deferring decommissioning expenditure. The Directors note that initiating cuts to discretionary capital investment and deferring decommissioning expenditure: (i) may require approval from third parties including its commercial partners and there can be no assurances that these approvals will be obtained; and (ii) are dependent to an extent upon the Retained Group's ability to execute strategic opportunities in relation to asset disposals and there can be no assurance that it will be possible to make any such disposals. Accordingly, the Directors cannot quantify any savings that may arise out of such measures or be confident that any such measures will be successful.

While the Directors would consider the above actions in parallel, the Directors cannot be certain that these mitigating actions will be capable of addressing the forecasted liquidity shortfall in the time available, or at all.

Event of default

The potential events of default in respect of the 31 December 2020 RBL Gearing Covenant and/or the March 2021 RBL Facility redetermination would arise concurrently (i.e. by mid to end June 2021).

Any event of default under the RBL Facility as described above would allow the lenders under the RBL Facility, at their discretion, to cancel the RBL Facility and demand that all outstanding borrowings under the RBL Facility be repaid and/or enforce their security rights. This would in turn trigger creditors' rights to call cross-defaults under the other financing arrangements of the Retained Group (namely the Convertible Bonds, the 2022 Senior Notes and the 2025 Senior Notes). Enforcement action taken by the relevant trustees on instruction of the bondholders could result in the entirety of the Retained Group's borrowings potentially becoming immediately repayable by:

(a) around mid-June 2021 (in the event of a breach of the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020); and

(b) around the end of June 2021 (in the event that the Retained Group does not pass the Liquidity Forecast Test at the March 2021 RBL Facility redetermination).

The amount outstanding under the Retained Group's RBL Facility which could be required to be repaid following an event of default under the RBL Facility as described above was US$1.505 billion as at 31 May 2020. The amount repayable should the Retained Group's creditors exercise their right to trigger a cross-default under the Retained Group's other financing arrangements, resulting in the borrowings under such arrangements being accelerated such that the entirety of the Retained Group's borrowings, including the amount outstanding under the Retained Group's RBL Facility, is immediately repayable, was US$3.255 billion as at 31 May 2020. The financial information set out in this paragraph has been extracted without material adjustment from the Company's unaudited management accounts for the month ended 31 May 2020.

Implications

If a breach of the RBL Gearing Covenant in respect of the 12-month testing period ending on 31 December 2020 were to occur or the Retained Group were not to pass the Liquidity Forecast Test at the March 2021 RBL Facility redetermination, and the Retained Group were unable to negotiate amendments or waivers to its covenants, the Retained Group might have to enter into insolvency proceedings and counterparties to material contracts might seek to exercise termination rights under those contracts. In such circumstances, the ability of the Retained Group to continue trading would depend upon the Retained Group being able to negotiate a refinancing proposal with its creditors and, if necessary, that proposal being approved by Shareholders. Whilst the Board would seek to negotiate such a refinancing proposal with its creditors, there is no certainty that the creditors would engage with the Board in those circumstances. There would therefore be a significant risk of the Retained Group entering into insolvency proceedings, which the Directors consider would likely result in limited or no value being returned to Shareholders.

14. CONSENTS

Deloitte LLP is registered to carry out audit work in the UK and Ireland by the Institute of Chartered Accountants in England and Wales and has given, and not withdrawn, its written consent to the inclusion of its report on the unaudited pro forma statement of net assets of the Retained Group set out in Section 2 of Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document in the form and context in which it appears.

Barclays has given, and not withdrawn, its written consent to the issue of this document with references to its name being included in the form and context in which they appear.

J.P. Morgan Cazenove has given, and not withdrawn, its written consent to the issue of this document with references to its name being included in the form and context in which they appear.

Robey Warshaw has given, and not withdrawn, its written consent to the issue of this document with references to its name being included in the form and context in which they appear.

TRACS has given, and not withdrawn, its written consent to the inclusion of its report set out in Part VII (*Mineral Expert's Report*) of this document, and to the issue of this document with references to its name being included in the form and context in which they appear and has authorised those parts of this document which comprise its report for the purposes of paragraph 13.4.1R(6) of the Listing Rules.

15. Documents available for inspection

Copies of the following documents will be available on the Company's website (www.tullowoil.com) (other than document (g) below) or for physical inspection during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) at the offices of the Company at 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT from the date of this document up to and including the date of the General Meeting and for the duration of the General Meeting:

(a) the Articles;

(b) the audited financial statements of the Tullow Group for each of the financial years ended 31 December 2017, 2018 and 2019;

(c) the report of Deloitte set out in Section 2 of Part IV (*Unaudited Pro Forma Financial Information of the Retained Group*) of this document;

(d) the consent letters referred to in Section 14 of this Part VI (*Additional Information*);

(e) the report of TRACS set out in Part VII (*Mineral Expert's Report*) of this document;

(f) this document and the Form of Proxy; and

(g) the Sale and Purchase Agreement.

PART VII—MINERAL EXPERT'S REPORT

The Directors
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London W4 5XT

Barclays Bank PLC (acting through its investment bank) ("Barclays")
5 The North Colonnade
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J.P. Morgan Securities plc (which conducts its UK investment banking business as J.P. Morgan Cazenove) ("J.P. Morgan Cazenove")
25 Bank Street
Canary Wharf
London E14 5JP

18 June 2020

Mineral Expert's Report for Tullow Oil Uganda Assets

In response to your request, TRACS International Limited ("TRACS") has completed an independent evaluation of certain oil assets in Uganda in which Tullow Oil plc ("Tullow") has an interest (the "Uganda assets") (the "Report").

The Report is prepared as a mineral expert's report in accordance with paragraph 13.4.6R of the Listing Rules made by the Financial Conduct Authority for the purposes of Part VI of the Financial Services and Markets Act 2000, as amended (the "UK Listing Rules") and paragraphs 131 to 133 of the European Securities and Markets Authority update of the CESR Recommendations regarding the consistent implementation of the European Commission's Regulation No 809/2004 (ESMA/2013/319). We understand that the Report will be reproduced in Tullow's circular dated on or around the date of this letter (the "Circular"), in connection with Tullow's proposed sale of the Uganda assets, which is a Class 1 transaction under the UK Listing Rules.

For the purposes of the Report. we have estimated a range of reserves and resources as at 13 March 2020 (the "Effective Date"), based on data and information available up to that date. No site visits have been undertaken by TRACS for the purposes of producing the Report. So far as we are aware, no material changes have occurred since the Effective Date, the omission of which would make the Report misleading.

The Report was prepared in accordance with standard geological and engineering methods generally accepted by the oil and gas industry, in particular the June 2018 SPE/WPC/AAPG/SPEE Petroleum Resources Management System ("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 was founded in 1992, and currently has over 50 petroleum engineers, geoscientists and petroleum economists working from two office locations. 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 Limited (an independent company). All contracts and ownership rights to prior work performed by AGR TRACS were retained by TRACS during that transaction.

The Uganda assets evaluation was performed by senior TRACS staff with a combined 120+ 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 the 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 mapping 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 the Report represents the independent view of TRACS. The risking of contingent and prospective resources has been done in accordance with the LSE/AIM Guidance note for Mining, Oil and Gas Companies—June 2009.

TRACS has carried out this work using the PRMS as the standard for classification and reporting and in accordance with reserves and resource definitions presented in the PRMS. A summary of the PRMS is found in Appendix B of the Report.

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

Neither TRACS nor the individuals who are responsible for authoring the Report, nor any directors of TRACS, have at the date of the Report, nor have had within the previous two years, any economic or beneficial interest (present or contingent) in Tullow. TRACS, the individuals responsible for authoring the Report and the directors of TRACS are independent of Tullow, its directors, senior management and its other advisers, have no economic or beneficial interest (present or contingent) in Tullow or in any of the mineral assets being evaluated and are not remunerated by way of a fee that is linked to the value of Tullow.

TRACS has reviewed the information contained in the Circular which relates to information contained in the Report and confirms that the information presented is true, accurate, complete, not inconsistent with the Report and, if the information in the Circular has been extracted from the Report, that information has been properly extracted.

The Report is for the use of Tullow and its shareholders and, in their capacity as Tullow's sponsors for the purposes of the Circular, Barclays and J.P. Morgan Cazenove. TRACS has given, and not withdrawn, its written consent to the inclusion of the Report in the form set out in the Circular, and to the issue of the Circular with references to its name being included in the form and context in which they appear and has authorised those parts of the Circular which comprise its report for the purposes of paragraph 13.4.1R(6) of the UK Listing Rules. The Report may not be used for any other purpose without TRACS' prior written approval, provided that there shall be no restriction on Tullow, Barclays or J.P. Morgan Cazenove disclosing the Report where required by law, court order or regulatory authority or in connection with any judicial, regulatory or arbitral proceedings or for the purposes of resolving any actual or potential dispute or claim.

Yours faithfully,

TRACS International Limited
Dr. Mike Wynne

EXECUTIVE SUMMARY

Tullow Oil requested TRACS to provide a Competent Persons Report (CPR) for the Uganda fields and discoveries in the Tullow portfolio. The fields and discoveries are located onshore Uganda - except Kingfisher, which is situated offshore in Lake Albert but planned to be developed from onshore.

The region includes 18 fields and discoveries under three licences which have been divided into four categories for this report as listed below:

Category	Field	Licence
Tilenga Phase 1	Jobi-Rii	EA-1
	Gunya	EA-1
	Ngiri	EA-1
	Kasamene	EA-2
	Wahrindi	EA-2
	Kigogole	EA-2
	Nsoga	EA-2
	Ngiri Terrace	EA-1
	Rii 2	EA-1
Remaining Tilenga fields	Ngege	EA-2
	Ngara	EA-2
	Jobi East	EA-1
	Lyec	EA-1
	Mpyo	EA-1
Kingfisher	Kingfisher	EA-3
Kaiso-Tonya fields	Waraga	EA-2
	Mputa	EA-2
	Nzizi	EA-2

Summary of Uganda assets

Total is the current operator for the EA-1 Licence, Tullow for the EA-2 licence and CNOOC is the operator of the EA-3 licence. Total, CNOOC and Tullow (collectively termed the “Contractor”) hold equal interests in all three Ugandan licences. Therefore Tullow currently has a working interest (WI) of 33.33% in all licences. The Uganda National Oil Company (UNOC) will buy in for 15% from the production licence award date, 5% from each International Oil Company (IOC). Tullow’s share will then reduce to 28.33% for all licences. For this report a 28.33% Tullow working interest of Gross is assumed.

The reservoirs are made up of good to varying quality, high permeability sands generally of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The hydrocarbon accumulations are contained within a series of stratigraphic units. The layering and faulting results in different fluid contacts within and between fields resulting in a complex system of stacked pools. The fields are underlain by what is believed to be a well-connected aquifer system.

There is currently no production from the Ugandan fields. There has been extensive exploration and appraisal across the fields with numerous well tests. There are currently 76 exploration and appraisal wells (plus 19 sidetracks) in the region. The fluids are generally part of a low energy system with viscosities ranging from a few centipoise in Kingfisher to 100’s of centipoise in Jobi East.

The Tilenga area will be developed in phases. The development concept for Phase 1 requires a Central Processing Facility (CPF) situated in the EA1 area with all Phase 1 fields tied back to the Tilenga CPF. Once the oil has been processed it will be exported to the planned Kabaale refinery and then onwards to the East African coast via the East African Crude Oil Pipeline (EACOP). The remaining fields will be developed through the Tilenga CPF in further phases to be defined.

Kingfisher will be developed utilising its own CPF. The oil will be sent via an electrically heated pipeline, to the planned Kabaale refinery approximately 50km north east of the Kingfisher field and then onwards via EACOP to the East African coast.

Both developments will utilise waterflood with the possibility of polymer flood being used at a later date (polymer flooding is not part of Phase 1).

Tullow provided TRACS with their reservoir models (static and dynamic where applicable) and development plans/assumptions for new developments, historical costs and future cost assumptions.

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, and carrying out or requesting additional model runs where felt justified.

The 2018 SPE PRMS Guidelines for reserves and resource reporting have been applied in this report.

FEED studies for the facilities and pipelines are complete. The final investment decision (FID) is dependent on the resolution of commercial negotiations that are currently ongoing. Due to the uncertainty in the outcome of commercial negotiations no reserves have been identified for the Uganda fields. All resources carried are classified as Contingent Resources.

Contingent Resources

The Tullow contingent resources (CR) for the Uganda fields are based on three main components:

- Fields which are included in Phase 1 of the development concepts for Tilenga and Kingfisher are classified as Development Pending (DP)
- The key oil projects with no firm plans for development, plus gas associated with the Phase 1 oil projects, are categorised as Development on Hold (DoH). This includes polymer flood and development of additional fields/reservoirs not included in Phase 1
- The development of gas resources (e.g. gas caps) has not been studied or feasibility tested and would potentially require additional facilities to develop the gas. These resources have been classified as Development not Viable (DnV).

The DP resources have been assessed at a hub and licence level to take into account dependencies and independencies associated with the different field developments.

The aggregated profiles at field, license block and project levels were generated by an in-house tool which was constructed for the Tilenga Phase 1 and Kingfisher projects. The type curves of oil rate vs cumulative oil production were created from the outputs of dynamic simulation models of Phase 1 fields supplied by Tullow. These formed input into the type curve tool to generate a range of production forecasts profiles which satisfy the CPFs constraints of the Phase 1 development plans.

For the remaining CR categories the results of simulation model reviews and analytical analysis was used to generate a range of recovery factors for each field which were then applied to the derived ranges of STOIIP and GIIP.

The total remaining Gross and Tullow Working Interest unrisked Contingent Resources for Uganda is given in the tables below. A conversion rate of 167 boe/MMscf is assumed. The Tullow Working Interest resources are based on a 28.33% share of the Gross CR.

A Chance of Commerciality (COC) has been assessed for all Contingent Resources. These are presented in the table below but not applied to the resource numbers (i.e. they are unrisked)

CR Classification (Oil)	Project	Gross (MMbbls)			Attributable to Tullow (MMbbls)			CoC
		1C	2C	3C	1C	2C	3C	
Development Pending	Phase 1	555.9	910.0	1436.6	157.5	257.8	407.0	50.0%
Development on Hold	Polymer flood	184.3	292.7	462.3	52.2	82.9	131.0	37.5%
Development on Hold	Remaining oil	212.6	445.9	736.4	60.2	126.3	208.6	25.0%
Total All CR Categories		**952.8**	**1648.6**	**2635.3**	**269.9**	**467.1**	**746.6**	

Tullow Uganda Contingent Resource summary – Oil Unrisked

CR Classification (Gas)	Project	Gross (Bscf)			Attributable to Tullow (Bscf)			CoC
		1C	2C	3C	1C	2C	3C	
Development on Hold	Solution gas	83.2	138.9	223.3	23.6	39.3	63.2	25.0%
Development not Viable	Gas caps	28.1	53.2	91.4	8.0	15.1	25.9	12.5%
Total All CR Categories		**111.3**	**192.1**	**314.6**	**31.5**	**54.4**	**89.1**	

Tullow Uganda Contingent Resource summary – Gas Unrisked

CR Classification (Total)	Project	Gross (MMboe)			Attributable to Tullow (MMboe)			CoC
		1C	2C	3C	1C	2C	3C	
Development Pending	Phase 1	555.9	910.0	1436.6	157.5	257.8	407.0	50.0%
Development on Hold	Polymer flood	184.3	292.7	462.3	52.2	82.9	131.0	37.5%
Development on Hold	Remaining oil	212.6	445.9	736.4	60.2	126.3	208.6	25.0%
Development on Hold	Solution gas	13.9	23.1	37.2	3.9	6.6	10.5	25.0%
Development not Viable	Gas caps	4.7	8.9	15.2	1.3	2.5	4.3	12.5%
Total All CR Categories		**971.4**	**1680.6**	**2687.7**	**275.2**	**476.1**	**761.4**	

Tullow Uganda Contingent Resource summary – Total boe Unrisked

A summary of the risked Contingent Resources applying the CoCs to the unrisked CR are presented in the table below.

Contingent Resources	**Gross**			**Attributable to Tullow**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Oil (MMbbls)	400.2	676.2	1075.8	113.4	191.6	304.8
Gas (Bscf)	24.3	41.4	67.2	6.9	11.7	19.0
Total (Boe)	**404.3**	**683.1**	**1087.0**	**114.5**	**193.5**	**307.9**

Tullow Uganda Contingent Resource summary – Risked

Contents

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1 INTRODUCTION

1.1 OVERVIEW

The Uganda fields and discoveries in the Tullow portfolio are located onshore Uganda with the exception of the Kingfisher field which is situated offshore in Lake Albert, although planned to be developed from onshore. The region includes 18 fields and discoveries under three licences; EA1, EA2 and EA3. Figure 1-1 shows an overview of the location of the assets.

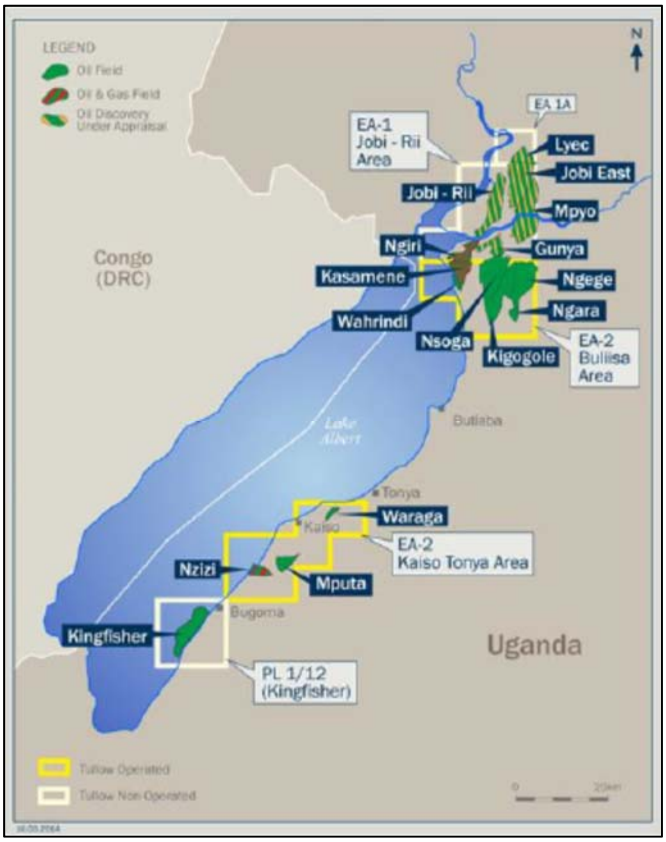


Figure 1-1 Uganda assets Location Map

Throughout this report three main development areas will be referred to: Tilenga, Kingfisher and Kaiso-Tonya. The Kingfisher and Kaiso-Yonya areas are shown in Figure 1-1. The Tilenga area is in the northern region and consists of the fields in the Jobi Rii and Bullisa areas as illustrated in Figure 1-1.

The reservoirs in the fields are made up of good to varying quality, high permeability sands generally of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The hydrocarbon accumulations are contained within a series of stratigraphic units. The layering and faulting results in different fluid contacts within and between fields resulting in a complex system of stacked pools. The fields are underlain by what is believed to be a well-connected aquifer system.

There is currently no production from the Ugandan fields. There has been extensive exploration and appraisal across the fields with numerous well tests. There are currently 76 exploration and appraisal wells (plus 19 sidetracks) in the region. The fluids are generally part of a low energy system with viscosities ranging from a few centipoise in Kingfisher to 100's of centipoise in Jobi East.

1.2 DEVELOPMENT PLANS AND CURRENT STATUS

Total is the current operator for the EA-1 Licence, Tullow for EA-2 licence and CNOOC is the operator of the EA-3 licence. Total is also the project leader of EACOP. Total, CNOOC and Tullow hold equal interests in all three Ugandan licences. Therefore Tullow currently has a working interest of 33.33% in all licences. The Uganda National Oil Company (UNOC) will buy in for 15% from the production licence award date, 5% from each IOC. Tullow's share will then reduce to 28.33% for all licences. For this report a 28.33% Tullow working interest of Gross is assumed.

The Uganda assets are planned to be developed in phases. Phase 1 of the development involves a subset of the Tilenga fields and the Kingfisher field.

The Tilenga development concept for Phase 1 requires a Central Processing Facility situated in the EA1 area with all Phase 1 fields tied back to the Tilenga CPF. Once the oil has been processed it will be exported to the planned Kabaale refinery and then onwards to the East African coast via the East African Crude Oil Pipeline (EACOP). The remaining fields will be developed through the Tilenga CPF in further phases to be defined.

Kingfisher Phase 1 will be developed utilising its own CPF. The oil will be sent via an electrically heated pipeline, to the planned Kabaale refinery approximately 50km north east of the Kingfisher field and then onwards via EACOP to the East African coast.

Both developments will utilise waterflood developments with the possibility of polymer flood being used at a later date (polymer flooding is not part of Phase 1).

Significant Technical work towards project sanction has been completed for the Phase 1 project. Comprehensive technical work has been performed and Field Development Plans (FDPs) have been submitted to the Ugandan authorities. Front End Engineering Design (FEED) had been completed for both Tilenga and Kingfisher project areas and the Phase 1 development concept scope has been tendered under an EPC contract.

FEED has also been completed on the midstream project (refinery and export pipeline to East African coast).

Although the Phase 1 project is well positioned for project sanction from a technical point of view the main challenge is in landing the key commercial contracts and agreements which are required before sanction can be taken. In September 2019 Total E&P suspended all technical activities related to the establishment of an export pipeline and upstream operations due to disagreements over tax with the Uganda Revenue Authority. There has recently been signs that the oil companies and Uganda authorities are ready to resume discussions to resolve the commercial issues and resume operations. However, at the current time the future of the Tilenga and Kingfisher projects remain uncertain.

2 SUMMARY OF RESERVES AND CONTINGENT RESOURCES

2.1 TOTALLED FOR UGANDA

2.1.1 Reserves

No Reserves have been estimated for the Ugandan assets.

2.1.2 Contingent Resources

The total remaining Gross and Tullow Working Interest unrisked Contingent Resources (CR) for Uganda is given for oil in Table 2-1, for gas in Table 2-2 and total (boe) in Table 2-3. A conversion rate of 167 boe/MMscf is assumed. The Working Interest resources to Tullow are based on a 28.33% share of the Gross CR.

A Chance of Commerciality (CoC) for each category/project is also presented but has not been applied to the resources in the tables below. Section 8.3 presents the risked CR.

The range of recovery factors associated with Phase 1 Tilenga resources are 18.6% to 27.2% with a mid-case of 22.6% and 22.5% to 37.5% with a mid-case of 30.7% for the Kingfisher Phase 1 development. For all resources (i.e. all phases of development) the range of recovery factors are 23.7% to 36.4% with a mid-case of 30.1%. This also accounts for an extension to 50 years for the Phase 1 resources.

CR Classification (Oil)	Project	Gross (MMbbls)			Tullow Working Interest (MMbbls)			CoC
		1C	2C	3C	1C	2C	3C	
Development Pending	Phase 1	555.9	910.0	1436.6	157.5	257.8	407.0	50.0%
Development on Hold	Polymer flood	184.3	292.7	462.3	52.2	82.9	131.0	37.5%
Development on Hold	Remaining oil	212.6	445.9	736.4	60.2	126.3	208.6	25.0%
Total All CR Categories		**952.8**	**1648.6**	**2635.3**	**269.9**	**467.1**	**746.6**	

Table 2-1 Tullow Uganda Contingent Resource summary - Oil

CR Classification (Gas)	Project	Gross (Bscf)			Tullow Working Interest (Bscf)			CoC
		1C	2C	3C	1C	2C	3C	
Development on Hold	Solution gas	83.2	138.9	223.3	23.6	39.3	63.2	25.0%
Development not Viable	Gas caps	28.1	53.2	91.4	8.0	15.1	25.9	12.5%
Total All CR Categories		**111.3**	**192.1**	**314.6**	**31.5**	**54.4**	**89.1**	

Table 2-2 Tullow Uganda Contingent Resource summary - Gas

CR Classification (Total)	Project	Gross (MMboe)			Tullow Working Interest (MMboe)			CoC
		1C	2C	3C	1C	2C	3C	
Development Pending	Phase 1	555.9	910.0	1436.6	157.5	257.8	407.0	50.0%
Development on Hold	Polymer flood	184.3	292.7	462.3	52.2	82.9	131.0	37.5%
Development on Hold	Remaining oil	212.6	445.9	736.4	60.2	126.3	208.6	25.0%
Development on Hold	Solution gas	13.9	23.1	37.2	3.9	6.6	10.5	25.0%
Development not Viable	Gas caps	4.7	8.9	15.2	1.3	2.5	4.3	12.5%
Total All CR Categories		**971.4**	**1680.6**	**2687.7**	**275.2**	**476.1**	**761.4**	

Table 2-3 Tullow Uganda Contingent Resource summary – Total boe

2.2 TOTALLED BY FIELD

2.2.1 Reserves

No Reserves have been estimated for the Ugandan assets

2.2.2 Contingent Resources

A breakdown of total unrisked CR by field is given for oil in Table 2-4 and for gas in Table 2-5.

Field	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Jobi-Rii	238.6	438.7	648.1	67.6	124.3	183.6
Gunya	118.5	196.1	327.0	33.6	55.5	92.6
Ngiri	170.3	264.5	417.4	48.3	74.9	118.2
Kasamene	41.6	62.5	94.7	11.8	17.7	26.8
Wahrindi	5.5	9.8	16.1	1.6	2.8	4.6
Kigogole	52.2	87.5	140.4	14.8	24.8	39.8
Nsoga	63.9	98.1	150.2	18.1	27.8	42.5
Ngiri Terrace	43.0	61.0	91.4	12.2	17.3	25.9
Rii 2	15.5	34.6	57.8	4.4	9.8	16.4
Kingfisher	153.2	267.7	464.9	43.4	75.8	131.7
Ngege	2.6	9.4	28.0	0.7	2.7	7.9
Ngara	1.7	2.6	5.6	0.5	0.7	1.6
Jobi East/Lyec	14.6	40.4	68.1	4.1	11.4	19.3
Mpyo	0.0	25.9	50.1	0.0	7.3	14.2
Waraga	19.9	28.9	44.1	5.6	8.2	12.5
Mputa	10.7	19.0	28.6	3.0	5.4	8.1
Nzizi	1.0	2.0	3.0	0.3	0.6	0.9

Table 2-4 Uganda Contingent Resource summary by field – Oil

Field	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Jobi-Rii	23.4	43.0	66.3	6.6	12.2	18.8
Gunya	7.5	12.6	21.2	2.1	3.6	6.0
Ngiri	26.1	42.4	68.4	7.4	12.0	19.4
Kasamene	9.3	14.8	22.9	2.6	4.2	6.5
Wahrindi	0.8	1.5	2.5	0.2	0.4	0.7
Kigogole	3.1	5.4	8.8	0.9	1.5	2.5
Nsoga	4.9	9.5	17.1	1.4	2.7	4.8
Ngiri Terrace	9.4	14.8	22.7	2.7	4.2	6.4
Rii 2	0.8	1.9	3.2	0.2	0.5	0.9
Kingfisher	17.4	30.4	52.8	4.9	8.6	14.9
Ngege	1.3	2.9	7.4	0.4	0.8	2.1
Ngara	0.1	0.2	0.5	0.0	0.1	0.1
Jobi East/Lyec	0.4	1.2	2.0	0.1	0.3	0.6
Mpyo	0.0	0.6	1.2	0.0	0.2	0.3
Waraga	2.0	3.0	4.5	0.6	0.8	1.3
Mputa	0.8	1.4	2.1	0.2	0.4	0.6
Nzizi	4.0	6.5	10.9	1.1	1.8	3.1

Table 2-5 Uganda Contingent Resource summary by field – Gas

3 GENERAL METHODOLOGY AND ASSUMPTIONS

3.1 OVERVIEW OF ASSETS

Tullow Oil requested TRACS to provide Competent Persons Report (CPR) for the Uganda fields and discoveries in the Tullow portfolio. The assets audited are listed in Table 3-1 and have been divided into four categories in this report:

1. Fields that form the basis of the Tilenga Phase 1 project
2. Kingfisher
3. Remaining fields/discoveries in Tilenga
4. Remaining fields/discoveries in Kaiso-Tonya

	Field	Licence	Operator
Tilenga Phase 1	Jobi-Rii	EA-1	Total
	Gunya	EA-1	Total
	Ngiri	EA-1	Total
	Kasamene	EA-2	Total
	Wahrindi	EA-2	Total
	Kigogole	EA-2	Total
	Nsoga	EA-2	Total
	Ngiri Terrace	EA-1	Total
	Rii 2	EA-1	Total
Kingfisher	Kingfisher	PL 1/12	CNOOC
Remaining Tilenga fields	Ngege	EA-2	Total
	Ngara	EA-2	Total
	Jobi East	EA-1	Total
	Lyec	EA-1	Total
	Mpyo	EA-1	Total
Kaiso-Tonya fields	Waraga	EA-2	Total
	Mputa	EA-2	Total
	Nzizi	EA-2	Total

Table 3-1 Summary of Uganda assets

The fields and discoveries are located onshore Uganda except Kingfisher which is situated offshore in Lake Albert (Figure 1-1).

3.2 OVERVIEW OF PROCESS

Tullow provided TRACS with their reservoir models (static and dynamic where applicable) and development plans/assumptions for new developments, 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, and carrying out or requesting additional model runs where felt justified.

3.3 RESERVES AND CONTINGENT RESOURCES REPORTING

3.3.1 Reserves

No reserves were identified for the Uganda assets. This section is for information only.

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 3-2.

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

Table 3-2 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.

3.3.2 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 3-3.

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 3-3 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.

3.4 GEOSCIENCE AND DYNAMIC MODEL REVIEW

Resource estimates for the Uganda discoveries were supported by static models. The models were generated by the various operators and made available to TRACS. These, along with associated dynamic models, were reviewed by TRACS.

Tullow has undertaken probabilistic STOIIP calculations using an @RISK spreadsheet approach supported by the static reservoir models. The models were used to define gross rock volumes for reservoir zones and regions of the fields.

TRACS reviewed the inputs and methodology to the @Risk calculations as the basis for STOIIP estimates. Where the input/methodology was reasonable this was accepted. Where the input/methodology was not accepted TRACS derived their own assessment by making revisions to the static models and/or the inputs to the @Risk sheets.

TRACS reviewed seismic and well data, and available models to validate input ranges and derive their own understanding. The @Risk decks were updated with the TRACS view and ranges of in place volumes estimated for each field, by panel and by zone.

Mid case simulation models were reviewed for the Phase 1 developments to develop an understanding of the recovery factors for the different reservoirs. Low and High case simulation models (where available) were reviewed to understand ranges of recovery factors. Note that these models did not include the uncertainty in relative permeabilities and Sor, the most significant dynamic uncertainties. However, these were cross checked with fractional flow analysis to ensure consistency.

The results of simulation model reviews and analytical analysis was used to generate a range of recovery factors for each field.

3.5 HUB PRODUCTION PROFILES

Tilenga phase 1 development project consists of nine fields: Jobi-Rii, Ngiri, Gunya, Kigogole, Nsoga, Kasamene, Wahrindi, Ngiri-Terrace and Rii-2. The aggregated profiles at field, licence block and project levels were generated by an in-house tool which was constructed for the Tilenga Phase 1 project. The type curves of oil rate vs cumulative oil production were created from the outputs of Mid Case dynamic simulation models of nine fields for the inputs into the type curve tool to generate 2C forecast profiles which is able to satisfy the Central Processing Facility (CPF) constraints of the Phase 1 development plan (BOD7). The type curves from Mid Case dynamic models are adjusted to form the inputs to the type curve tool to generate 1C and 3C forecast profiles, respectively. Total recovery was calibrated using STOIIP and recovery factors created using the processes described in section 2.3. This approach is also applied for the Kingfisher Phase 1 project.

3.6 DEVELOPMENT PLANS AND COST ESTIMATES

Whilst no economic assessment is reported in this version of the CPR the life of field cost data provided was reviewed for consistency and reasonableness. 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.

Well information was reviewed for the following areas in Uganda;

- Kingfisher
- Tilenga

Overall time and cost estimates for well construction were completed in a robust manner using offset information, global benchmarking and existing in-house costs in combination with market tendering exercises.

3.7 PRODUCTION FORECASTS AND OPERATING EFFICIENCY

The facility operating efficiency is 93% and the well operating efficiency is 95%, according to the Phase 1 development plan. The production forecasts of Phase 1 fields were generated from the in-house type curve tool.

3.8 COMMERCIAL PARAMETERS

3.8.1 Economic evaluation

No economic evaluation was performed for the purpose of this CPR. However the Operator's economic model was provided as a source of annual cost data.

3.8.2 Risked volume and value

A Chance of Commerciality (COC) has been assessed for all Contingent Resources (CR). This is applied to the unrisked CR volumes to generate risked CR volumes.

3.8.3 Licence award and Working Interest

Award date	EA1	EA2	EA3
Exploration Licence	Jan-04	Jan-02	Jan-04
Production Licence	Aug-16	Aug-16	Feb-12

Partner share	EA1	EA2	EA3
Exploration	100%	85%	100%
Upstream Development	85%	85%	85%
Upstream Revenue	85%	85%	85%
UNOC back-in from:	PL award	EL award	PL award

Tullow currently hold a 33.33% share in EA1, EA2 and EA3. The Uganda National Oil Company (UNOC) will buy in for 15% from the award date in the tables above, 5% from each IOC. Tullow's share will then reduce to 28.33%. For this report a 28.33% Tullow working interest of Gross is assumed.

The Tilenga (EA-1 and EA-2) production licence was awarded in 2016 and will expire at the end of 2046 based on the 25 year development/production period and an assumed 5 year extension as understood by TRACS to be defined in the PSC.

The Kingfisher (EA-3) production licence was awarded in 2012 and will expire at the end of 2042 based on the 25 year development/production period and an assumed 5 year extension as understood to be defined in the PSC.

3.8.4 Shrinkage, yield factors and boe equivalents

No crude shrinkage factor from wellhead to sales is applied.

A conversion rate of 167 boe/MMscf is assumed.

4 TILENGA PHASE 1 FIELDS

4.1 OVERVIEW OF HUB

4.1.1 Introduction/Hub background

The Tilenga areas comprises of 14 discoveries which exhibit oil and gas in shallow sandstone reservoirs mostly between 300-1000 m deep. An overview of the fields in the Tilenga area is shown in Figure 1-1. The Tilenga area consists of licence areas EA1 (operated by Total) and EA2 (operated by Tullow).

The Tilenga area will be developed in phases. The Phase 1 project consists of 9 fields (see Table 3-1). Significant Technical work has been completed on the Phase 1 project including field development plans (FDPs) for each field and detailed engineering design (FEED).

The development concept for Phase 1 requires a Central Processing Facility (CPF) situated in the EA1 area with all Phase 1 fields tied back to the CPF. Once the oil has been processed it will be exported to the planned Kabaale refinery and then onwards to the East African coast. The remaining fields will developed through the Tilenga CPF in further phases to be defined.

This section presents the TRACS assessment of the resources associated with the Phase 1 fields.

4.1.2 Development plans and cost estimates

The oil production and water injection wells will be located at 34 well pads within the EA-1 and EA-2 licences. The current plan is for a total of 412 wells to be drilled for the development of the Phase 1 fields, 199 producers and 213 water injectors. A summary of the wells by field is shown below.

Field	Producers	Water Injectors	Total
Jobi-Rii	54	68	122
Ngiri	29	27	56
Gunya	26	26	52
Kigogole/ Nsoga	68	70	138
Kasamene/ Wahrindi	10	10	20
Ngiri_Terrace_Rii2	12	12	24
Total	**199**	**213**	**412**

Table 4-1 Tilenga area wells

From the well pads production will be sent to a Central Processing Facility (CPF) via a buried pipeline network. Water will be returned to the well pads for re-injection. To connect to the northern fields, including Jobi-Rii, production and water injection pipelines must cross Victoria Nile River. The CPF, operational camp and support base ("industrial area") will be located outside of the Murchison Falls National Park (MFNP), south of the Victoria Nile, in EA-1. After processing the oil will be transferred to a tank farm to be located within the CPF. The CPF design capacity will based peak annual average production rates of:

- Oil, 190,000 bbl/d
- Gas, 30 MMscf/d
- Gross liquids, 710,000 bbl/d
- Produced water treatment, 650,000 bbl/d
- Water injection, 720,000 bbl/d

An export pipeline, the East African Crude Oil pipeline (EACOP) will deliver Tilenga oil to the planned Kabaale refinery (via the Transportation Pipeline System, TPS) and then onwards to the East African coast via the Export Pipeline System (EPS). Only the former is part of the project scope and Capex. The JV partners will also pay a tariff to the pipeline company, to cover the transportation fee to Kabaale.

At the CPF all associated gas will be used to generate electrical power. The CPF will provide electrical power for the needs of Kabaale Pumping station, electrical heat tracing for the 100km, 24" feeder line between the

CPF and Kabaale and for the pipeline between Kabaale and first export pipeline heating station. The excess electrical power will be fed into the national electricity grid.

FEED studies for the facilities and pipelines are complete. FID is dependent on the resolution of commercial negotiations. For the purpose of this CPR the first oil date assumed is Q1 2023. Note that the start date of Phase 1 is uncertain given the current suspension of the project. Before the project was suspended the start date that was being targeted was Q4 2022. The start date used in this report is used as a reference date only. Unless the current issues between the oil companies and the government are resolved quickly the start date will be delayed.

Tullow provided a cost summary of the development Capex in the form of a slide pack from the "JVP Costs Workshop" held on 27th March 2019 and produced by the Operator. Tullow advised that all the costs were associated with the Phase I water flood project, Development Pending CR only. No more detailed information was available.

Capex $MM RT19	Past costs	Point forward 1/1/2019
Pre-2012 Exploration & Appraisal	1504	
2012 -2015 Exploration & Appraisal	1012	
Pre-development (2016-2018)	330	
Surface facilities		2238
○ **Industrial area**		1231
○ **Wellpads**		474
○ **Network & lake water abstraction**		189
○ **Project Management**		160
○ **Contingency**		184
Drillex		1156
○ **Wells construction**		842
○ **Rig moves, mob/demob**		87
○ **Technical allowances**		27
○ **Project Management**		201
Tilenga Feeder		148
Pre-Opex		216
Infra-field logistics		222
Other costs		349
Total	**2846**	**4327**

Table 4-2 Tullow development Capex

"Other costs" include G&A, PMT, studies, surveys, land acquisition and enabling infrastructure.

4.1.2.1 Well costs

Initial well durations for the Ugandan wells were based on Total E&P assets in Venezuela, with added factors for geological and technical content, Uganda environment and well complexity. Well timings fit well within a provided benchmarking study of land wells in Kenya, India and Uganda although there may be opportunity for performance optimisation during detailed planning and operations. Service and logistic cost are based on a previous campaign with 15% contingency costs. This is a reasonable approach to take. No detail was available for review of well design or well architecture.

Well costs provided were at a high level i.e. total cost per well. The provided rig day rates are within the range of costs seen in previous market enquiries. Additional breakdown was given for split of costs across service categories (Tangibles, Rig, Service & Consumables, overheads etc.). Service contracts were awarded following a market tender exercise with award on a bundled services agreement to give best value for services.

A ‘factory drilling’ approach has been introduced using multiple rigs with the objective to achieve contractual savings by bundling services and optimise drilling performance by batch operations. Bundled costs following ITT evaluation are presented at a high level with little granularity. Total followed an extensive tendering process leading to a super bundling approach resulting in documented commercial benefits. The results of the tendering process were not available to TRACS. Given the robust nature and range of the tendering process and contract awards well costs can be assumed accurate.

Taking in to account total well cost, robust tendering process and proportion of split between cost type well costs are within the expected range.

4.1.2.2 Facilities costs and Opex

The Operator advises that 98% of the surface facilities Capex is market-priced, binding firm offers for the Engineering, Procurement, Supply, Construct, Commission (EPSCC) contract. 90% of the Drillex is based on market price, 10% an estimate. On this basis if the scope is well defined the Capex forecast carries a relatively high level of accuracy. TRACS has not seen or reviewed these offers.

Certain Capex in Table 4-2 is for shared facilities and hence will be allocated between the licences:

- An amount for Tilenga shared facilities – Capex allocation to be based on the ratio of FID resources between EA-1 and EA-2 (N) and fixed at 79%:21%
- An amount for Kabaale shared facilities - Capex allocation to be based on the ratio of FID resources between EA-1, EA-2 (N) and EA-3, fixed at 65%:17%:18%

The remaining Capex, e.g. for wells and well pads, is dedicated to each licence area.

Tullow advised that the Operator had not provided the Capex breakdown between the above and that TOTAL were using the sum of CPF, pads and trunk lines in their surface facilities costs and pro-rating that at 75%:25% between EA-1 and EA-2. In the absence of any further information TRACS assume the Operator’s approach.

The resulting point forward phased Capex for each licence area, and as input to the Operators model, is shown below.

EA-1 Capex ($MM RT19)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Wells	49	125	149	104	102	33	-	-
Surface	564	668	613	179	90	71	24	8
Owners costs	25	26	25	2	2	1	-	-
Total	**638**	**818**	**787**	**286**	**194**	**105**	**24**	**8**

EA-2 Capex ($MM RT19)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Wells	11	27	27	92	110	82	-	-
Surface	188	223	204	60	30	24	8	3
Owners costs	10	10	10	2	2	1	-	-
Total	**208**	**259**	**240**	**154**	**142**	**107**	**8**	**3**

The sum of the EA-1 and EA-2 phased point forward Capex above (plus sunk costs in 2019) is slightly higher than that presented in the Operator’s cost workshop slides but is well within the accuracy of the forecast Capex.

The “JVP Costs Workshop” slides quote the annual Opex to be on average over field life, $222/year RT19, equating to $6.5/bl. At approximately 5% of the development Capex the annual Opex is high, but probably not unreasonable given the remoteness of the location, the immaturity of the in-country oil industry and necessary levels of Opex cost contingency. 65% of the cost is well/facility related and 35% personnel/ G&A. The annual Opex profile is approximately flat in real terms with peaks in years of periodic gas turbine overhauls and major shutdowns. It allows for power import from 2028 and a gradual reduction in personnel costs resulting from knowledge transfer to the Ugandan staff. Never-the-less TRACS would expect that savings would be made to the annual Opex as operational experience is gained.

Opex costs at shared facilities are allocated between the licences:

- Tilenga Shared Services – Opex allocation to be based on the ratio of yearly production between EA-1 and EA-2 (N)
- Kabaale Shared Services - Opex allocation to be based on the ratio of yearly production between EA-1, EA-2 (N) and EA-3.

In the Operators model whilst the EA1:EA2 production varies year-on-year the ratio of Surface Opex between EA1 and EA2 is exactly 75%:25% in every year. Tullow advised that the Operator had not provided the Opex for each of the Shared Services but that an explanation had been requested of TOTAL.

4.1.2.3 Decommissioning costs

Decommissioning costs are not included in the "JVP Costs Workshop" slides, but have been specified as a single cost per licence in the provided data. The Operator provided a breakdown on request:

Decommissioning cost, $MM RT19	EA1	EA2	Total
Surface	204	54	258
Wells	102	70	172
Total	**306**	**124**	**430**

Table 4-3 Operator provided decommissioning costs

An estimate of 8% of the surface development Capex has been assumed by the Operator for the surface facilities decommissioning costs and these appear to be on the low side and carry a high level of uncertainty given that there are no benchmark projects. The well abandonment cost at $0.4MM per well is reasonable compared to that carried by the EA-3 Operator, $0.9MM RT19 per well, given the well type.

Abandonment provision will be made from the year in which 50% of the expected economic recoverable oil is reached.

4.1.3 Chance of Commerciality for Phase 1

Based on the current status of the project (see Section 1.2) the Chance of Commerciality (CoC) of Phase 1 (Tilenga and Kingfisher) is estimated to be 50%. This is predominately a commercial risk reflecting the current suspension of the project.

4.1.4 Tilenga Phase 1 CR summary

The Tilenga fields to be developed as part of the Phase 1 development are presented in Table 3-1. All resources associated with the Tilenga Phase 1 development are categorised as CR Development Pending. The Development Pending resources are cut-off at end of 2046 which is the end of the Tilenga licences (EA1 and EA2).

The oil DP Contingent Resources by field and licence area for the Tilenga Phase 1 project are presented in Table 4-4. Note that there are no gas DP Contingent Resources as a gas sales solution still needs to be matured.

CR Classification (Oil)	Licence	Field	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
			1C	**2C**	**3C**	**1C**	**2C**	**3C**
Pending Development	EA1	Jobi Rii	115.4	217.7	341.2	32.7	61.7	96.7
		Ngiri	125.0	190.8	298.8	35.4	54.1	84.6
		Gunya	84.1	136.6	225.7	23.8	38.7	64.0
		Ngiri Terrace	31.4	43.9	64.8	8.9	12.4	18.4
		Rii2	7.9	18.9	35.8	2.2	5.4	10.1
		EA1 sub Total	**363.8**	**607.9**	**966.3**	**103.1**	**172.2**	**273.7**
	EA2	Nsoga	44.8	66.9	100.4	12.7	19.0	28.4
		Kigogole	32.0	53.4	81.6	9.1	15.1	23.1
		Kasamene	30.8	45.6	68.2	8.7	12.9	19.3
		Wahrindi	3.6	6.4	10.3	1.0	1.8	2.9
		EA2 Sub-Total	**111.2**	**172.2**	**260.5**	**31.5**	**48.8**	**73.8**
		Grand Total	**475.0**	**780.1**	**1226.7**	**134.6**	**221.0**	**347.5**

Table 4-4 Phase 1 Contingent Resources by field - oil

4.2 JOBI-RII FIELD

4.2.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Jobi-Rii**
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field consists of three fault-bound panels in a structural trap (dip and fault closure).
HCIIP estimate (MMstb)	Oil GIIP P90 – 990 MMstb 129 Bscf P50 – 1357 MMstb 177 Bscf P10 – 1779 MMstb 233 Bscf
Development type	Water flood development, to be followed by polymer flood.
Number of current production & injection wells	9E&A wells
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.2.2 Contingent Resources

4.2.2.1 Geoscience review

Introduction

Jobi-Rii is the largest field of the Tilenga Phase 1 project.

The Tilenga Phase 1 fields lie within the same ‘megastructure’. The hydrocarbon accumulations are contained within a series of stratigraphic units from H15 (at the base) to H30 (at the top). The reservoir is characterised by unconsolidated and highly permeable reservoirs deposited in a fluvio-lacustrine environment. The reservoirs have undergone only shallow burial. Structures tend to be tilted fault blocks with fault closure to the east and dip closure to the west. The trapping mechanism to the North and South are defined by a combination of dip and fault closure. The layering and faulting within the Tilenga fields results in different fluid contacts within and between fields resulting in a complex system of stacked pools. The fields are underlain by what is believed to be a well-connected aquifer system.

Jobi-Rii has been divided into three fault-bound panels (Figure 4-1): Main, North and South. The South panel has been treated separately from the main Jobi Rii field and is referred to as Rii-2 area (see Section 4.9). There are six wells in the Jobi-Rii structure, two wells in Rii-2 and one well off structure. Jobi-Rii has eight reservoir units (Figure 4-2) although not all are hydrocarbon-bearing in all panels.

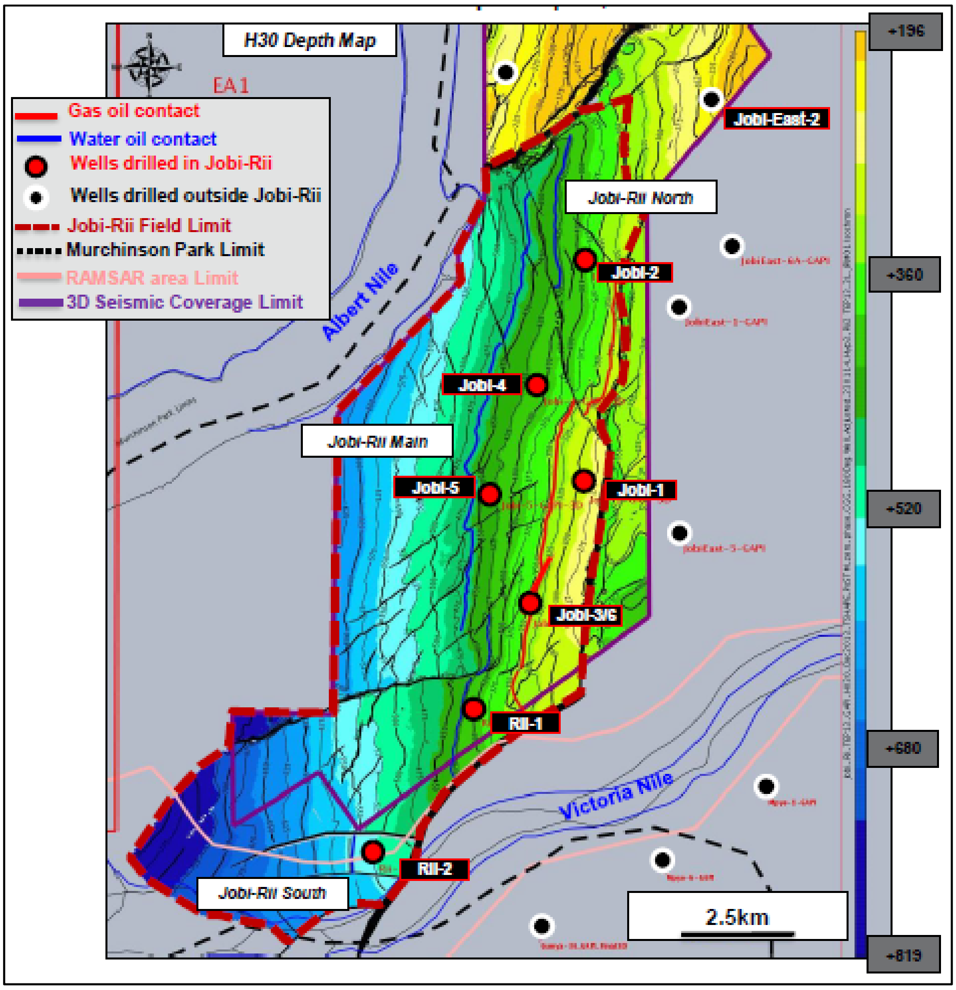


Figure 4-1 Jobi-Rii: Total depth map

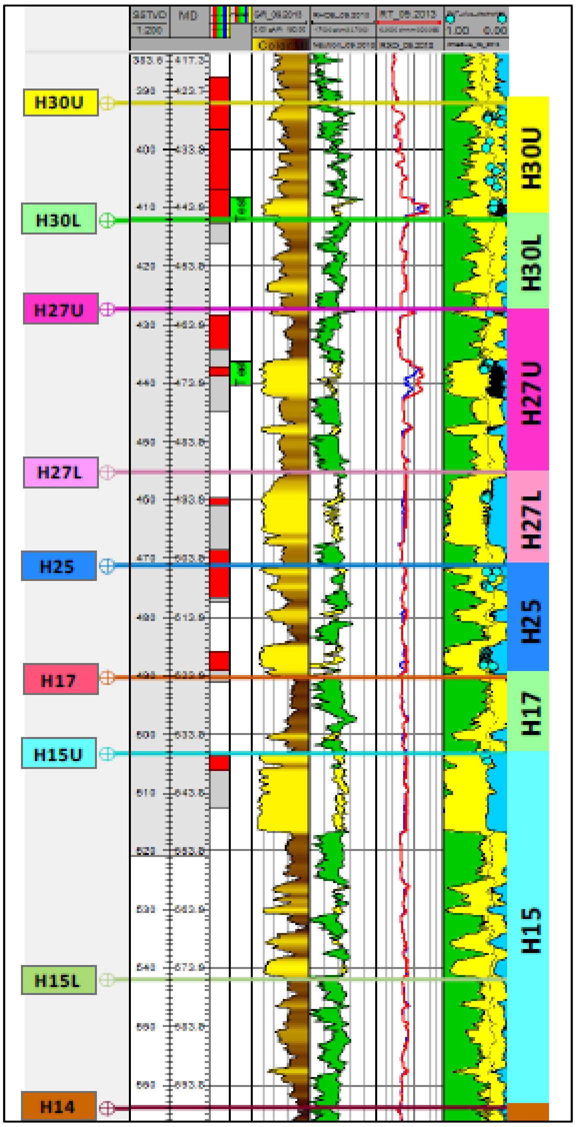


Figure 4-2 Jobi-2A well

The Tilenga Phase 1 fields are covered by high quality 3D seismic data with a vertical resolution of ~8-12m at reservoir level).TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

Static model

The seismic data set and its inversion products have been used extensively by the Operator as key inputs to the reservoir modelling workflow. The reservoir modelling workflow used by Total is common across all the Tilenga Phase 1 fields and uses inversion data, supported by a proprietary analogue data set, to populate static reservoir intervals. The inversion products and analogue data set were not made available to TRACS for this review TRACS reviewed the modelling workflow, resulting property grids and associated volumes.

The properties in the static model are directly related to the facies models generated by Total. The facies modelling workflow uses Architectural Elements (AEs) based on a variety of seismic attributes to define the large scale depositional environment and heterogeneity. An example from H27U is given in Figure 4-3. Small scale depositional sedimentary bodies and heterogeneity within the AEs are modelled using Lacustrine Facies Associations (AFLs); see Figure 4-4for the H27U example. The petrophysical properties are then distributed within this three dimensional facies framework.

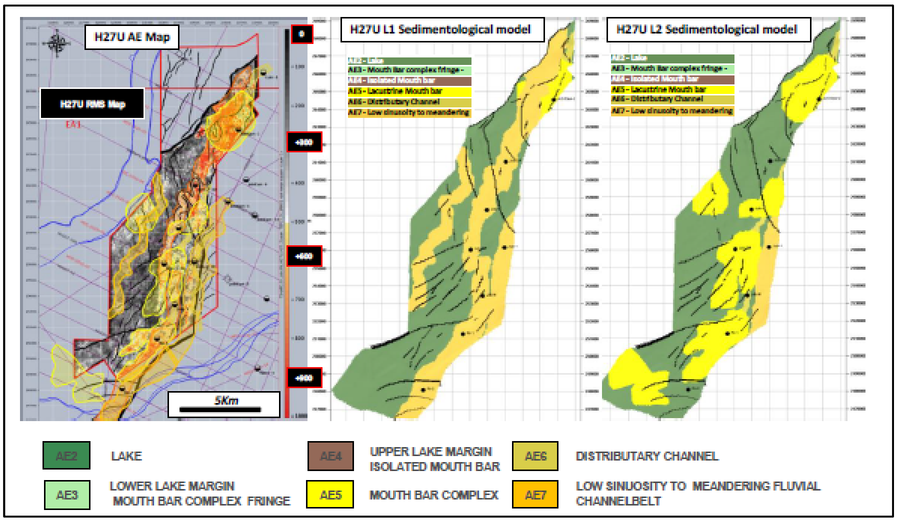


Figure 4-3 Jobi-Rii: H27U attribute map and AE interpretation

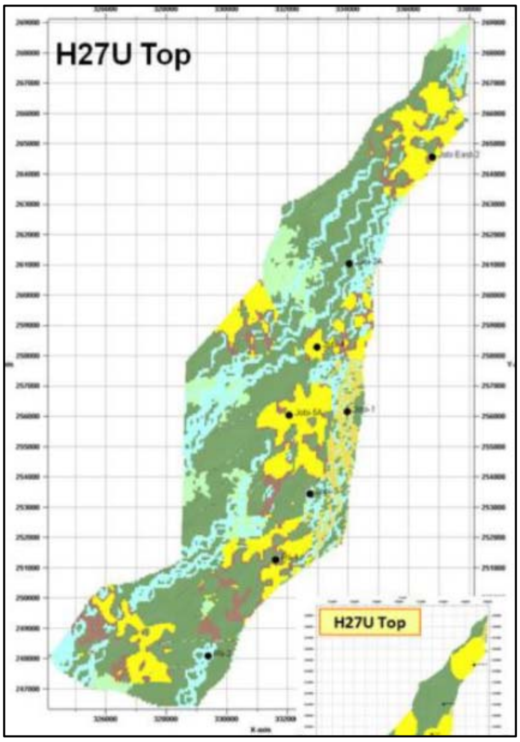


Figure 4-4 Jobi-Rii: H27U AFL distribution

It is clear that in this type of depositional environment rapid changes occur both laterally and vertically. While some of these variations may be captured by seismic data, others are not. The conceptual facies models (AEs) generated by Total represent a single, valid realisation but alternatives exist. It is also clear that well averages may not be representative of 3D averages.

The static modelling workflow is generally supported by TRACS but some anomalies have been identified. Although the reservoir properties encountered at the wells have been honoured in the upscaling and reservoir modelling process, it appears that for some well data only have a very local influence on the properties in the model. An example is shown for H27U near Jobi-2A where a NTG of 0 is observed at the well but changes to 1 in the adjacent cell. The well is located within a modelled channel belt (high NTG expected) but the rapid vertical changes seen in the well are not captured in the facies modelling around the well.

These apparent inconsistencies have been taken into account when generating the property input for the in place volume estimates.

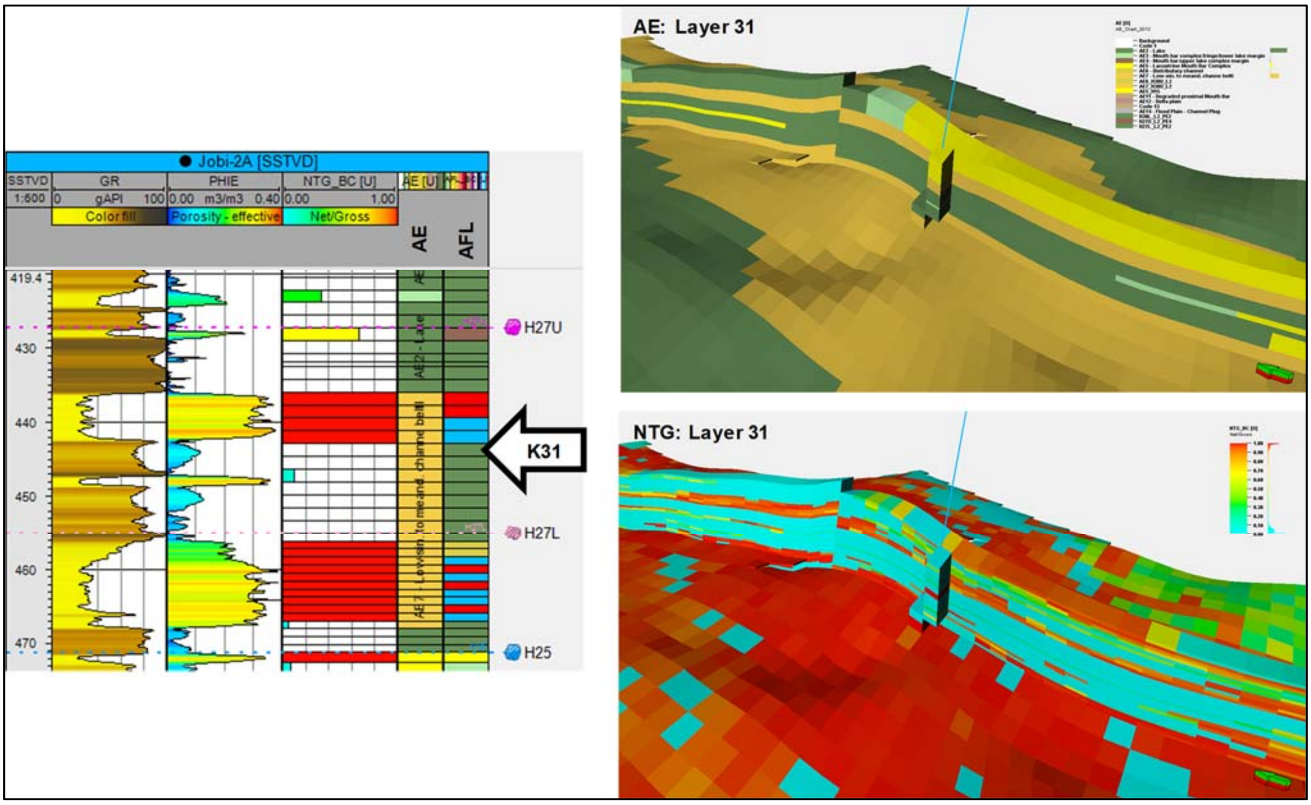


Figure 4-5 Jobi-2A facies model and NTG

4.2.2.2 Petrophysics review

General

A quick-look interpretation was carried out on one well in each field and the results compared to the interpretations supplied. Interpretation input parameters described in the PRRs were applied for the QL analysis (in this case for Jobi-1) and the results identified specifically which of the supplied data had been used for average properties. There was initially some mismatch in the properties quoted in the PRR compared with those obtained from the supplied data using the cut-offs quoted. It transpired the PHIE and SWT as named in the client data corresponded with the PHIE and SWE from the QL analysis. Once this was confirmed the relevant data set was used for comparison and the log interpretations as supplied were accepted.

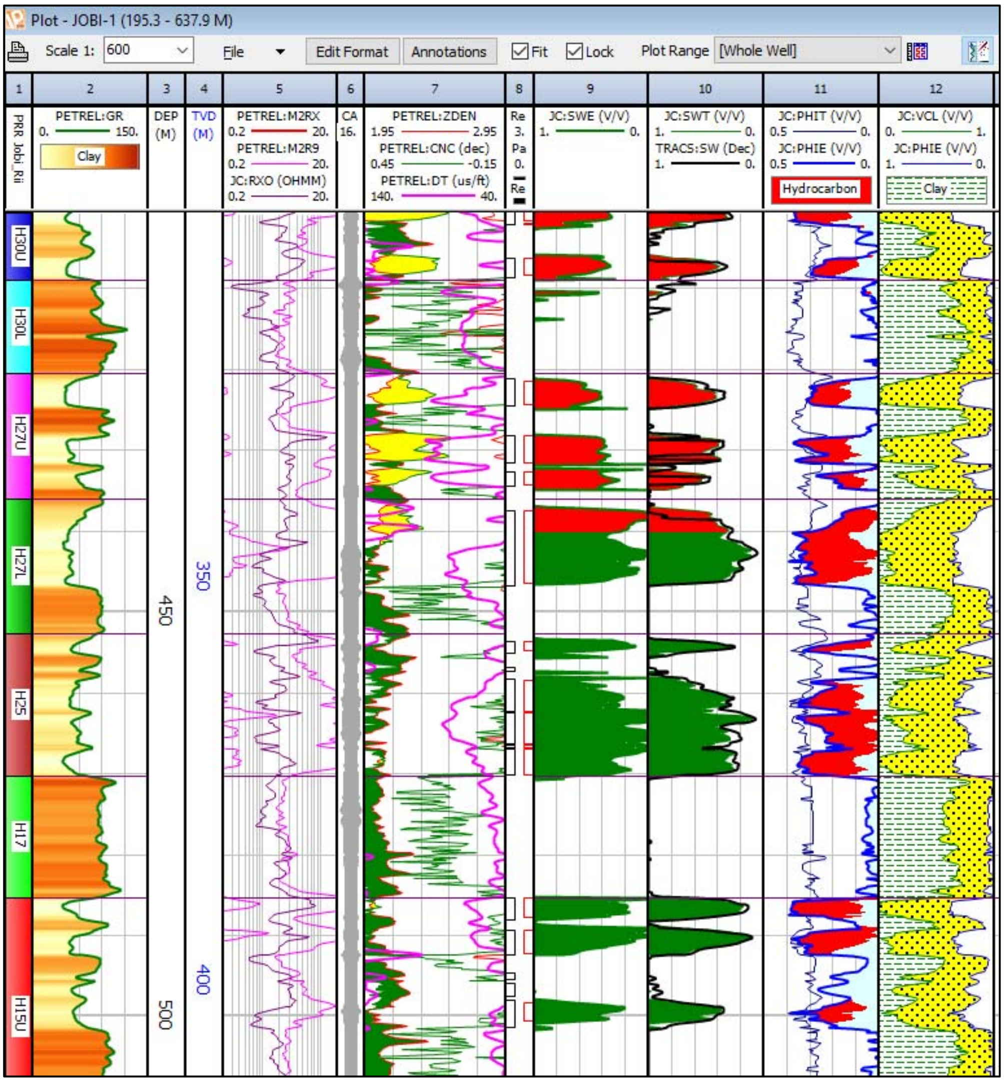


Figure 4-6 QL interpretation compared to client data confirming that client "SWT" is consistent with reproduced SWE

Average properties for the wells are consistent with those quoted in the PRR and this data was used to verify the property ranges modelled.

NTG

Average NTG varies both between reservoir units and within any reservoir unit over the field. The highest average NTG is encountered in units H27U to H15U with the exception of H17 (Table 4-5). There is a wide range in NTG from wells for each unit. The overall average NTG for any unit is very similar to the base NTG from Petrel except in H30U and H15U. The high and low NTG values from these units indicate that a narrower range has been implemented in Petrel than is observed at the wells. Some of the minimum and maximum values at a given well are outlayers compared to the rest of the wells so these were considered to be outside the likely fieldwide range. In some cases (e.g. Unit H30U) the narrow modelled range was adjusted to incorporate the evidence from the wells.

PETREL MODEL				Petrel Base v Wells ave			NTG	NTG	NTG	
Low NTG	Base NTG	High NTG	Zones	NTG	Zones	low	Well Min	All Wells	Well Max	high
0.43	0.45	0.45	H30U	0.11	H30U	0.20	0.12	0.33	0.49	0.45
0.05	0.06	0.07	H30L	0.02	H30L	0.05	0.00	0.04	0.10	0.08
0.49	0.63	0.69	H27U	0.04	H27U	0.50	0.29	0.58	0.74	0.70
0.50	0.58	0.66	H27L	0.00	H27L	0.60	0.04	0.58	0.83	0.75
0.63	0.68	0.72	H25	-0.01	H25	0.55	0.50	0.69	0.80	0.75
0.22	0.23	0.28	H17	0.05	H17	0.10	0.00	0.18	0.42	0.30
0.44	0.54	0.64	H15U	-0.16	H15U	0.55	0.50	0.71	0.94	0.85
0.16	0.24	0.29	H15L	-0.03	H15L	0.10	0.06	0.27	0.47	0.35

Table 4-5 Comparison of NTG from wells to Petrel model

Porosity

Average porosity in all reservoir sands is generally around 26% to 29% with some variation but always over 16%. The porosity in the model is very close to the average porosity from the wells and is accepted.

Water Saturation

Water saturation from logs was reproducible and consistent with the interpretation from the client data. Saturation height functions (SHF) were also derived and calculated and the modelled Sw was based on these functions. Sw from the SHF is consistently more optimistic than the Sw from logs and this would have an impact on volumes from the model.

Zones	Segments/Regions	Low So (oil leg only)	Base So (oil leg only)	High So (oil leg only)	Sh Diff (well to base model)	Sh Logs (Hc leg only)	Well	Zone Name	Net TVD/TVT	Av Phi	Av Sw Oil Leg Only
H30U	Jobi-2	0.61	0.64	0.66	-0.01	0.65	JOBI-2A	H30U	3.70	0.253	0.35
H30U	Jobi-4	0.64	0.66	0.67	0.10	0.56	JOBI-4	H30U	8.23	0.23	0.439
H30U	Jobi-1 & 5	0.58	0.63	0.64	0.08	0.54	JOBI-1	H30U	6.86	0.274	
							JOBI-5A	H30U	8.26	0.227	0.454
H30U	Jobi-3 & 6	0.64	0.69	0.71	0.16	0.53	JOBI-3	H30U	4.65	0.238	0.47
H30U	Rii-1	0.58	0.58	0.61	0.13	0.45	RII-1	H30U	1.68	0.224	0.554
H30L	Jobi-2	0.58	0.59	0.61	0.59	0.00	JOBI-2A	H30L	1.30	0.182	1.00
H30L	Jobi-4	0.62	0.64	0.62	0.02	0.63	JOBI-4	H30L	1.83	0.248	0.374
H30L	Jobi-1 & 5	0.55	0.69	0.69			JOBI-1	H30L	0.00	---	---
							JOBI-5A	H30L	0.00	---	---
H30L	Jobi-3 & 6	0.14	0.42	0.47	#VALUE!	#VALUE!	JOBI-3	H30L	0.52	0.172	---
H30L	Rii-1	0.15	0.58	0.57	#VALUE!	#VALUE!	RII-1	H30L	0.00	---	---
H27U	Jobi-2	0.76	0.79	0.80	0.27	0.52	JOBI-2A	H27U	7.99	0.301	0.48
H27U	Jobi-4	0.76	0.79	0.80	0.16	0.63	JOBI-4	H27U	16.46	0.3	0.372
H27U	Jobi-1 & 5	0.79	0.81	0.82	0.20	0.61	JOBI-1	H27U	8.46	0.27	---
							JOBI-5A	H27U	11.95	0.292	0.327
H27U	Jobi-3 & 6	0.82	0.83	0.84	0.08	0.75	JOBI-3	H27U	10.56	0.298	0.252
H27U	Rii-1	0.80	0.82	0.82	0.14	0.67	RII-1	H27U	10.81	0.302	0.328
H27L	Jobi-2	0.79	0.80	0.81	0.79	0.02	JOBI-2A	H27L	11.49	0.284	0.99
H27L	Jobi-4	0.80	0.81	0.81	0.16	0.65	JOBI-4	H27L	12.36	0.301	0.35
H27L	Jobi-1 & 5	0.84	0.84	0.85	0.18	0.66	JOBI-1	H27L	9.37	0.29	0.256
							JOBI-5A	H27L	13.95	0.285	0.391
H27L	Jobi-3 & 6	0.81	0.82	0.83	0.44	0.38	JOBI-3	H27L	0.53	0.183	0.62
H27L	Rii-1	0.80	0.81	0.83	0.14	0.67	RII-1	H27L	12.35	0.316	0.332
H25	Jobi-2	0.76	0.79	0.79	-0.21	1.00	JOBI-2A	H25	9.60	0.277	
H25	Jobi-4	0.79	0.80	0.81	0.30	0.50	JOBI-4	H25	12.78	0.266	0.5
H25	Jobi-1 & 5	0.82	0.83	0.84		0.65	JOBI-1	H25	13.41	0.268	0.353
							JOBI-5A	H25	11.86	0.289	---
H25	Jobi-3 & 6	0.82	0.83	0.84	0.19	0.65	JOBI-3	H25	19.92	0.275	0.355
H25	Rii-1	0.80	0.81	0.82	0.21	0.61	RII-1	H25	21.94	0.284	0.392
H17	Jobi-2	0.34	0.52	0.62	0.50	0.03	JOBI-2A	H17	1.37	0.259	0.98
H17	Jobi-4	0.61	0.73	0.75	#VALUE!	#VALUE!	JOBI-4	H17	0.35	0.162	---
H17	Jobi-1 & 5	0.73	0.74	0.75			JOBI-1	H17	0.00	---	---
							JOBI-5A	H17	2.59	0.233	---
H17	Jobi-3 & 6	0.76	0.76	0.77	0.05	0.71	JOBI-3	H17	4.76	0.287	0.292
H17	Rii-1	0.71	0.71	0.73	#VALUE!	#VALUE!	RII-1	H17	6.24	0.316	---

Table 4-6 Sw from logs compared with modelled Sw

The SHFs as described in the PRR were run and the results do give low average Sw compared to Sw from logs. The Results at given points were presented in the PRR compared to Sw from logs and they look reasonable in the clean sands given that the logs so not have the resolution of the core it is usual for the results of the algorithm to meander around the sample points but it did not explain the overall optimistic view from the model compared to logs (Table 4-6).

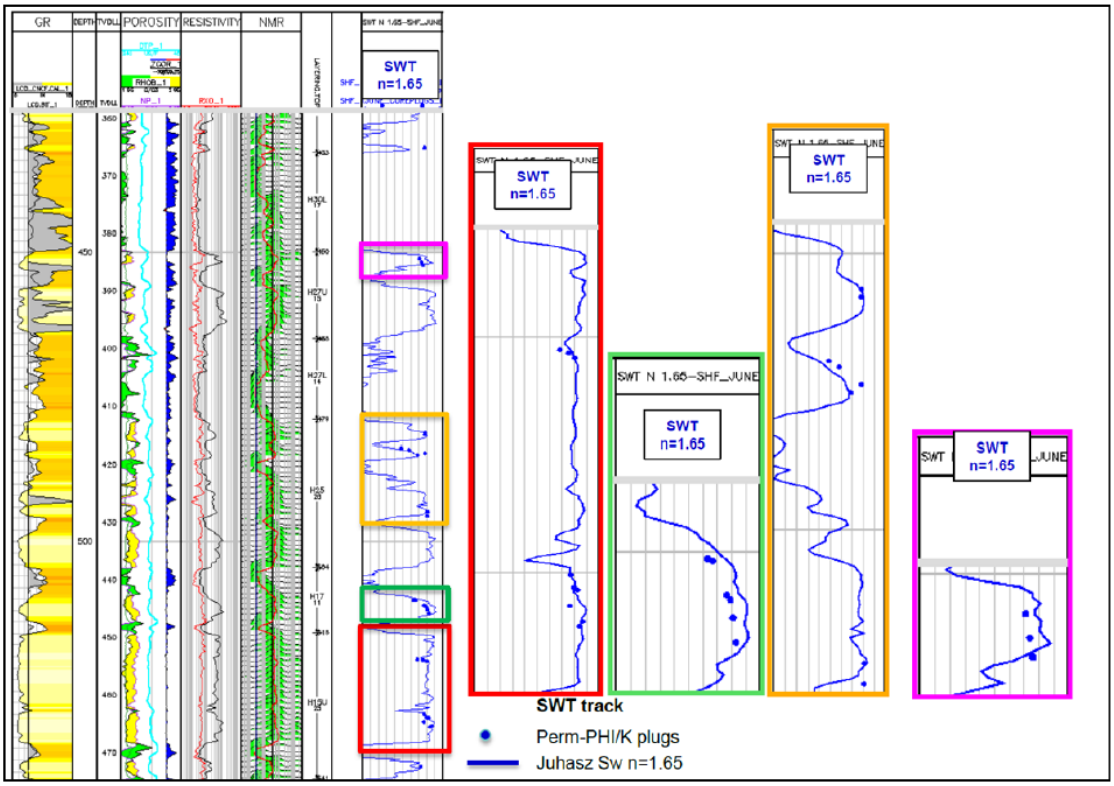


Figure 2-67: Jobi-3 Water Saturation calculation and comparison with SHF

Figure 4-7 From PRR: Sw from core-driven SHF (blue points) compared to Sw from logs in Jobi-3

The SHF results are calculated using Sw=A*Kg^B

Where Kg is permeability in mD and A and B are “coefficients calculated as a function of surface or interfacial tension” (Figure 4-8).

- **A H27** = - 0.3823712 *(log10(0.000698*HAFWL) ^5 - 1.637449 (log10(0.000698*HAFWL) ^4 - 1.788438 *(log10(0.000698*HAFWL) ^3 + 0.1481912 *(log10(0.000698*HAFWL) ^2 + 0.9870985 *log10(0.000698*HAFWL) + 3.92307
- **B H27** = + 0.01064684 * (log10(0.000698*HAFWL) ^5 + 0.02954752 * (log10(0.000698*HAFWL) ^4 - 0.01604066 *(log10(0.000698*HAFWL) ^3 - 0.06103914 * *(log10(0.000698*HAFWL) ^2 - 0.03236305 *log10(0.000698*HAFWL) - 0.380805

Figure 4-8 From PRR: A and B SHF coefficients for H27

For the permeability input to the functions the reservoir is divided into six permeability classes and the mid-point permeability input as the permeability for the relevant rock type (Figure 4-9).

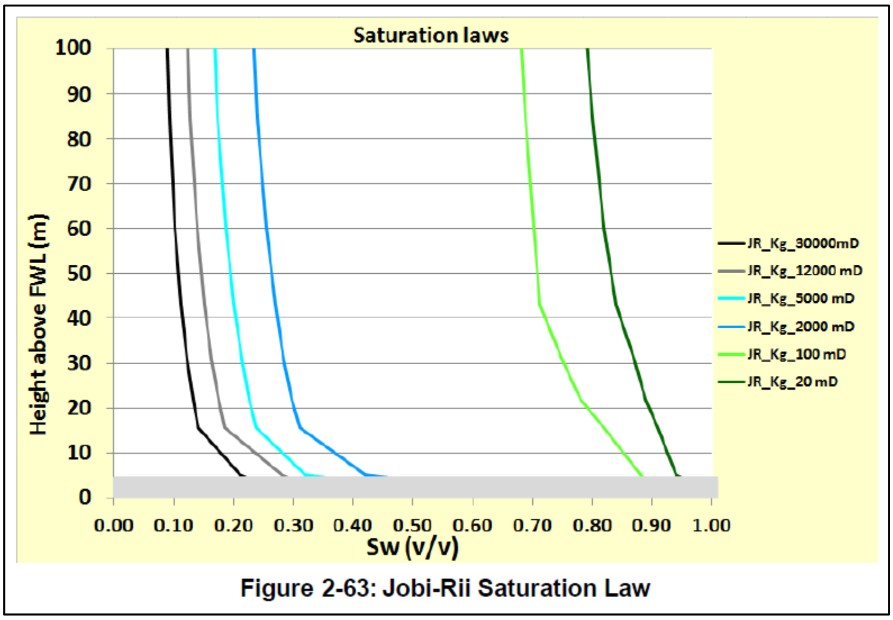


Figure 2-63: Jobi-Rii Saturation Law

Figure 4-9 From PRR: Saturation functions with rock type mid-point permeability input

The regional capillary pressure data has been used as the input for the permeability classes (Figure 4-10). However there appears to be a gap in the data represented by the six classes in this SHF work. The three classes adopted and presented in Figure 4-9 put all of the mid-range permeabilities (300 to 3000mD) into the 2000mD type. This leaves a gap in the range of functions and excludes a lot of the intermediate trends illustrated in the green to orange trends in Figure 4-10. This would contribute to the optimistic Sw in the model.

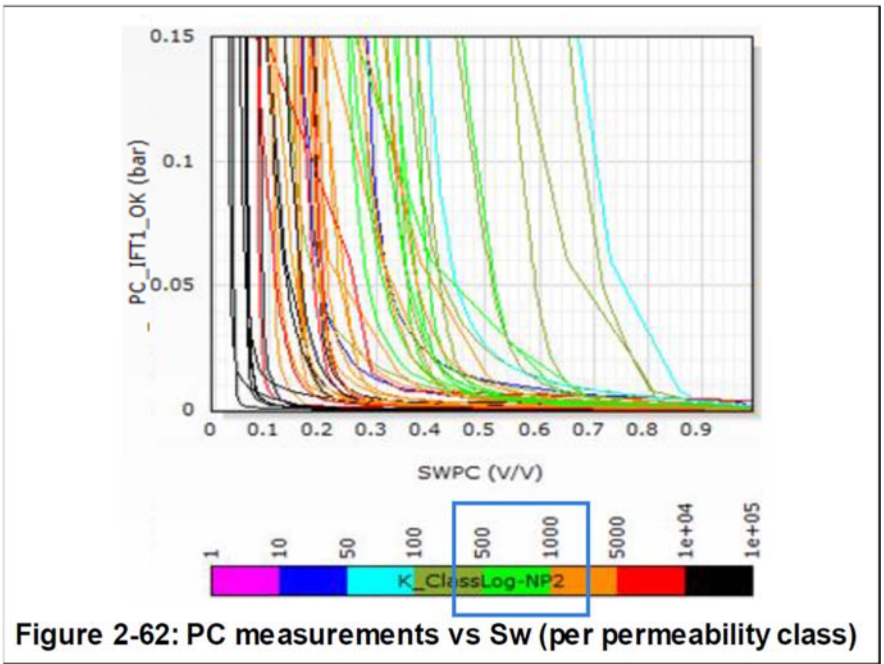


Figure 2-62: PC measurements vs Sw (per permeability class)

Figure 4-10 From PRR: Addition of capillary pressure measurements from other Ugandan fields

Another factor will be the calculated permeability which provides the input for the functions (Figure 4-11). The left hand plot shows the modelled poro/perm trends by facies. The porosity (horizontal) scale is 0.03 to 0.42 in the modelled properties (left hand) plot and 0.15 to 0.45 in the core plot. The black lines highlight where porosity=0.2 and permeability=1000mD on each plot. The most optimistic point for a 20% porosity sample from core corresponds with the mid values in the modelled properties. The trend for the best quality reservoir is in the same area as the samples from core but the range of permeability included is narrower than the spread of measurements at any given porosity value. Even considering that the core data is presenting total porosity, the effective porosity will be the same value in the cleanest formation.

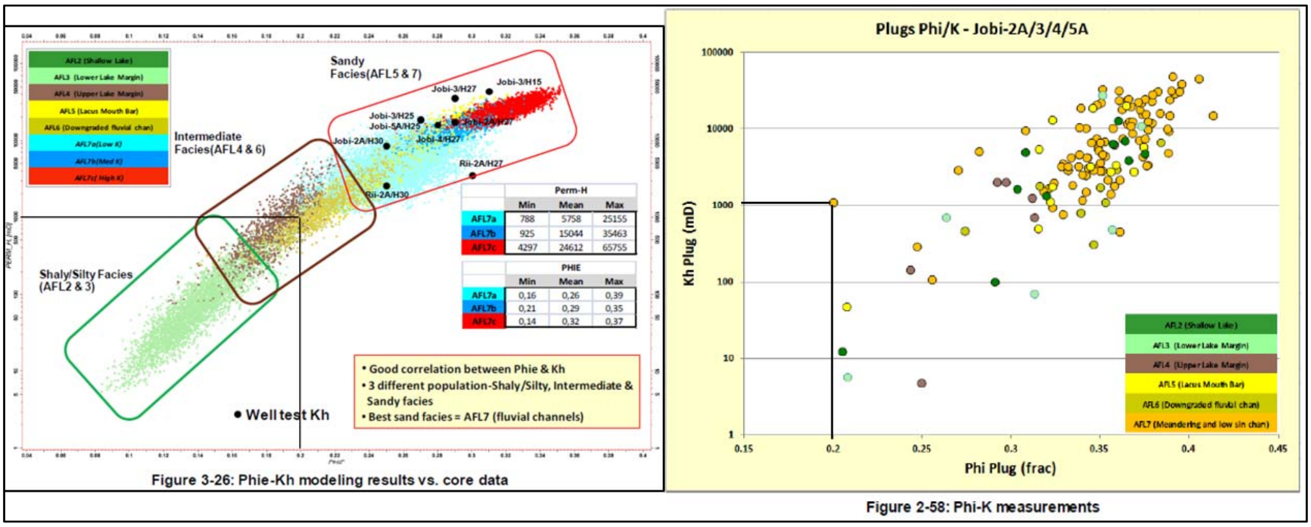


Figure 4-11 Modelled poro/perm compared to poro/perm data from core

It appears then that the permeability input and the permeability classes used to apply the SHFs described combine to give higher oil saturations than those calculated from logs. There is some uncertainty around these high porosity and permeability rocks exacerbated by a fresh formation water so Sw from logs could possibly be too pessimistic. The results from both log results and saturation height functions based on regional data were included in the range of Sw included in the volumes calculations.

Oil Water Contacts

As mentioned in section4.2.2.1, the layering and faulting of the field gives a complex fluid contact situation. Different contacts are observed to vary within Jobi-Rii with different contacts for each reservoir unit. The fluids as calculated from logs are represented in Figure 4-12 where gas is encountered in the Jobi-1 which sits highest on the structure. All other wells encounter the reservoir deeper than the gas-oil-contact in Jobi-1. Water is observed in Jobi-2A shallower than oil in other wells confirming the varying OWC across the field.

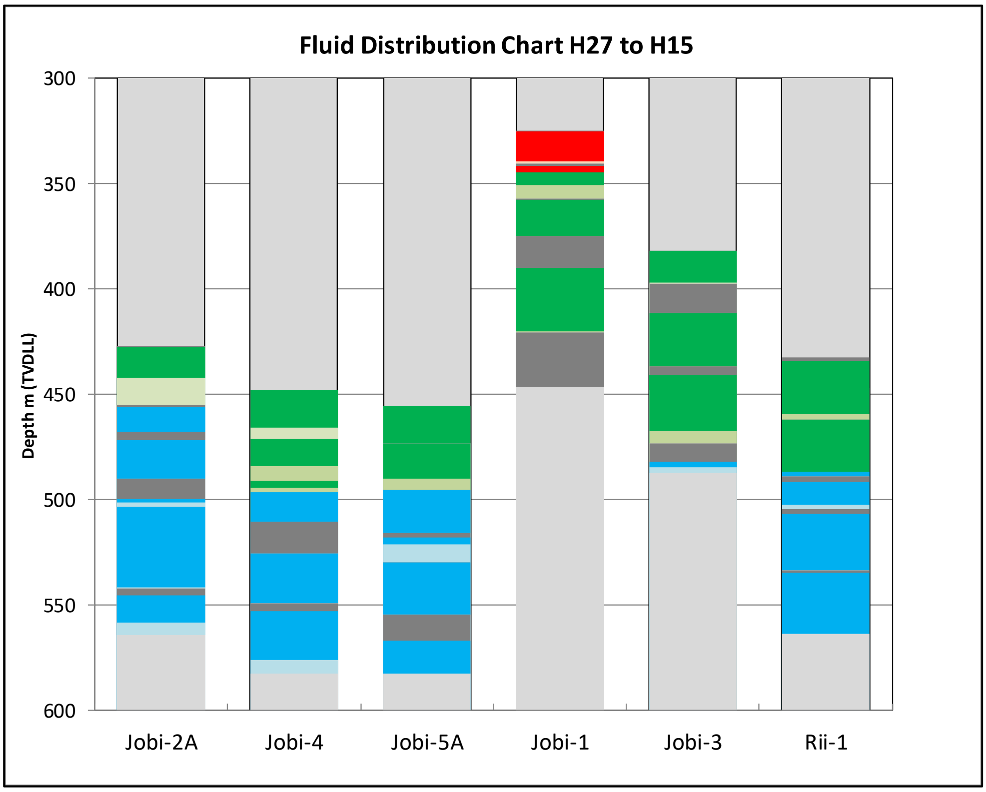


Figure 4-12 Jobi-Rii fluids for H27 to H15

Some pressure data is also available and this was used where reliable to define the free water level. A combined water gradient was applied in areas where no water pressure gradient was obtained. Where pressure data is limited the water-up-to and oil-down-to (WUT and ODT) from logs are taken as the minimum and maximum. The contacts ranges are defined using a combination of all the available data.

4.2.2.3 In place volumes

TRACS methodology

TRACS carried out an extensive analysis of depth uncertainty on Jobi-Rii and used the insights gained from this process to help quantify the GRV uncertainty on other Tilenga fields. Similarly, following a review of average properties, a consistent methodology was defined and extended to the rest of Tilenga Phase 1.

GRV

TRACS carried out a depth uncertainty analysis related to inform the GRV uncertainty. Three aspects were considered:

1. seismic pick
2. depth conversion
3. well tie

The seismic interpretation for Jobi-Rii was provided as a series of time surfaces, not the original horizon interpretation. The surfaces are highly smoothed relative to the underlying seismic data. TRACS generated an independent H30 horizon with which to assess depth uncertainty for the Tilenga fields.

The Tilenga fields have a number of depth conversions applied (detailed in the PRRs). The approaches are based on a layered Vo-Kz, with either 2 or 3 layers, depending on the field. The Vo and k values change between fields. Note also datum changes – these have been accounted for in the various methods.

V0 data are provided in the individual PRR documents[1]. The data allow a series of lines of ‘best fit’ to be explored to recreate the PRR method(s). The PRR Best Fit for Jobi-Rii can be recreated with a second order polynomial ONLY if the Vo intercept is set to 2158m/s, see Figure 4-13.

[1] The data were not provided in raw format so were digitised. The quality of the digitisation is sufficient for the sensitivity analysis carried out here.

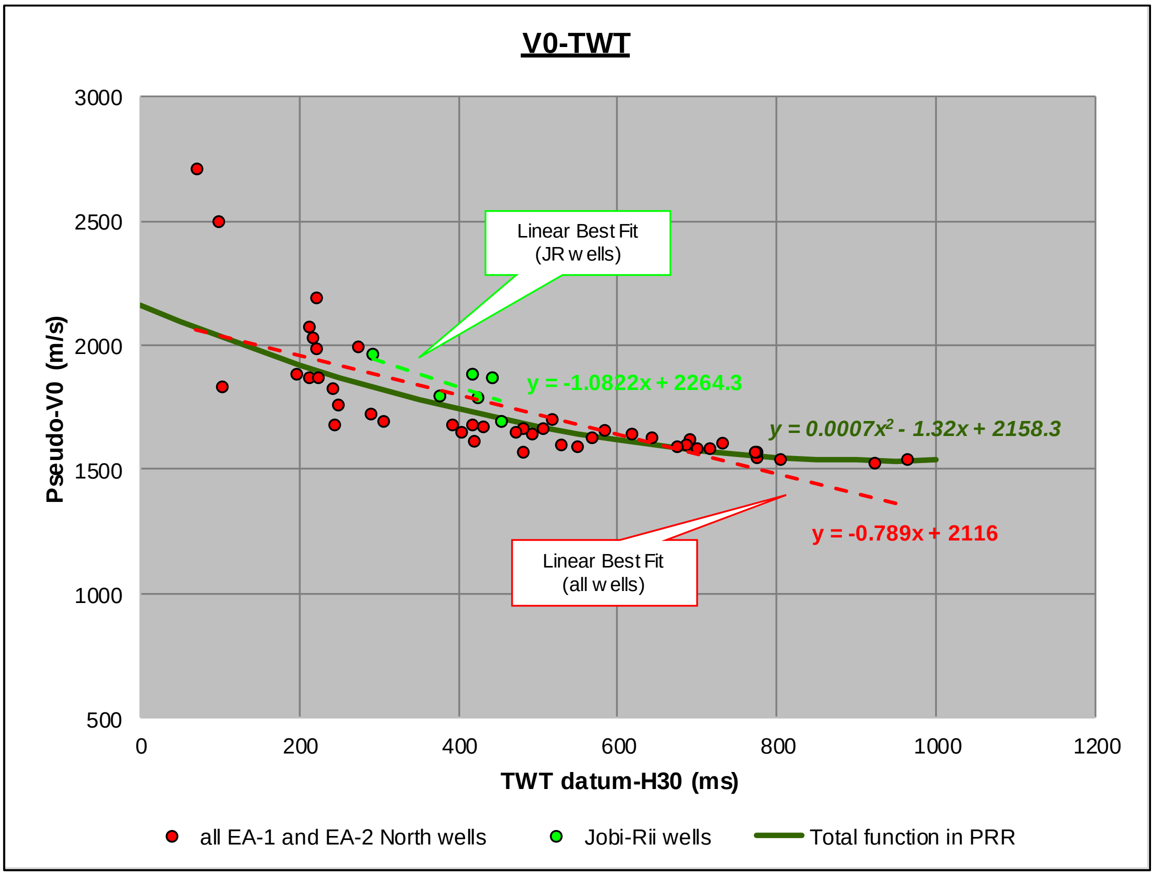


Figure 4-13 V0-Time data with best fit lines

Two alterative depth conversion calculations for H30 have been generated using the best fit lines obtained from the TRACS analysis. The two functions are given below and compared in Figure 4-14. Note RMS error is reference to PRR depth conversion.

- MK1 depcon: Z = 0.7319 * TWT + 71.911 (Focussed on Jobi-Rii wells only; RMS error 6.2m)
- MK2 depcon: Z = 0.718 * TWT + 54.03 (All EA-1 and EA-2 North wells in PRR chart; RMS error 27.6m)

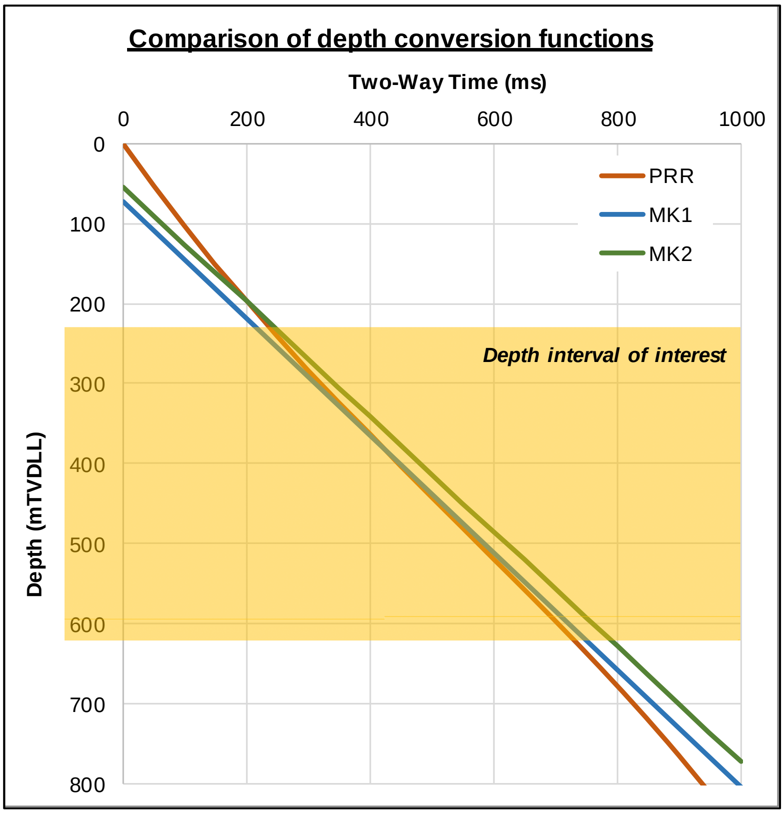


Figure 4-14 Jobi-Rii: comparison of alternative depth conversion approaches

The Jobi-Rii wells are generally located in crestal positions; down dip areas are less well constrained. The current well ties use an ellipse of 2 x 5 km orientated 015°. TRACS tested alternative well tie methods: convergent gridding with an infinite radius of influence, Radius 2000m, Radius 5000m (Figure 4-15andFigure 4-16).

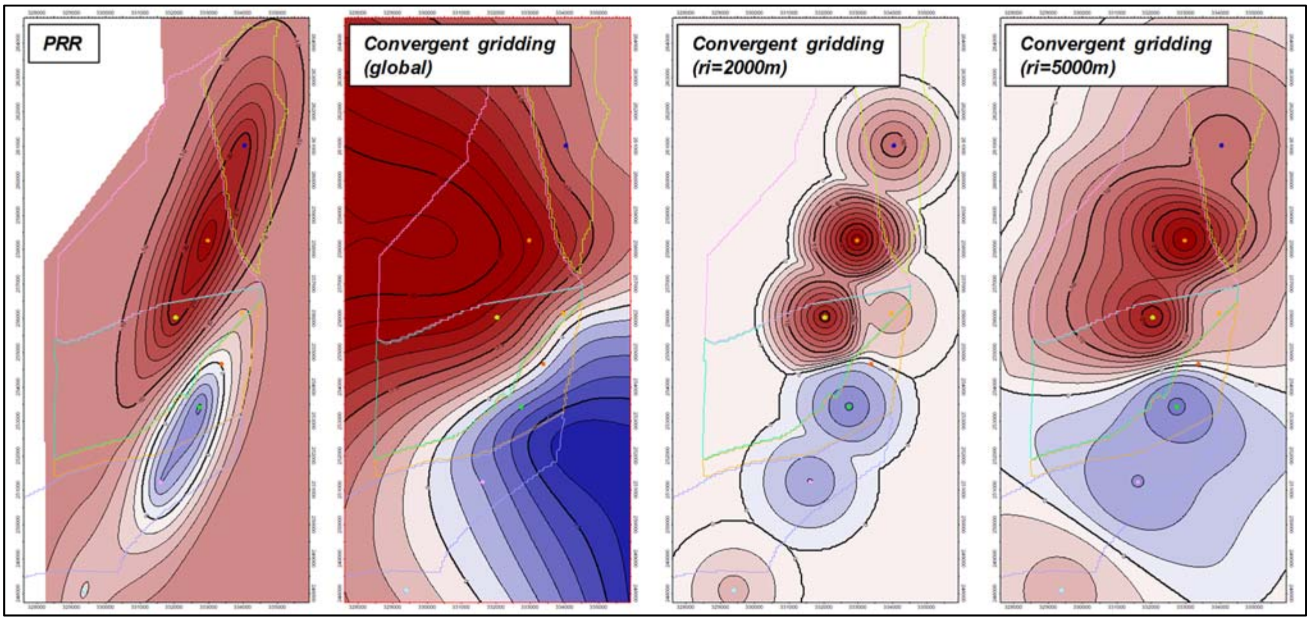


Figure 4-15 Jobi-Rii: comparison of alternative well tie methods

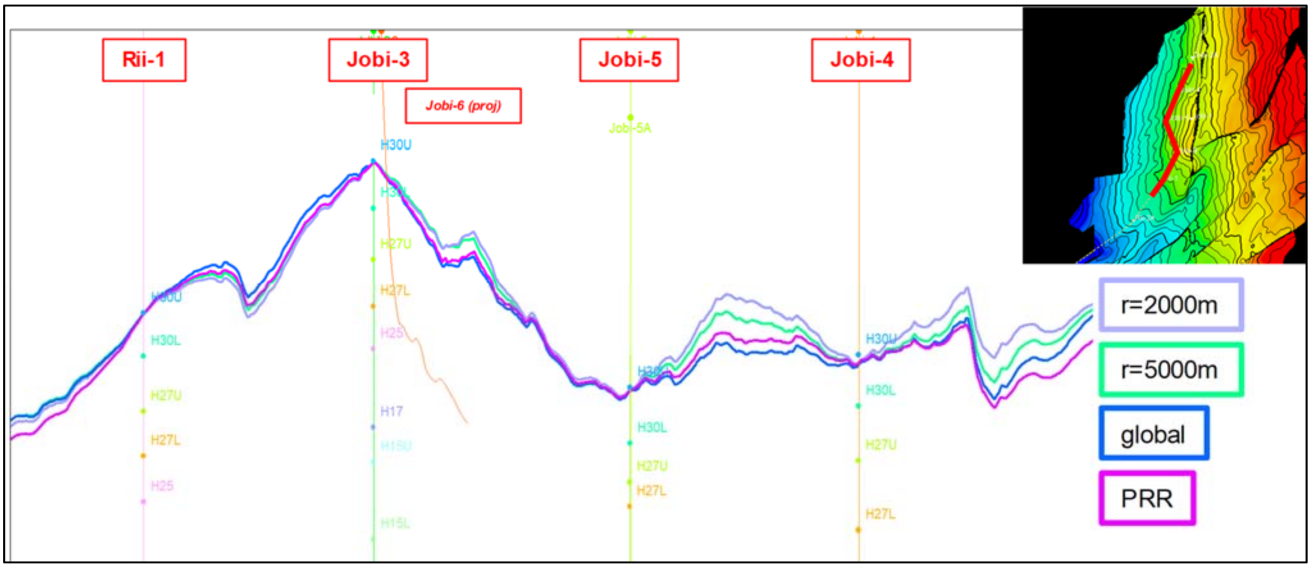


Figure 4-16 Jobi-Rii: comparison of alternative well tie methods (cross section)

The impact of depth uncertainty for Jobi-Rii is assessed using the inputs described above compared to the reference surface (H30 surface from model), see Figure 4-17. The impact of depth uncertainty for Jobi-Rii is defined as ±10% relative to the reference GRV.

The GRV range of ±10% related to depth uncertainty has been carried through to the other Tilenga fields.

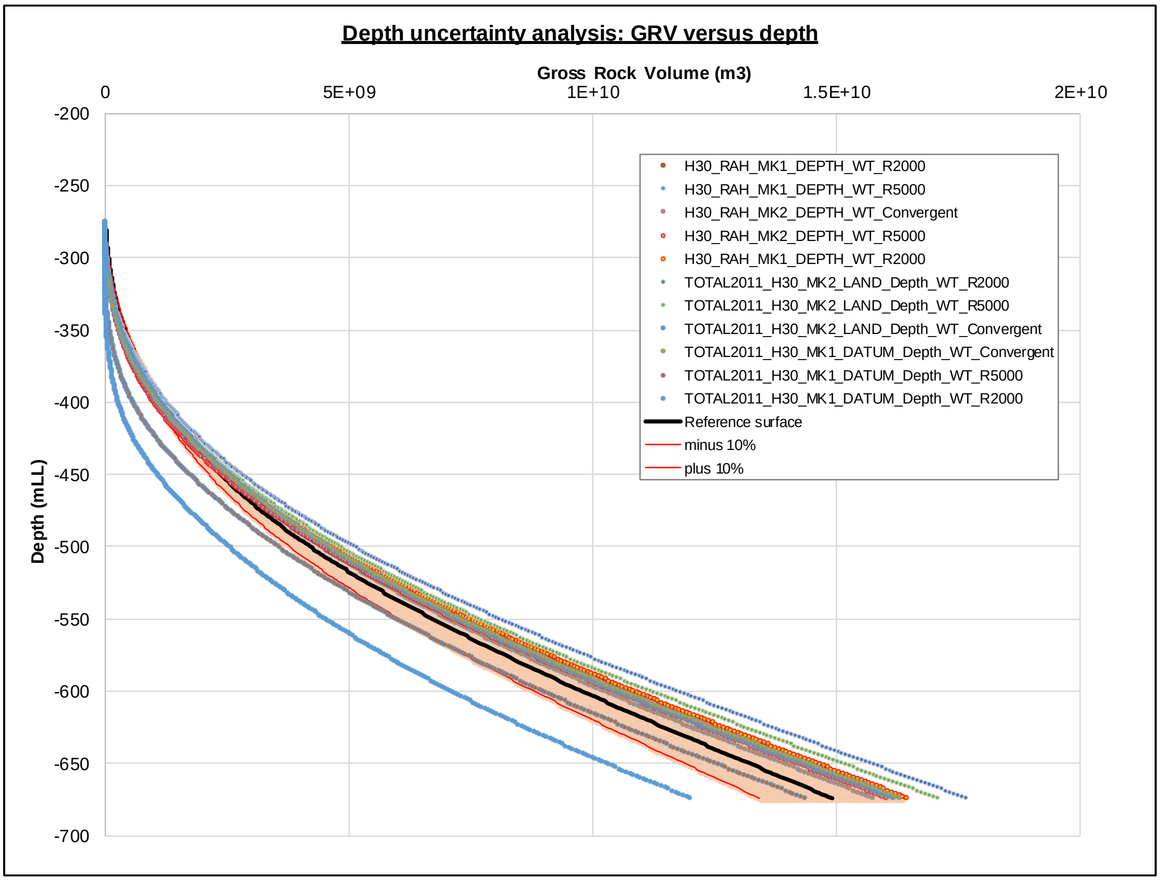


Figure 4-17 Jobi-Rii: impact of depth uncertainty on GRV

Contacts

The fluid distribution was reviewed for each pool in order to define ranges of fluid contacts. There is a good pressure data set for Jobi Rii. In reservoirs with reliable pressure data these were used to define the Mid case contacts; the uncertainty range is then derived by using different pressure gradient interpretations and/or fluid densities. In reservoirs with no reliable pressure data, ODT and WUT depths were used to define minimum and maximum cases and the average depth was used to define the Mid case. The results for the mid case oil contacts are summarised in Table 4-7.

TRACS implemented some contact changes but most have no material impact on GRV. However, in the H30 reservoirs the revised Mid contacts are shallower than those carried by Tullow leading to a material reduction in the range of GRVs.

Depths in mSL	**J2**	**J1 / 4 / 5**	**J3 / Rii1**
H30	412	443	414
H27	443	485	485
H25 / H17 / H15	443	485	485

Table 4-7 Jobi-Rii: Mid case oil contact

Table 4-7 shows that the Phase 1 reservoirs (H27/H25/H15) have a common contact in the main area of Jobi Rii with the J2 area being a separate accumulation.

Jobi Rii has identified relatively small gas caps in some reservoirs. The Tullow gas oil contacts were accepted and used to estimate free gas volumes.

The fluid contacts were applied to the static models to generate updated Low, Mid and High GRV values for use in the TRACS @Risk model. A +/- 10% range was applied to the Low and High GRV cases to account for uncertainty relating to structural interpretation and depth conversion.

Properties

The net-to-gross in the models is varied between Low, Mid and High cases by adjusting the proportions of the best reservoir facies. Total's facies and property modelling workflows are generally supported as an appropriate method of populating the static models and deriving in place volumes. As mentioned previously, there are some concerns around the weighting of influence, i.e. the seismic attributes appear to have significantly more influence than the wells.

There is likely to be a lot of detail beyond seismic resolution that could throw up surprises relating to facies and NTG distribution, lateral compartmentalisation within a segment and possibly vertical compartmentalisation. For instance, the seismic signal may be dominated by a particular facies or bed. While the geometries observed are compelling, they may not be wholly representative. Note that this is not a criticism of the Operator's technique or workflow, but a general caveat about the use of seismic attributes in modelling.

The two key messages are that (1) well averages of NTG might not be indicative of 3D NTG averages and (2) seismic attributes may not be representative of 3D properties.

On comparison of properties from well averages and model averages for reservoir layers there were observed to be some significant differences, especially in saturations. Porosities were generally found to be consistent.

TRACS recognises that using log derived properties (i.e. NTG, porosity, saturation) and model derived averages (which uses wells as input to populate the depositional/facies model) should guide the selection of the property ranges for use in STOIIP and GIIP calculations. TRACS has used the average value from the mid case static model and well analysis to represent the mid-point for the NTG, porosity and saturation ranges. The minimum and maximum values for properties are selected based on the ranges from the well data and from the low and high static models.

The NTG and porosity ranges are taken to be identical for the oil and gas legs in the field. However, the free gas saturation is taken to be 5% higher than the oil saturations given their position in the hydrocarbon column.

The oil formation volume factor is taken to be a constant 1.046 and the gas expansion factor is taken to be a constant 37.7 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Jobi Rii field are presented in Table 4-8. The STOIIP has been split between the Phase 1 reservoirs, H30U reservoir and H17/H15L reservoirs. The GIIP is presented as solution gas and gas cap (free) gas for all reservoirs. An average gas oil ratio of 109 scf/bbl has been used to estimate the solution gas volumes.

In-Place volumes	**Reservoir / areas**	**P10**	**P50**	**P90**
STOIIP (MMbbls)	Phase 1: H27/H25/H15U	839.2	1102.9	1392.5
	Job-Rii H30U	101.0	155.0	225.2
	Job-Rii H17/H15L	49.7	99.0	161.6
	Total STOIIP	**989.9**	**1357.0**	**1779.3**
GIIP (Bscf)	Solution gas	107.9	147.9	193.9
	Gas cap gas	20.7	29.3	38.7
	Total Gas	**128.6**	**177.3**	**232.7**

Table 4-8 TRACS estimate of Jobi-Rii STOIIP and GIIP

4.2.2.4 Analytical approach to CR assessment

The analytical approach for estimating recovery factor and generating profiles was similar for all Phase 1 fields. An overview of the process and the results for Jobi Rii is outlined below.

Phase 1 waterflood project : Core Area and North

The Jobi-Rii full field dynamic simulation model with water injection development was reviewed to generate an understanding of the recovery mechanism for the pattern flood. It was noted that recovery varied significantly across the field and is strongly affected by the development pattern as well as the geology. This is demonstrated in Figure 4-18.

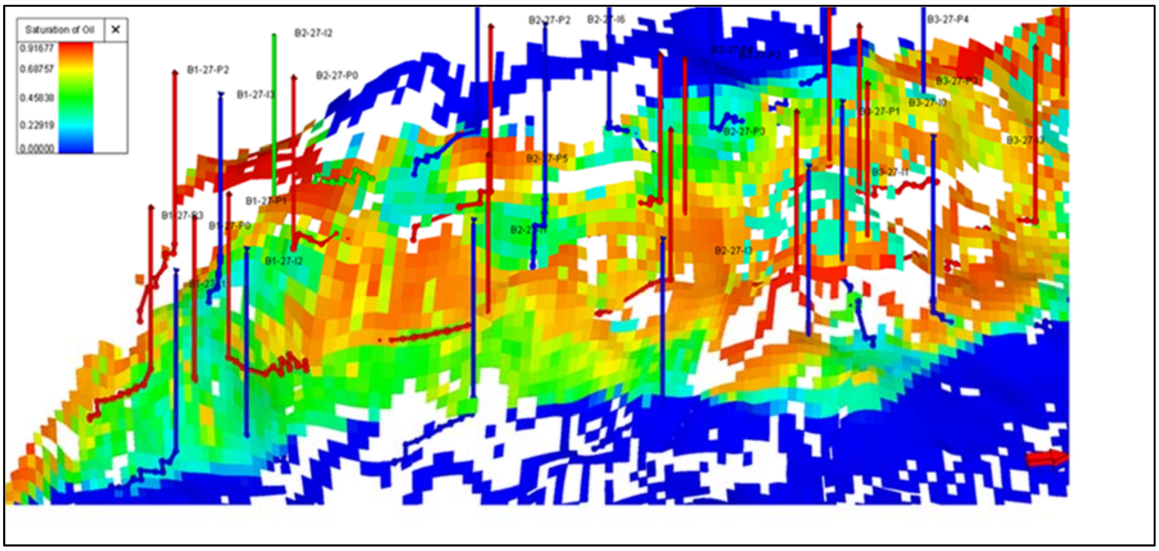


Figure 4-18 Example of oil saturation after 25 years showing variable recovery

This observation was investigated by plotting the recovery factor in each simulation model cell versus cumulative STOIIP (Figure 4-19). This showed complex behaviour and means that recovery factors cannot be easily estimated analytically using a combination of microscopic and macroscopic sweep – numerical modelling is necessary. After a review of the Mid case simulation model for Jobi-Rii it was concluded that the model was acceptable for estimating the micro and macroscopic sweep and it was used as the basis for the Mid case recovery factors for 25 and 50 year field life.

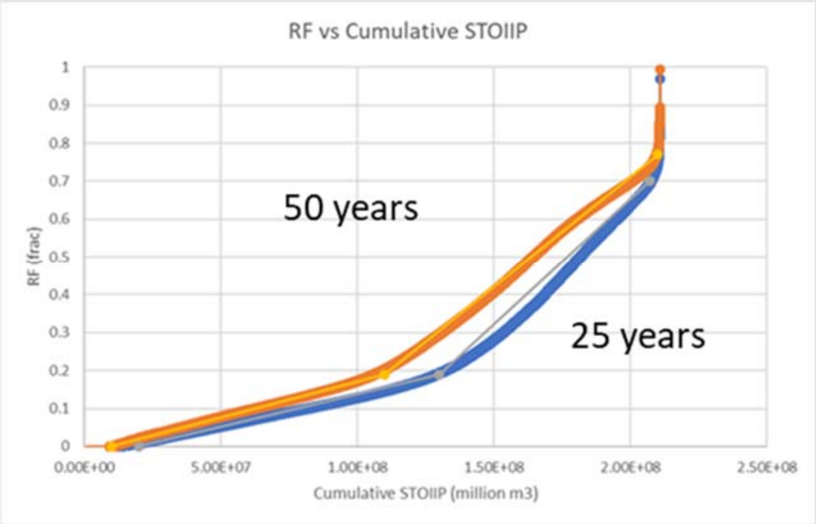


Figure 4-19 Recovery factor vs cumulative STOIIP in simulation model cells showing complex sweep

Low and High case simulation models were provided by Tullow and had a range of recovery factors, although it was noted that these did not include the uncertainty in relative permeabilities and Sor, the most significant dynamic uncertainties. However, these were cross checked with fractional flow analysis to ensure consistency and accepted as reasonable.

The resulting range of recovery factors for the Jobi Rii Phase 1 oil development is presented in Table 4-9 for 25 and 50 years.

Field	Project		TRACS	
			25 yrs	50 yrs
Jobi Rii	WF Core area (Main & North)	L	0.14	0.17
		M	0.20	0.25
		H	0.25	0.29

Table 4-9 Jobi-Rii Phase 1 Oil Recovery Factors

The range of recovery factors were used together with the output from the simulation model to generate input to a type curve tool that was used to generate a Phase 1 (hub) forecast honouring the key constraints of the development. The type curve tool is a recognised spreadsheet method for aggregating projects under a common set of constraints. The output from a simulation model can be used to construct a type curve in the form of deliverability vs recovery factor which is used as input to the type curve forecasting tool.

The type curves generated from the respective simulation models were scaled to honour the 25 year and 50 year recovery factors presented in Table 4-9.

The Jobi Rii simulation models were provided with the Phase 1 development wells input into the model. Cross checking with the number of wells in the model against the well count presented in the latest Basis of Design (BOD) there were some slight differences in well numbers. However, within the uncertainty of the development and given the significant well numbers required for development it was concluded that the output from the simulation models gave a good estimate of the production forecast associated with the Phase 1 development.

The simulation models without the Central Processing Facility (CPF) constraints were re-run with 50 years of production forecast. The simulation results were used to generate the type curves of fluid rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles (together with other Phase 1 fields) with the CPF constraints.

The oil production wells are constrained by a maximum liquid rate of 10 Mblpd, a minimum BHP of 10 bars and a maximum water cut of 98%. The production wells are also controlled by the ESP operating gas/liquid ratio range, from 35% to 45%.

The maximum water injection rate of a water injectors is 10 Mbwpd. The maximum injection pressure of injection wells varies from 42 to 62 bars, based on the depth of injection intervals. The water injection rate is also controlled by 100% reservoir voidage replacement. These constraints on water injection wells are required to keep the cap rock integrity.

Furthermore, the maximum oil rate of Jobi-Rii field is set at 70 Mbopd.

The field operating efficiency is 93% and the well operating efficiency is 95%.

The oil production profiles were generated from the type curve tool, combining all Phase 1 fields to meet the constraints of the CPF and pipeline capacity. The resulting range of profiles for Jobi Rii are presented in Figure 4-20.

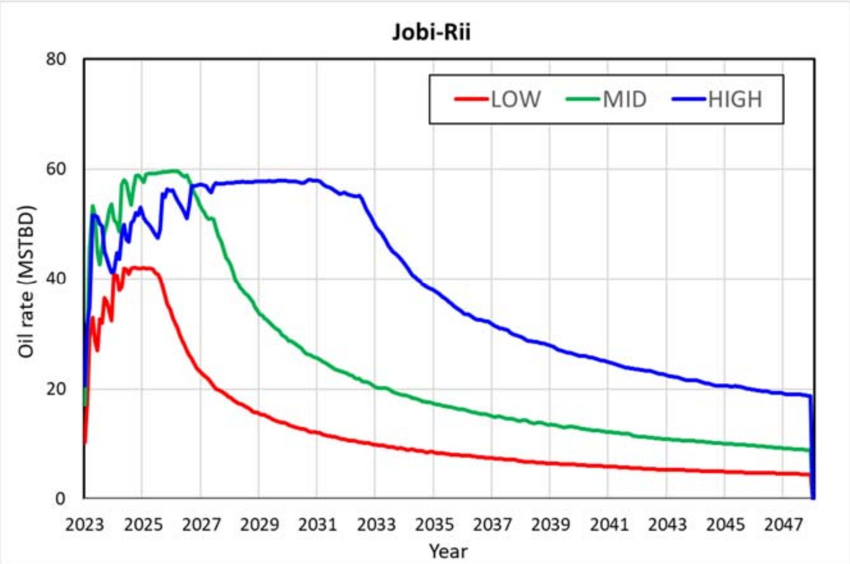


Figure 4-20 Oil production forecasts – Jobi-Rii Field

Polymer flood

The Ugandan fields have been identified as potentially benefiting from a polymer flood to increase oil recovery. TRACS have reviewed the incremental recovery associated with a polymer flood for the Phase 1 fields.

The 25 year Mid case recovery factor for the Jobi-Rii polymer was based on the Job Rii polymer flood model provided by Tullow. Mid and High case estimates were based on fractional flow analysis using uncertainties reported in the PRR. The 50 year recovery factors were based on fractional flow analysis with double the pore volume injected. TRACS have only considered the Phase 1 reservoirs (H27/H25/H15U) for polymer flood for Job Rii.

Figure 4-21shows the significantly improved recovery in areas of moderate sweep from conventional water flood when compared to a polymer flood.

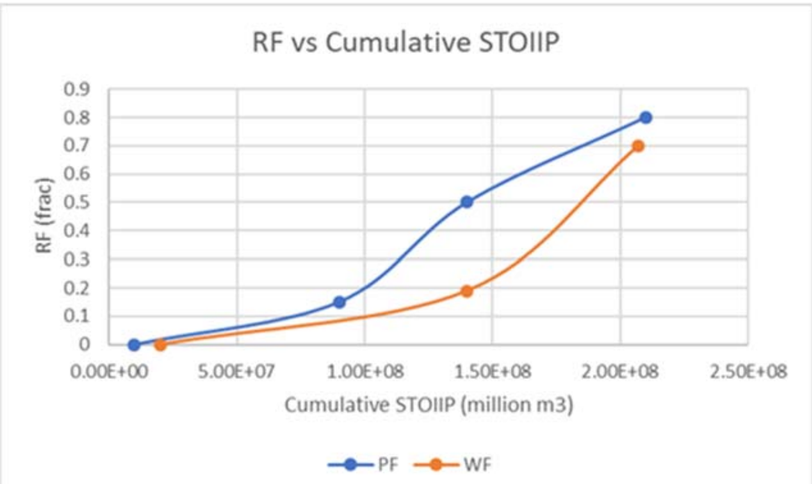


Figure 4-21 Recovery factor vs cumulative STOIIP in water flood and polymer flood simulation model cells

The range of recovery factors for a polymer flood at 25 and 50 years as estimated by TRACS is presented in Table 4-10.

Field	Project		TRACS	
			25 yrs	50 yrs
Jobi Rii	PF Core area (Main & North)	L	0.23	0.27
		M	0.30	0.36
		H	0.33	0.40

Table 4-10 Jobi-Rii Recovery Factors for Polymer Flood

No production profiles were generated for the polymer flood as a commerciality test was not required.

Remaining Jobi-Rii reservoirs (H30U and H17+H15L)

Recovery factors for the lower NTG H30U reservoir as reported in the PRR for a conventional waterflood are assumed to be the best guide for lower quality reservoir (in the absence of simulation models). A wide range of uncertainty was assumed due to uncertainty in NTG and connectivity.

It was assumed that the H17+H15L zones would have similar recovery factors to H30U. These sets of recovery factors have been used to estimate a range of recoverable volumes.

Field	Project		TRACS	
			25 yrs	50 yrs
Jobi Rii	WF H30U (Main & North)	L	0.07	0.08
		M	0.13	0.16
		H	0.20	0.25
	WF H17+H15L (Main)	L	0.07	0.08
		M	0.13	0.16
		H	0.20	0.25

Table 4-11 Jobi-Rii Oil recovery Factors for other projects

No production profiles were generated for these reservoirs as a commerciality test was not required.

Gas recovery factors

To estimation of gas recovery factors falls into two categories:

- Solution gas
- Primary gas cap gas

For the solution gas the range of recovery factors for the gas is assumed to be the same as oil (given this is a waterflood the gas solution gas should primarily stay within the oil). To obtain the sales gas recovery factor a 50% reduction is applied to the gross recovery factor to account for fuel and flare.

For the gas cap recovery factors a range of recovery factors have been used to address in uncertainty in back pressure (compression) and subsurface recovery (such as water production which could prematurely kill a well). The range of gas recovery factors are presented in Table 4-12.

	Low	Mid	High
Gas cap RF	0.50	0.65	0.80

Table 4-12 Jobi-Rii Gas recovery Factors

Note that no discount has been applied to these recovery factors as it is assume that the AG will cover the fuel and flare.

4.2.3 Estimation of Jobi Rii Contingent Resources

Jobi Rii is a key field in the development of the Albert Basin and is part of the Phase 1 development project. This Phase 1 project is well advanced from a technical point of view but there are still some key commercial challenges before this project can be sanctioned. Additional phases of development are being considered which would include development of additional Jobi Rii reservoirs as well as a polymer flood on the key reservoirs. All resources associated with Jobi Rii are classified as Contingent Resources (CR).

4.2.3.1 Contingent Resources Development Pending

The Jobi Rii Phase 1 development is categorised as CR Development Pending (DP). To estimate the DP CR the forecast has been taken to the licence expiry date.

The oil DP Contingent Resources for Jobi Rii are presented in Table 4-15. Note that there are no gas PD Contingent Resources as a gas sales solution still needs to be matured.

4.2.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs
- Waterflood development of the remaining Jobi Rii reservoirs predicted at 50 years

To generate the range of recoverable volumes the range of recovery factors presented in section 4.2.2.4 have been applied to the ranges of STOIIP presented in Table 4-8. To generate the low, mid and high recoverable volumes the low recovery factor has been combined with the low STOIIP, mid with mid and high with high, respectively. Although from a probabilistic point of view this may seem extreme it is considered to be justified given the large uncertainty associated with the Jobi Rii field.

In the case the waterflood extension for Phase 1 reservoirs the incremental recovery to the Phase 1 development resources are presented as DoH and the incremental recovery of the polymer flood compared to the waterflood development is also classified as DoH. The overview of DoH oil resources by project is presented in **Table 4-13**.

CR DoH Oil	Gross (MMbbls)		
	1C	2C	3C
Phase 1 WF extension	26.9	58.4	62.6
WF Additional Reservoirs	12.4	41.3	96.7
Polymer Flood	83.9	121.3	147.6
Total all oil DoH	**123.2**	**221.0**	**306.9**

Table 4-13 Jobi Rii Oil DoH Contingent Resource summary

Gas

The solution gas is a by-product of the oil development and has value if a gas development solution is matured. The solution gas recovery associated with the Phase 1 oil project as well as the oil projects presented in **Table 4-13** have been classified as DoH. The recovery factors presented in section 4.2.2.4 (taken to be the same for solution gas recovery as for oil) have been combined with the solution GIIP presented in Table 4-8 in the same way as the oil (low with low, etc.). The overview of DoH gas resources by project is presented in Table 4-14.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	6.3	11.9	18.6
Phase 1 WF extension	1.5	3.2	3.4
WF Additional Reservoirs	0.7	2.2	5.3
Polymer Flood	4.6	6.6	8.0
Total all gas DoH	**13.0**	**23.9**	**35.3**

Table 4-14 Jobi Rii Gas DoH Contingent Resource summary

4.2.3.3 Contingent Resources Development not Viable

There are no oil resources classified as Development not viable (DnV). However, the development of the gas caps in Jobi Rii are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested. The gas DnV Contingent Resources for Jobi Rii are presented in Table 4-16.

4.2.4 Jobi Rii CR summary

The total Contingent Resources for the Jobi Rii field are presented in Table 4-15 for oil resources and Table 4-16 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	115.4	217.7	341.2	32.7	61.7	96.7
Development on Hold	123.2	221.0	306.9	34.9	62.6	87.0
Total All CR Categories	**238.6**	**438.7**	**648.1**	**67.6**	**124.3**	**183.6**

Table 4-15 Jobi Rii Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	13.0	23.9	35.3	3.7	6.8	10.0
Development currently not viable	10.4	19.1	31.0	2.9	5.4	8.8
Total All CR Categories	**23.4**	**43.0**	**66.3**	**6.6**	**12.2**	**18.8**

Table 4-16 Jobi Rii Gas Contingent Resource summary

4.3 GUNYA FIELD

4.3.1 FIELD BACKGROUND / INTRODUCTION

Field Name	Gunya
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field consists of six fault-bound panels in a structural trap (dip and fault closure). Only four of the panels is considered to have discovered oil.
HCIIP estimate (MMstb)	Oil GIIP P90 – 354 MMstb 44 Bscf P50 – 495 MMstb 62 Bscf P10 – 661 MMstb 83 Bscf
Development type	Water flood development, to be followed by polymer flood.
Number of current production & injection wells	4 E&A wells with 2 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.3.2 Contingent Resources

4.3.2.1 Geoscience review

Gunya is divided into four panels, as shown in Figure 4-22, each centred on a well:

- Gunya SE
- Gunya SW
- Gunya Central
- Gunya North

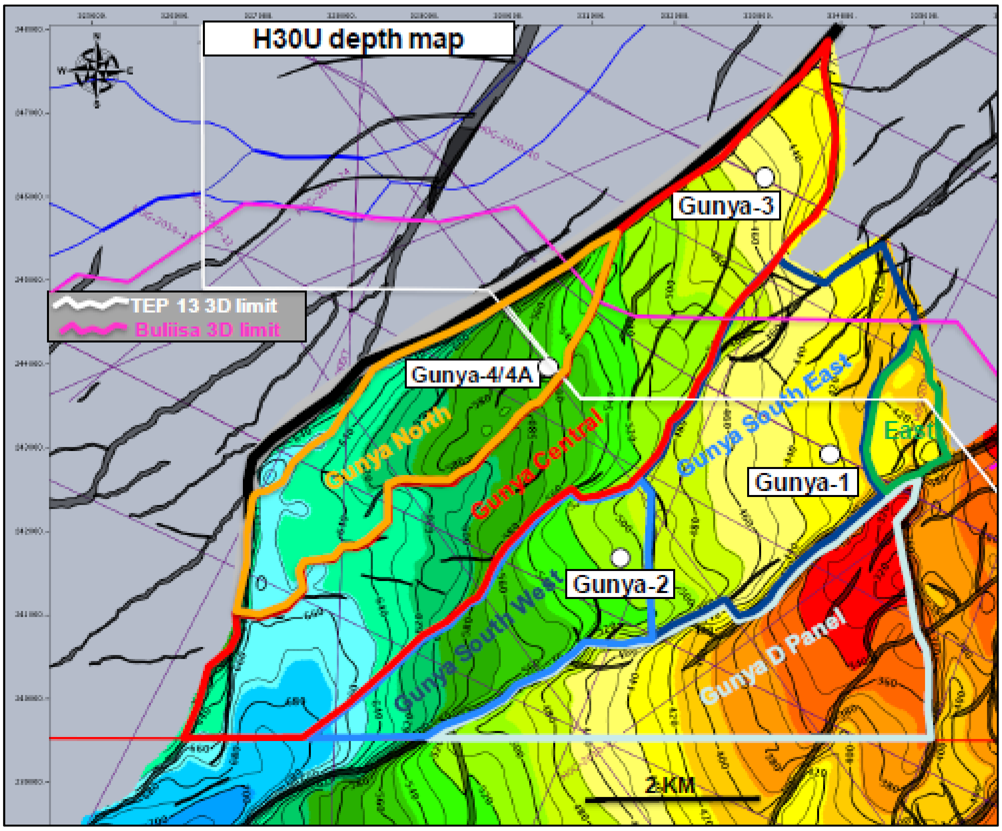


Figure 4-22 Gunya: Total depth map

There are five reservoir intervals, illustrated in Figure 4-23. Hydrocarbons have been encountered in some or all of them, depending on the panel. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

The stratigraphy and structure of Gunya are described in Section 4.2.2.

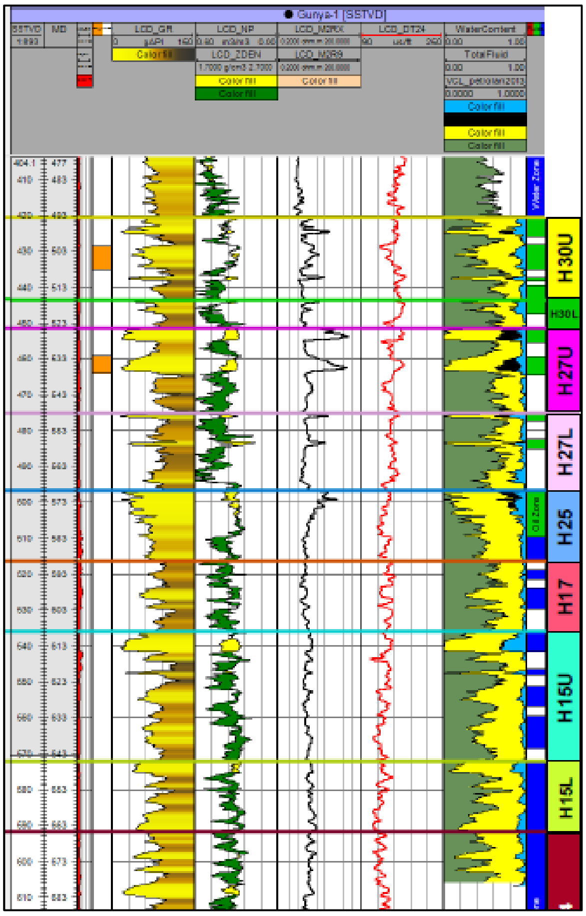


Figure 4-23 Gunya-1 well

TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

The static model follows the same workflow as that of Jobi-Rii. TRACS reviewed the resulting property grids and associated volumes. Again, TRACS has some concerns surrounding the weighting of the seismic attributes versus the wells in the facies and property modelling, as illustrated for the H30L around Gunya-4/4A in Figure 4-24.

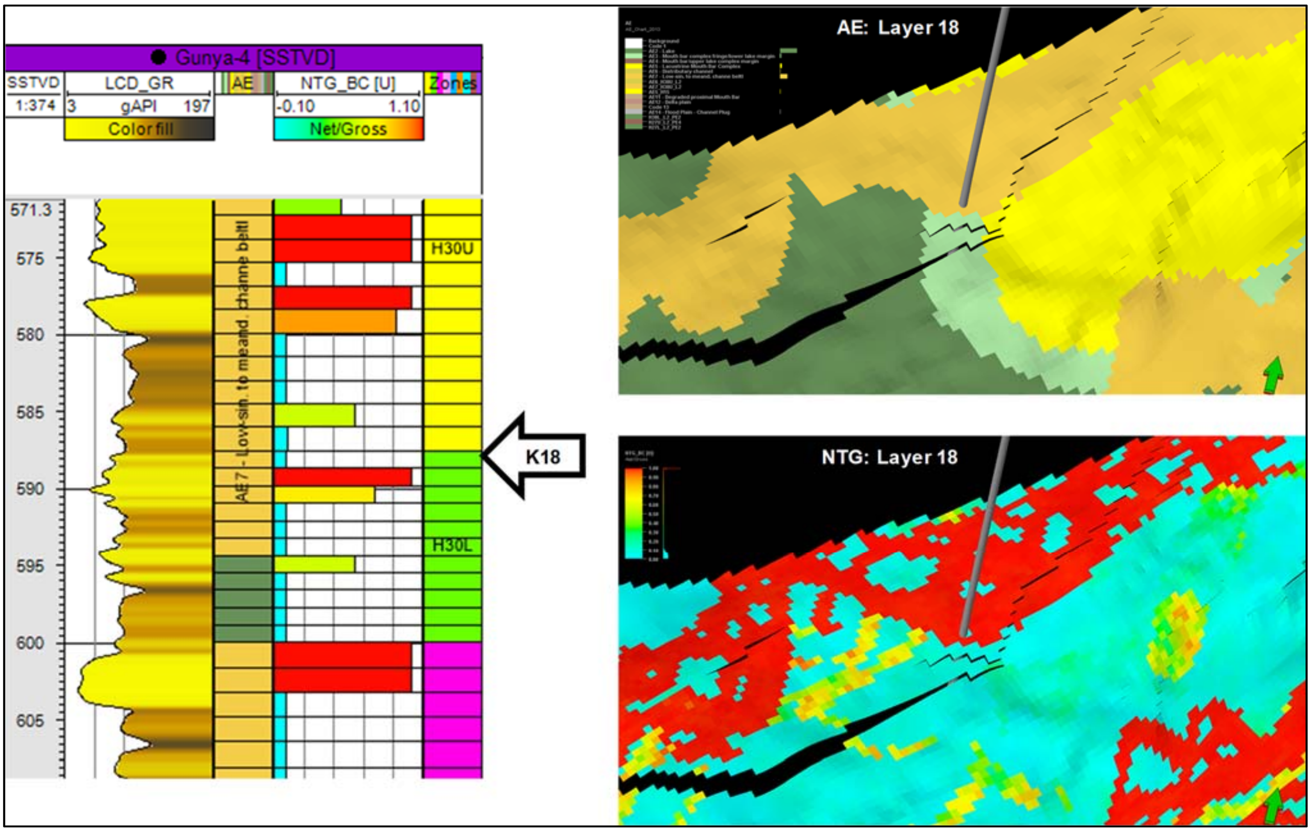


Figure 4-24 Gunya-4 / 4A facies model and NTG (H30L)

4.3.2.2 Petrophysics review

A review of the interpretation was carried out on one well using interpretation input parameters described in the Gunya PRR. The results confirm specifically which of the supplied data had been used for average properties and the interpretations and associated average properties from wells were accepted. The field is comprised of compartments with a single well in each compartment (Figure 4-22). Facies is distributed in the model based on seismic data so the distribution will be part of the big picture. The properties from the wells will represent specific locations but give an indication of the range of properties encountered.

NTG

As is the case with most of the Tilenga fields the NTG in Gunya varies between and within reservoir units throughout the field. The Petrel model has seismic input for the reservoir modelling so it will not be the same as the wells. While the wells only give an indication of the NTG at a single point in their respective compartments, they do indicate that there are locations where the observed NTG might be at an extreme which falls well outside the modelled properties. This does not suggest that the field-wide average could be close to an extreme at any given location (e.g. the minimum is zero net in H30L -Table 4-17), but it does suggest that some of the ranges are possibly narrow and ranges have been adjusted where deemed necessary.

PETREL MODEL				Model/Logs Diff			From Wells (PRR)			
Gunya Fieldwide NTG					NTG		Gunya Fieldwide			
	Low	Mid	High	Low Diff	Mid Diff	High Diff	Zone	Min NTG	Wt Ave NTG	Max NTG
H30U	0.26	0.29	0.33	0.03	0.08	0.13	H30U	0.29	0.37	0.46
H30L	0.24	0.27	0.30	-0.24	-0.16	0.01	H30L	0.00	0.11	0.31
H27U	0.30	0.35	0.40	-0.09	-0.08	0.00	H27U	0.21	0.28	0.40
H27L	0.41	0.46	0.49	-0.30	-0.09	0.13	H27L	0.11	0.37	0.62
H25	0.49	0.52	0.54	-0.06	0.06	0.17	H25	0.43	0.58	0.71

Table 4-17 Gunya Average NTG from wells compared to model

Porosity

The maximum and minimum average porosity from the Gunya wells has a range of at least 5pu across the field. The average porosity from the model is around 25% in all units with zero or 1pu range (Table 4-18). The porosity ranges were widened to reflect the differences observed at the wells and for H30L the whole range was lowered to honour the well data.

PETREL MODEL				Model/Logs Diff			From Wells (PRR)			
Gunya Fieldwide POROSITY					Porosity		Gunya Fieldwide			
	Low	Mid	High	Low Diff	Mid Diff	High Diff	Zone	Min PHIE	Wt Ave PHIE	Max PHIE
H30U	0.23	0.24	0.24	-0.02	0.00	0.02	H30U	0.21	0.24	0.26
H30L	0.26	0.26	0.26	-0.09	-0.07	-0.03	H30L	0.17	0.19	0.23
H27U	0.26	0.26	0.26	-0.01	0.03	0.05	H27U	0.25	0.29	0.31
H27L	0.25	0.25	0.24	-0.03	0.04	0.07	H27L	0.22	0.29	0.31
H25	0.27	0.26	0.26	-0.03	0.02	0.04	H25	0.24	0.28	0.30

Table 4-18 Gunya Average porosity from wells compared to model

Saturation

The average oils saturations are presented in Table 4-19. This is the property with the biggest difference between that from logs and the modelled property. The same methodology is applied as is described in the Jobi-Rii section 4.2.2.2 with a wider range captured to reflect calculations form the logs.

PETREL MODEL				Model/Logs Diff			From Wells (PRR)			
Gunya Fieldwide SO					So		Gunya Fieldwide			
	Low	Mid	High	Low Diff	Mid Diff	High Diff	Zone	Min So	Wt Ave So	Max So
H30U	0.65	0.65	0.72	-0.52	-0.19	-0.08	H30U	0.13	0.47	0.64
H30L	0.69	0.69	0.71	-0.53	-0.39	-0.36	H30L	0.16	0.31	0.35
H27U	0.68	0.71	0.74	-0.23	-0.10	0.01	H27U	0.45	0.61	0.75
H27L	0.72	0.72	0.72	-0.46	-0.25	-0.13	H27L	0.26	0.48	0.59
H25	0.68	0.70	0.71	-0.33	-0.13	-0.06	H25	0.35	0.57	0.65

Table 4-19 Gunya Average oil saturation from wells compared to model

Oil Water Contacts

As is typical of the Tilenga fields the OWCs vary across the fields with separate contacts for at least some of the units (Figure 4-25). The contacts used by Tullow are from a combination of Seismic, pressure and log data. Pressure data has been used to verify the contacts where appropriate. Where pressure data is not available ODT and WUT from logs have been included as input to the final range used.

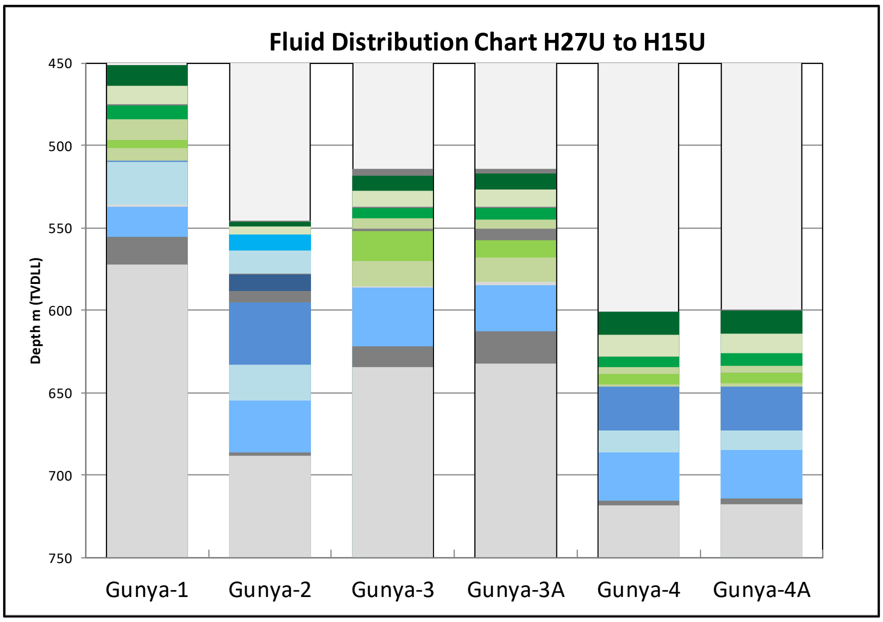


Figure 4-25 Fluid distribution from logs across Gunya

All available data was integrated for the range of contacts used for the volumetric input as presented in the following section.

4.3.2.3 In place volumes

TRACS used the same approach to STOIIP and GIIP assessment as described for Jobi-Rii.

Contacts and GRV

The fluid distribution was reviewed for each pool in order to define Low, Mid and High case contacts. There is a good pressure data set for Gunya. In reservoirs with reliable pressure data these were used to define the Mid case OWC; the uncertainty range is then derived by using different pressure gradient interpretations and/or fluid densities. In reservoirs with no reliable pressure data, ODT and WUT depths were used to define Low and High cases and the average depth was used to define the Mid case. The results for the mid case oil contacts are summarised in Table 4-20.

TRACS has implemented some contact changes. In the H27U and H25 reservoirs the revised Mid contacts lead to large GRV increases. In the case of H27U the increase is mainly in the Central panel whereas for H25 it is in Gunya SW.

Depths in mSL	**Gunya SE -1**	**Gunya SW 2**	**Gunya Central - 3A**	**Gunya North - 4A**
H30U	513	587	620	715
H30L	526	535	620	715
H27U	530	552	618	648
H27L	500	564	618	666
H25	506	572	618	645

Table 4-20 Gunya: Mid case oil contact

The results of the depth uncertainty analysis for Jobi Rii (see Section 4.2.2.3) was also used for Gunya. The impact of depth uncertainty for Gunya is defined as ±10% relative to the reference GRV.

Gunya has identified relatively small gas caps in some reservoirs. The Tullow gas oil contacts were accepted and used to estimate free gas volumes.

The fluid contacts were applied to the static models to generate updated Low, Mid and High GRV values for use in the TRACS @Risk model. A +/- 10% range was applied to the Low and High GRV cases to account for uncertainty relating to structural interpretation and depth conversion.

Properties

Again, TRACS notes the issues surrounding over-reliance on seismic data to guide facies, NTG and other properties and has opted for a wide range by incorporating well averages together with the ranges of properties for the Petrel models. TRACS has used the average value from the mid case static model and well analysis to represent the mid-point for the NTG, porosity and saturation ranges.

The NTG and porosity ranges are taken to be identical for the oil and gas legs in the field. However, the free gas saturation is taken to be 5% higher than the oil saturations given their position in the hydrocarbon column.

The oil formation volume factor is taken to be a constant 1.10 and the gas expansion factor is taken to be a constant 50 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Gunya field are presented in Table 4-21. An average gas oil ratio of 123 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	All reservoir panels	254.4	494.8	660.9
GIIP (Bscf)	Solution gas	43.6	60.9	81.3
	Gas cap gas	0.4	0.9	1.4
	Total Gas	**44.0**	**61.7**	**82.7**

Table 4-21 TRACS estimate of Gunya STOIIP and GIIP

4.3.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Phase 1 waterflood project:H30+H27+H25(all panels)

The Gunya full field dynamic simulation model with water injection development was reviewed to generate an understanding of the recovery mechanism for the pattern flood. The distribution of recovery factor with cumulative STOIIP shows that sweep is complex and that a simple microscopic/ macroscopic analysis cannot easily provide an analytical check of the recovery factor. Although it was noted that the simulation model had a lower STOIIP and a higher recovery than the PRR, the model is an acceptable representation of the reservoir and the model recovery factor was used for the Mid case.

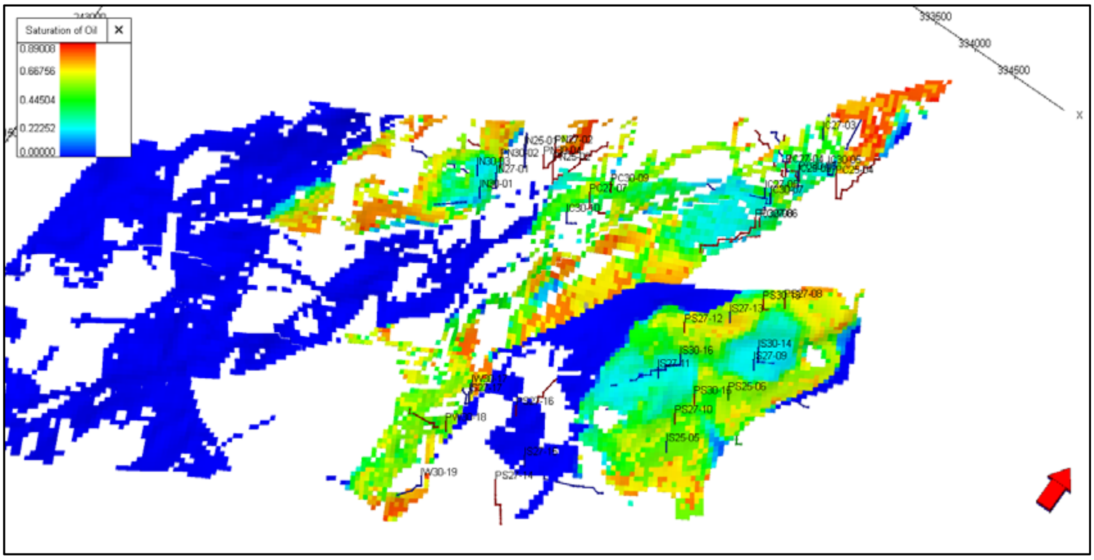


Figure 4-26 Areal view of Gunya reservoir showing complex sweep at 25 years

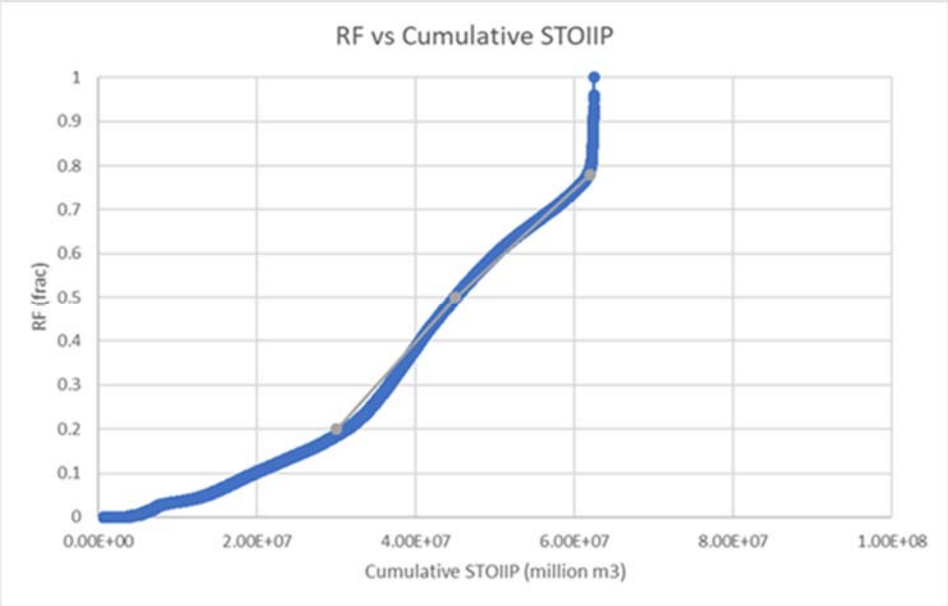


Figure 4-27Recovery factor vs cumulative STOIIP in simulation model cells showing complex sweep

No Low or High case models were provided. Low and High case recovery factors were based on the range of recoveries reported in the uncertainty section of the PRR for relative permeability and Sor (the dominant uncertainty). These give a range of -15% and +25%. The 50 year recovery factors were estimated using the same water cut increase as Jobi-Rii (95% to 97%).

The resulting range of recovery factors for the Gunya Phase 1 oil development is presented in Table 4-22 for 25 and 50 years.

Field	Project		TRACS	
			25 yrs	50 yrs
Gunya	WF H30+H27+H25 (All Panels)	L	0.24	0.29
		M	0.28	0.35
		H	0.35	0.41

Table 4-22 Gunya Phase 1 Recovery Factors

The same process as Jobi Rii (see section 4.2.2.4) was used to derive the production forecasts for Gunya.

The Mid case simulation model without the Central Processing Facility (CPF) constraints was re-run with 50 years of production forecast. The simulation results were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The oil production wells are constrained by a maximum liquid rate of 5 Mblpd, a minimum oil rate of 100 stbd and a maximum water cut of 95%. The production wells are also controlled by the ESP operating gas/liquid ratio range, from 35% to 45%.

The maximum water injection rate of a water injectors is 10 Mbwpd. The maximum injection pressure of injection wells varies from 56 to 79 bars, based on the depth of injection intervals. The water injection rate is also controlled by 100% reservoir voidage replacement. These constraints on water injection wells are required to keep the cap rock integrity.

Furthermore, the maximum oil rate of Gunya Field is set at 30 Mbopd.

The field operating efficiency is 93% and the well operating efficiency is 95%.

The forecasts of oil production profiles were generated from the type curve tool, which combining all Phase 1 fields to meet the constraints of the central process facility and pipeline capacity. The resulting range of profiles for Gunya are presented in Figure 4-28.

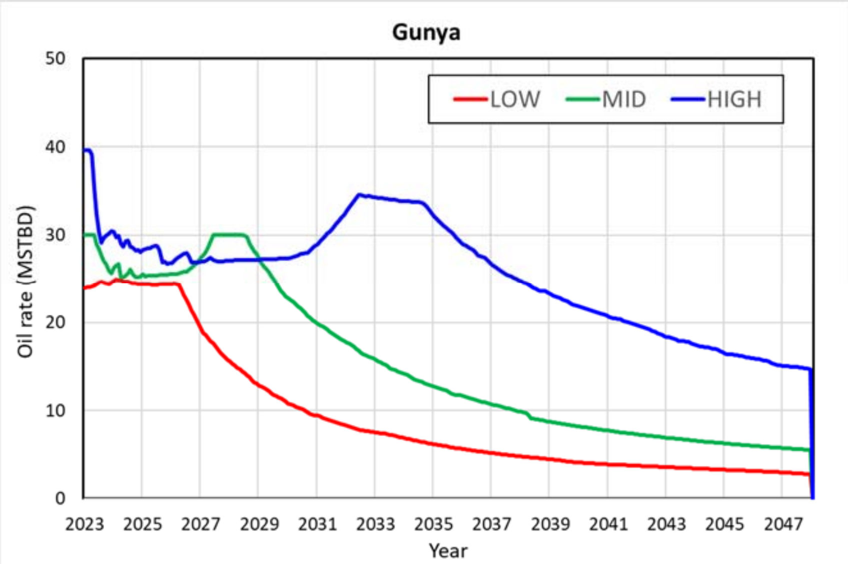


Figure 4-28 Oil production forecast -- Gunya Field

Polymer flood

No models were available for Gunya and it was concluded that the same incremental benefits should be assumed as for Ngiri (see section 4.4.2.4) owing to similar fluid properties and relative permeabilities. These represent incremental recovery factors of +4%/+5%/+6% in the Low, Mid and High cases for 25 year field life.

The range of recovery factors for a polymer flood at 25 and 50 years as estimated by TRACS is presented in Table 4-23.

Field	**Project**		**TRACS**	
			25 yrs	50 yrs
Gunya	PF H30+H27+H25 (all panels)	L	0.28	0.33
		M	0.33	0.40
		H	0.41	0.50

Table 4-23 Gunya Recovery Factors for Polymer Flood

No production profiles were generated for the polymer flood as a commerciality test was not required.

Gas recovery factors

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4).

4.3.3 Estimation of Gunya Contingent Resources

Gunya is a key field in the development of the Albert Basin and is part of the Phase 1 development project. All resources associated with Gunya are classified as Contingent Resources (CR).

4.3.3.1 Contingent Resources Development Pending

The Gunya Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Gunya are presented in Table 4-31. Note that there are no gas DP Contingent Resources as a gas sales solution still needs to be matured.

4.3.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-24.

CR DoH Oil	**Gross (MMbbls)**		
	1C	**2C**	**3C**
Phase 1 WF extension	19.3	36.7	42.5
Polymer Flood	15.2	22.8	58.8
Total all oil DoH	**34.4**	**59.5**	**101.3**

Table 4-24 Gunya Oil DoH Contingent Resource summary

Gas

The solution gas is a by-product of the oil development and has value if a gas development solution is matured. The solution gas recovery associated with the Phase 1 oil project as well as the oil projects been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-25.

CR DoH Gas	**Gross (MMbbls)**		
	1C	**2C**	**3C**
Phase 1	5.2	8.4	13.9
Phase 1 WF extension	1.2	2.3	2.6
Polymer Flood	0.9	1.4	3.6
Total all gas DoH	**7.3**	**12.1**	**20.1**

Table 4-25 Gunya Gas DoH Contingent Resource summary

4.3.3.3 Contingent Resources Development not Viable

The development of the gas caps in Gunya are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

4.3.4 Gunya CR summary

The total Contingent Resources for the Gunya field are presented in Table 4-26 for oil resources and Table 4-27 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	84.1	136.6	225.7	23.8	38.7	64.0
Development on Hold	34.4	59.5	101.3	9.8	16.8	28.7
Total All CR Categories	**118.5**	**196.1**	**327.0**	**33.6**	**55.5**	**92.6**

Table 4-26 Gunya Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	7.3	12.1	20.1	2.1	3.4	5.7
Development currently not viable	0.2	0.6	1.1	0.1	0.2	0.3
Total All CR Categories	**7.5**	**12.6**	**21.2**	**2.1**	**3.6**	**6.0**

Table 4-27 Gunya Gas Contingent Resource summary

4.4 NGIRI FIELD

4.4.1 FIELD BACKGROUND / INTRODUCTION

Field Name	Ngiri
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field consists of seven fault-bound panels in a structural trap (dip and fault closure).
HCIIP estimate (MMstb)	Oil GIIP P90 – 407 MMstb 112 Bscf P50 – 537 MMstb 150 Bscf P10 – 679 MMstb 192 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	7 E&A wells with 2 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.4.2 Contingent Resources

4.4.2.1 Geoscience review

Ngiri is divided into seven fault blocks which have been grouped into five segments, as shown in Figure 4-22. Oil-bearing reservoirs have been encountered in all panels, sometimes capped by gas. The northern extension (Ngiri Terrace) is split off from Ngiri for reporting purposes.

- Ngiri South
- Ngiri NE
- Ngiri West
- Ngiri Central-East
- Ngiri Central-Central

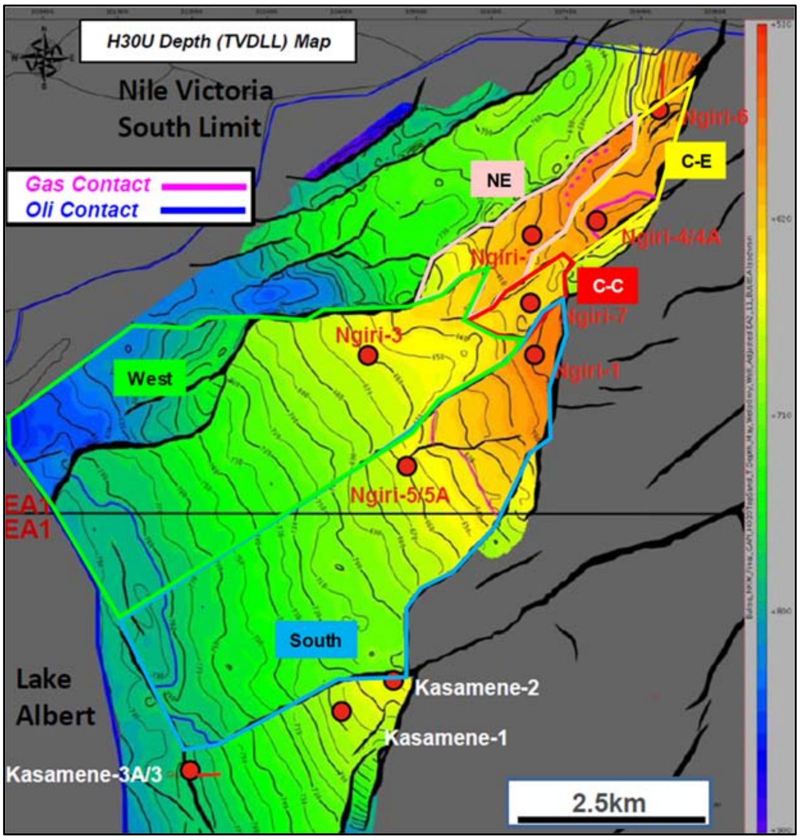


Figure 4-29 Ngiri: Total depth map

There are seven lithological units grouped into three main reservoirs separated by lacustrine shales, see Figure 4-23. Hydrocarbons have been encountered in some or all of them, depending on the panel. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

The stratigraphy and structure of Ngiri are described in Section 4.2.2.1.

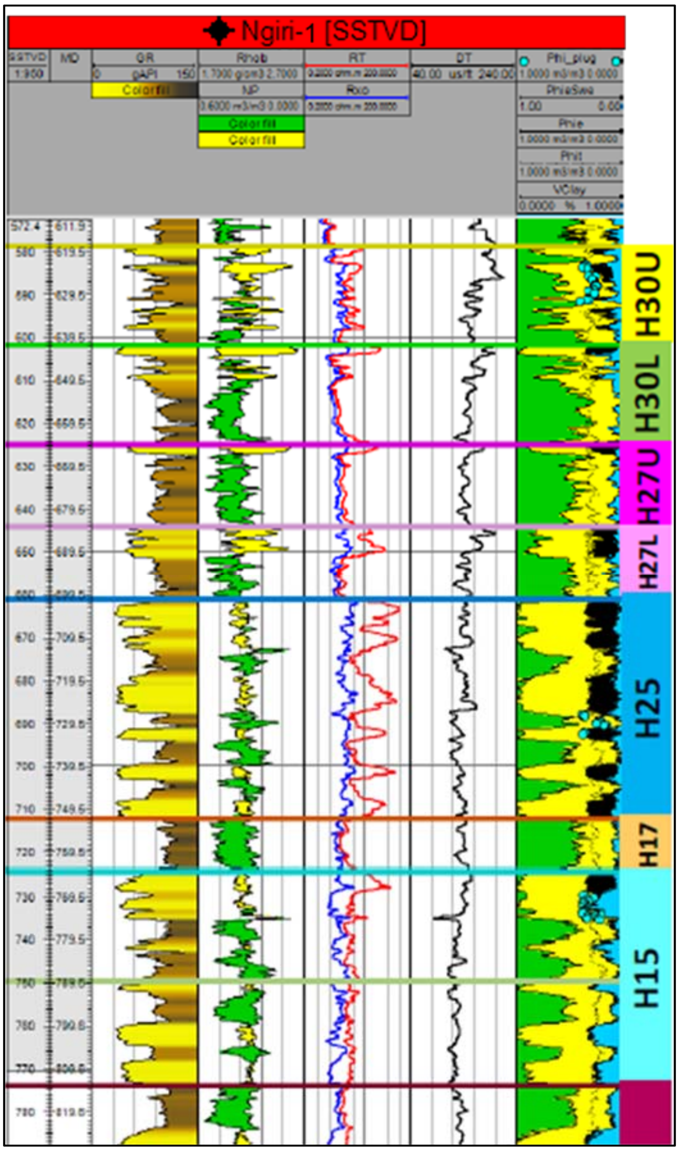


Figure 4-30 Ngiri-1 well

TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

The static model follows the same workflow as that of Jobi-Rii. TRACS reviewed the resulting property grids and associated volumes. Again, TRACS has some concerns surrounding the weighting of the seismic attributes versus the wells in the facies and property modelling, as illustrated for H30L around Ngiri-3 in Figure 4-24.

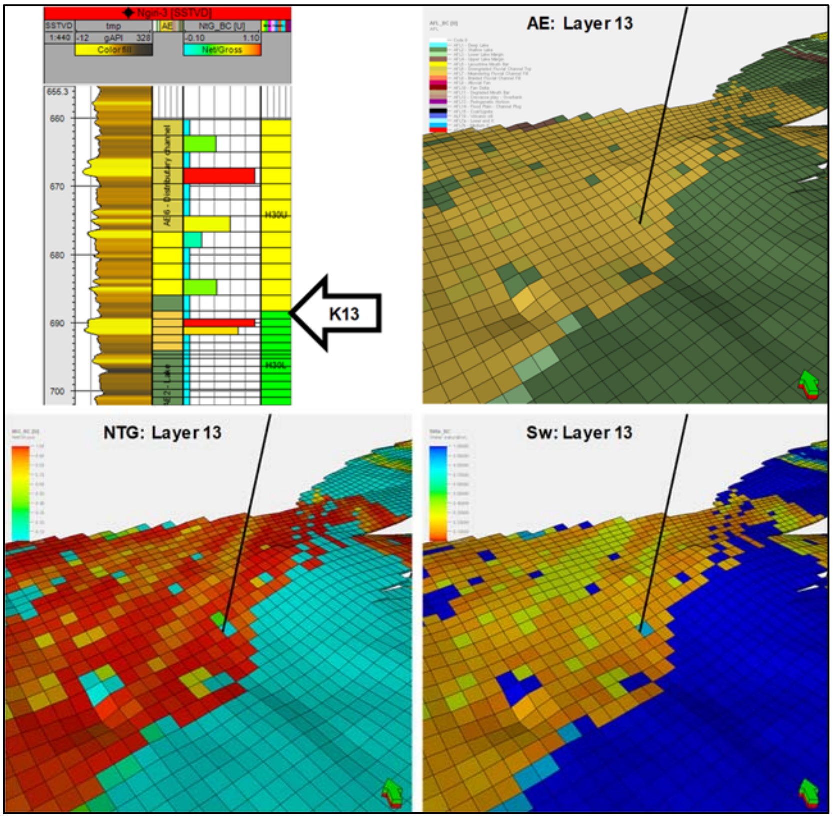


Figure 4-31 Ngiri-3 facies model, NTG and Sw (H30L)

4.4.2.2 Petrophysics review

A quick-look interpretation was carried out on one well using interpretation input parameters described in the Ngiri PRR. The results confirm specifically which of the supplied data had been used for average properties and the interpretations and associated average properties from wells were accepted. The field is comprised of compartments as illustrated in Figure 4-29. Ngiri-6 has been included in this petrophysics review since the Ngiri Terrace can be regarded as a compartment within the same structure. Facies is distributed in the model based on seismic data so the distribution will be part of the big picture. The properties from the wells will represent specific locations.

NTG

Average NTG from the wells illustrates a range in values across the field for all units. Generally the Mid NTG from the model is similar to the Average NTG from wells. The biggest difference in the mid value is in H25 and H19 where both are more optimistic (Table 4-28). In H25 the overall average NTG form wells is 63% with the min and max from an individual well of 32% and 78%. The model captures the high NTG but the range is small with a high mid. This has been addressed in the updated volumes calculations to include a wider range with some influence form the lower average.

Where the mid is similar to the average from logs, but is applied with a narrow range (e.g. H27U), the mid value is kept at a similar value but the range is widened.

Unit H15 is subdivided into H15U and H15L in the petrophysical model and the mid for both has been adjusted to 59% with the ranges adjusted accordingly.

Petrel Field Wide				Model/Logs Diff			From Logs			
	NTG			NTG						
	Low	Mid	High	Low Diff	Mid Diff	High Diff	Zone	Min NTG	Ave NTG	Max NTG
H30U	0.30	0.39	0.47	0.17	0.02	0.00	H30U	0.14	0.36	0.47
H30L	0.16	0.23	0.29	0.10	0.07	0.00	H30L	0.07	0.16	0.29
H27U	0.37	0.43	0.51	0.21	-0.02	-0.27	H27U	0.16	0.45	0.78
H27L	0.35	0.38	0.46	0.35	0.06	-0.18	H27L	0.00	0.32	0.65
H25	0.71	0.77	0.76	0.39	0.14	-0.02	H25	0.32	0.63	0.78
H17	0.15	0.16	0.16	0.15	0.09	-0.08	H17	0.00	0.07	0.24
H15	0.47	0.67	0.72	0.23	0.16	-0.04	H15U	0.24	0.51	0.66
							H15L	0.31	0.51	0.76

Table 4-28 Ngiri NTG from wells compared to model

Porosity

As has generally been observed in the Tilenga fields, the mid porosity from the Total Petrel model is very close to, or the same as, the average net porosity from logs (Table 4-29). The range from the mid value in the model is a maximum of 1pu either way. Data from the logs (supported by core analysis Figure 4-32) indicates that there is a wider range of average porosity throughout the field and this is reflected in the updated range for the volume calculation inputs.

Petrel Field Wide										
	POROSITY			PHI			From Logs			
	Low	Mid	High	Low Diff	Mid Diff	High Diff	Zone	Min Phi	Ave Phi	Max Phi
H30U	0.22	0.23	0.24	0.06	0.02	0.01	H30U	0.17	0.22	0.24
H30L	0.23	0.24	0.24	0.06	0.02	-0.03	H30L	0.17	0.22	0.28
H27U	0.25	0.26	0.27	0.02	-0.01	-0.02	H27U	0.24	0.27	0.30
H27L	0.26	0.26	0.27	0.06	0.01	0.00	H27L	0.20	0.24	0.27
H25	0.28	0.28	0.29	0.01	0.00	-0.01	H25	0.26	0.28	0.30
H17	0.23	0.22	0.22	0.08	0.01	-0.01	H17	0.14	0.21	0.23
H15	0.26	0.27	0.28	0.07	0.01	-0.01	H15U	0.24	0.26	0.29
							H15L	0.19	0.24	0.27

Table 4-29 Ngiri Porosity from wells compared to model

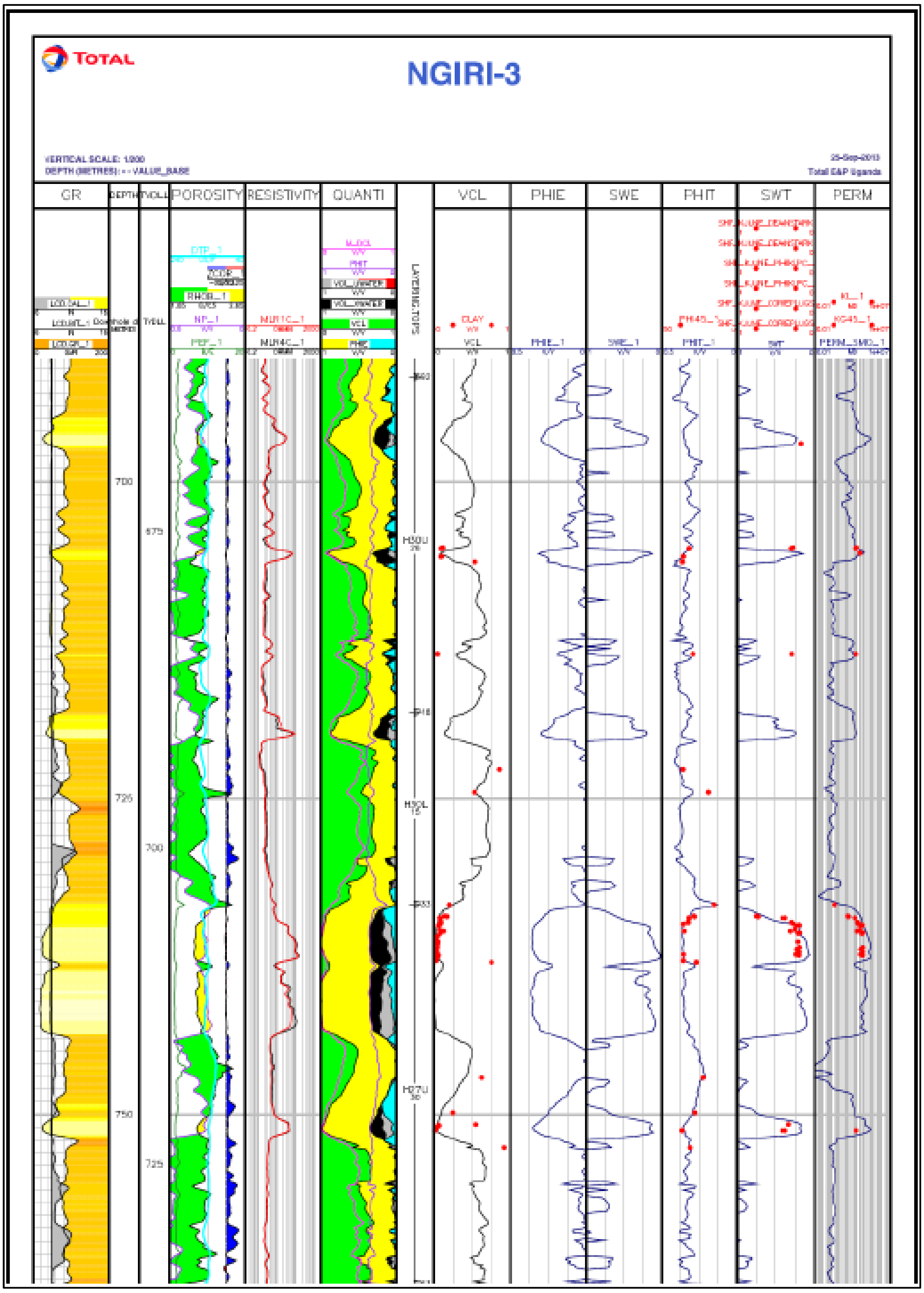


Figure 4-32 From PRR: Ngiri-3 interpretation with core analysis

Saturation

Water saturation has been modelled based on saturation height functions as described in the Jobi-Rii Section 4.2.2.2. The hydrocarbon saturation from logs “Sh” is compared to the modelled hydrocarbon saturation “SO” in Table 4-30. For Ngiri the mid value from the model is fairly similar to field wide average from logs. The high case So from the model mostly includes the high values from the wells but the ranges do not include the low and mid being very similar for most units. The TRACS inputs have been adjusted to include the low case range. In units H30L and H27U the So for the high case volumes has also been increased to reflect the range observed at the wells.

Petrel Field Wide										
	SO			Sh				From Logs		
	Low	Mid	High	Low Diff	Mid Diff	High Diff	Zone	Min Sh	Ave Sh	Max Sh
H30U	0.49	0.54	0.59	0.22	-0.05	-0.10	H30U	0.27	0.59	0.70
H30L	0.53	0.62	0.64	0.16	-0.04	-0.16	H30L	0.37	0.66	0.79
H27U	0.65	0.68	0.69	-0.02	-0.08	-0.11	H27U	0.67	0.76	0.80
H27L	0.70	0.71	0.73	0.27	0.10	0.05	H27L	0.43	0.61	0.68
H25	0.78	0.79	0.80	0.50	0.08	0.05	H25	0.28	0.71	0.75
H17	0.54	0.53	0.51	0.20	0.17	0.15	H17	0.34	0.36	0.37
H15	0.64	0.72	0.70	0.02	0.10	0.09	H15U	0.62	0.62	0.62
							H15L	---	---	---

Table 4-30 Ngiri Average hydrocarbon saturation form logs compared to model

Fluid Contacts

Gas is encountered in the two shallower wells (Ngiri-1 and Ngiri-4A), the remaining wells are deeper than the likely GOC indicated by the fluids in these two wells even though they are in different segments, but high on the structure of the field. No clear fluid contacts are penetrated in any of the wells since there are shales separating the reservoir quality sands – Non-Res in Figure 4-33. The GOCs are driven by a seismic event which also indicates gas updip of Ngiri-2.

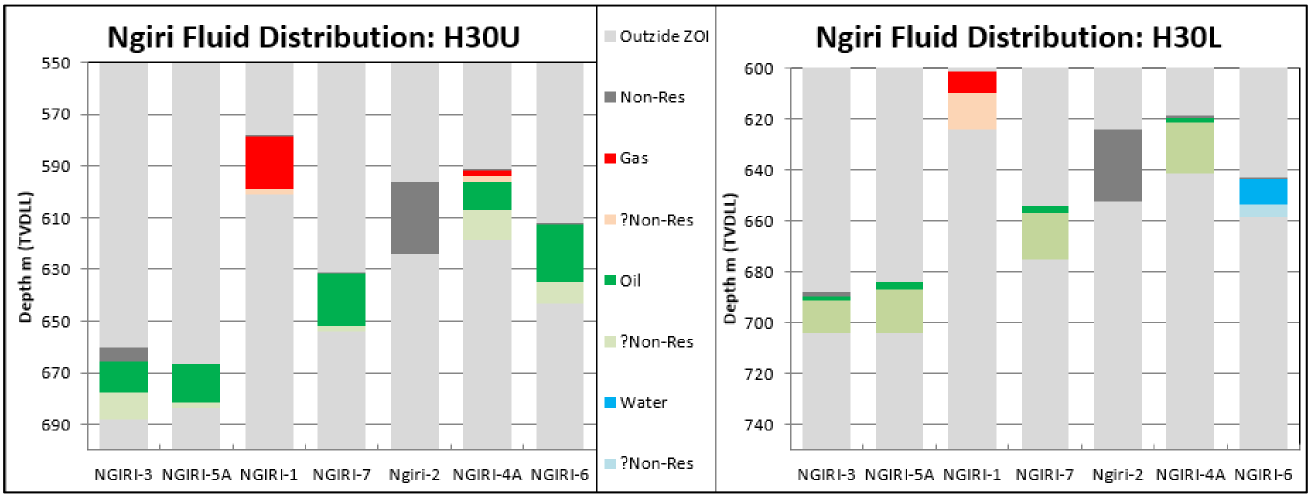


Figure 4-33 Ngiri fluid distribution from Logs: Examples from H30U and H30L

A comprehensive set of pressure data was gathered for the Ngiri field and the hydrocarbon gradients support the wells' indications that H30 is in separate fluid regime to the H27 to H15 reservoir units. The final range of fluid contacts combines all data including the fluid-up-to and fluid-down-to depths from wells while the pressure data drives the mid value for the oil water contacts.

4.4.2.3 In place volumes

TRACS used the same approach to STOIIP and GIIP assessment as described for Jobi-Rii.

Contacts and GRV

The fluid distribution was reviewed for each pool in order to define Low, Mid and High case contacts. There is a good pressure data set for Ngiri. TRACS implemented some contact changes. The pressure data were used to define the Low case contacts in Ngiri as TRACS considers the ODT values to be too pessimistic given the availability and quality of the pressure data. The GOC ranges were not changed from the contacts in the Total Petrel models. The results for the mid case oil-water contacts are presented in Table 4-31.Note that for Ngiri there is interpreted to be a consistent oil accumulation (same contact) across the panels for H27-H15 reservoirs. There is a separate oil accumulation in H30 across four of the panels with an independent (small accumulation) in Central-East.

Depths in mSL	South	NE	West	Central-East	Central-Central
H30U	785	785	785	760	785
H30L					
H27U	731	731	731	731	731
H27L					
H25					
H17					
H15U					

Table 4-31 Ngiri: mid case oil-water contacts

Properties

Again, TRACS notes the issues surrounding over-reliance on seismic data to guide facies, NTG and other properties and has opted for a wide range by incorporating well averages together with the ranges of properties for the Petrel models.

The NTG and porosity ranges are taken to be identical for the oil and gas legs in the field. However, the free gas saturation is taken to be 5% higher than the oil saturations given their position in the hydrocarbon column.

The oil formation volume factor is taken to be a constant 1.12 and the gas expansion factor is taken to be a constant 67 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Ngiri field are presented in Table 4-32. An average gas oil ratio of 254 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	All reservoir panels	406.9	537.1	678.8
GIIP (Bscf)	Solution gas	10.34	136.4	172.4
	Gas cap gas	8.9	13.6	19.2
	Total gas	**112.3**	**150.0**	**191.6**

Table 4-32 TRACS estimate of Ngiri STOIIP and GIIP

4.4.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Phase 1 waterflood project: H30+H27+H25(Main)

The Ngiri full field dynamic simulation model with water injection development was reviewed to generate an understanding of the recovery mechanism for the pattern flood. As with the other reservoirs the sweep is complex, although arguably it is easier to identify swept and largely unswept areas (as can be seen in cross section). However, it is still difficult to check this analytically with fractional flow analysis as large areas of the reservoir also have diffuse flow, i.e. low recovery factors which are not representative of sweep behind a flood front. It was noted that the simulation model had a higher recovery than the PRR due to higher recovery and lower STOIIP. On a like-for-like basis the model recovery factor appeared to be reasonable and was used for the Mid case.

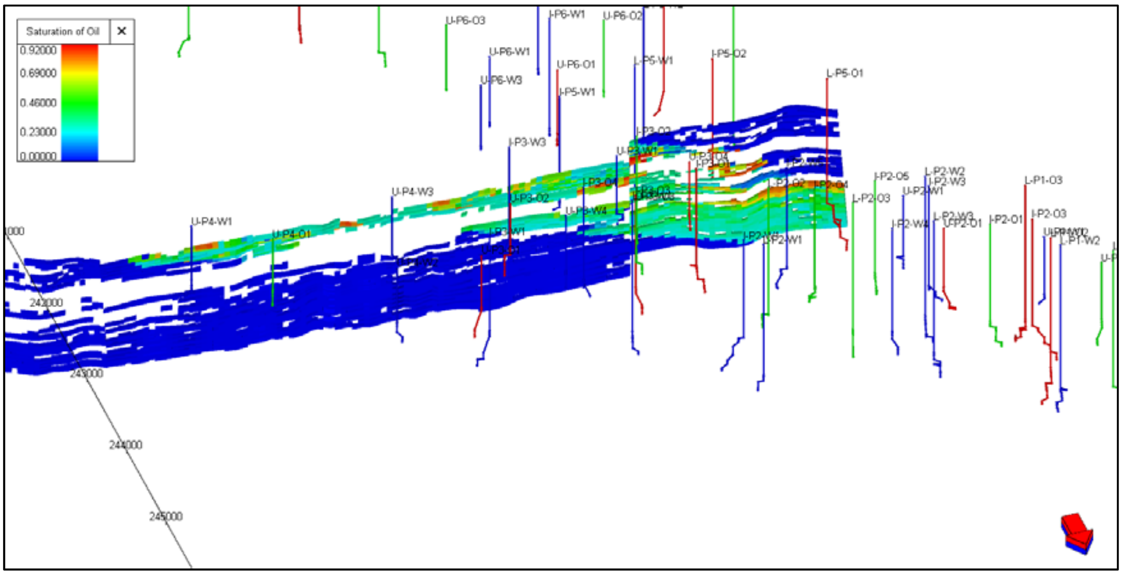


Figure 4-34 Ngiri cross section showing reasonably homogeneous sweep

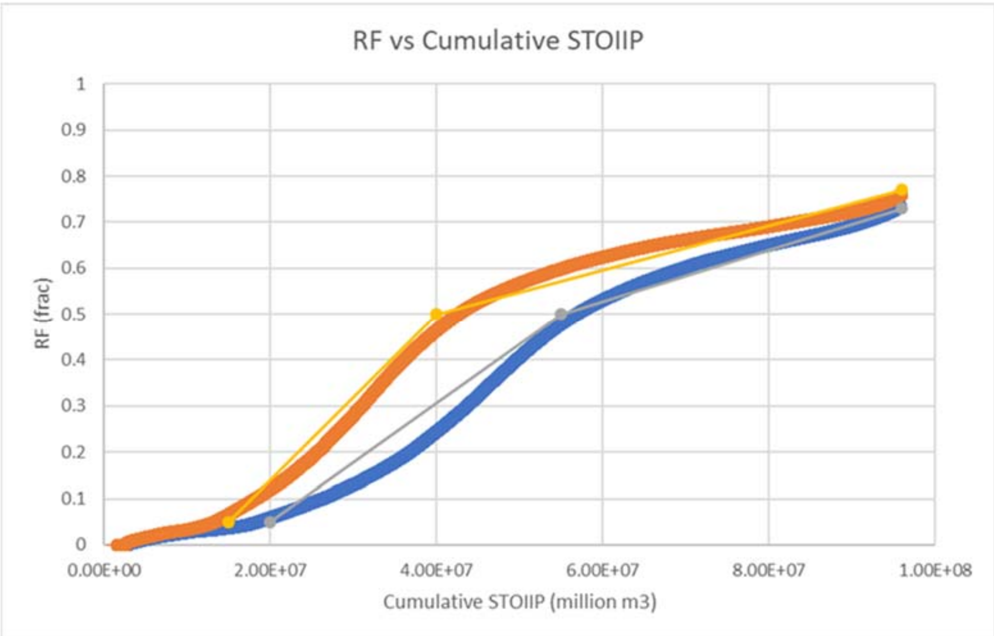


Figure 4-35 Recovery factor vs cumulative STOIIP in simulation model cells showing complex sweep at 25 years (blue) and 50 years (orange)

No Low or High case models were provided. Low and High case recovery factors were based on the range of recoveries reported in the uncertainty section of the PRR for relative permeability and Sor (the dominant uncertainty). These give a range of -15% and +25%. The 50 year recovery factors were estimated using the same water cut increase as the mid case (90% to 94%).

The resulting range of recovery factors for the Ngiri Phase 1 oil development is presented in Table 4-33 for 25 and 50 years.

Field	Project		TRACS	
			25 yrs	50 yrs
Ngiri (& Terrace)	WF H30+H27+H25 (Main+Terrace)	L	0.31	0.38
		M	0.36	0.44
		H	0.45	0.55

Table 4-33 Ngiri Phase 1 Recovery Factors

The same process as Jobi Rii (see section 4.2.2.4) was used to derive the production forecasts for Ngiri.

The Mid case simulation model without the Central Processing Facility (CPF) constraints was re-run with 50 years of production forecast. The simulation results were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The oil production wells are constrained by a maximum liquid rate of 5 to 10 Mblpd, a minimum BHP of 40 bars and a maximum water cut of 98%. The production wells are also controlled by a maximum pressure drawdown of 50 bars and the ESP operating gas/liquid ratio range, from 35% to 45%.

The maximum water injection rate of a water injectors is 10 Mbwpd. The maximum injection pressure of injection wells varies from 79 to 95 bars, based on the depth of injection intervals. The water injection rate is also controlled by 100% reservoir voidage replacement. These constraints on water injection wells are required to keep the cap rock integrity.

Furthermore, the maximum oil rate of Ngiri Field is set at 50 Mbopd.

The field operating efficiency is 93% and the well operating efficiency is 95%.

The forecasts of oil production profiles were generated from the type curve tool, which combining all Phase 1 fields to meet the constraints of central process facility and pipeline capacity. The resulting range of profiles for Ngiri are presented in Figure 4-36.

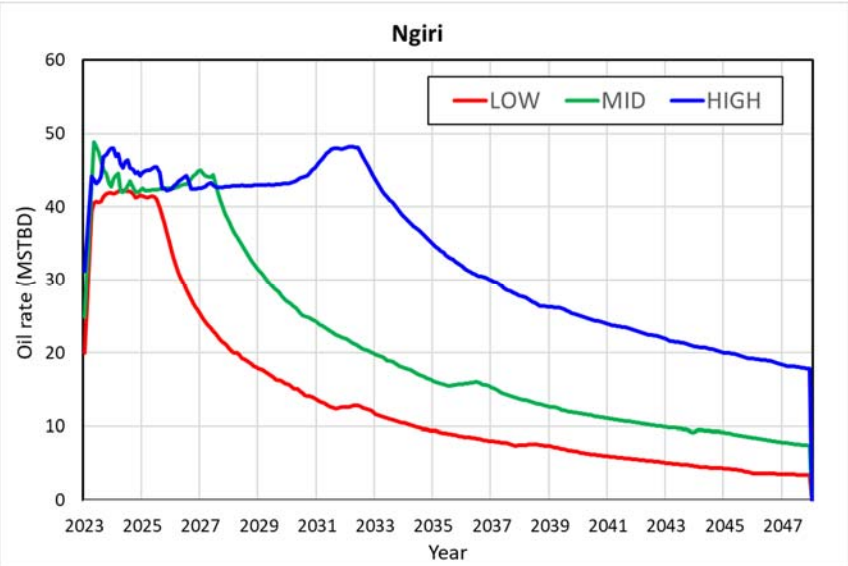


Figure 4-36 Oil production forecast -- Ngiri Field

Polymer flood

No models were available for Ngiri but the incremental benefits of a polymer flood project were documented in the PRR and were consistent with fractional flow analysis. These represent incremental recovery factors of +4%/+5%/+6% in the Low, Mid and High cases for 25 year field life.

The range of recovery factors for a polymer flood at 25 and 50 years as estimated by TRACS is presented in Table 4-34.

Field	**Project**		**TRACS**	
			25 yrs	50 yrs
Ngiri (& Terrace)	WF H30+H27+H25 (Main+Terrace)	L	0.35	0.42
		M	0.41	0.49
		H	0.51	0.62

Table 4-34 Ngiri Recovery Factors for Polymer Flood

No production profiles were generated for this project as a commerciality test was not required.

Gas recovery factors

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4).

4.4.3 Estimation of Ngiri Contingent Resources

Ngiri is a key field in the development of the Albert Basin and is part of the Phase 1 development project. All resources associated with Ngiri are classified as Contingent Resources (CR).

4.4.3.1 Contingent Resources Development Pending

The Ngiri Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Ngiri are presented in Table 4-37. Note that there are no gas DP Contingent Resources as a gas sales solution still needs to be matured.

4.4.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-35.

CR DoH Oil	**Gross (MMbbls)**		
	1C	**2C**	**3C**
Phase 1 WF extension	29.3	45.7	74.5
Polymer Flood	16.0	27.9	44.1
Total all oil DoH	**45.3**	**73.7**	**118.6**

Table 4-35 Ngiri Oil DoH Contingent Resource summary

Gas

The solution gas is a by-product of the oil development and has value if a gas development solution is matured. The solution gas recovery associated with the Phase 1 oil project as well as the oil projects been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-36.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	15.9	24.2	37.9
Phase 1 WF extension	3.7	5.8	9.5
Polymer Flood	2.0	3.5	5.6
Total all gas DoH	**21.6**	**33.6**	**53.0**

Table 4-36 Ngiri Gas DoH Contingent Resource summary

4.4.3.3 Contingent Resources Development not Viable

The development of the gas caps in Ngiri are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

4.4.4 Ngiri CR summary

The total Contingent Resources for the Ngiri field are presented in Table 4-37 for oil resources and Table 4-38 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	125.0	190.8	298.8	35.4	54.1	84.6
Development on Hold	45.3	73.7	118.6	12.8	20.9	33.6
Total All CR Categories	**170.3**	**264.5**	**417.4**	**48.3**	**74.9**	**118.2**

Table 4-37 Ngiri Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	21.6	33.6	53.0	6.1	9.5	15.0
Development currently not viable	4.5	8.8	15.4	1.3	2.5	4.4
Total All CR Categories	**26.1**	**42.4**	**68.4**	**7.4**	**12.0**	**19.4**

Table 4-38 Ngiri Gas Contingent Resource summary

4.5 KASAMENE / WAHRINDI FIELDS

4.5.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Kasamene-Wahrindi**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are good quality, high permeability sands of ?Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field is formed by structural trapping (dip and fault closure).
HCIIP estimate	Oil GIIP P90 – 124 MMstb 44 Bscf P50 – 162 MMstb 58 Bscf P10 – 208 MMstb 74 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	4 E&A wells with 2 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.5.2 Contingent Resources

4.5.2.1 Geoscience review

Kasamene and Wahrindi are part of the same structure and will be part of a combined development.

The Kasamene-Wahrindi structure is divided into three segments, as shown in Figure 4-37, each centred on a well:

- Kasamene: Kasamene-1, 2 & 3
- Wahrindi North: Kasamene-3A
- Wahrindi South: Wahrindi-1

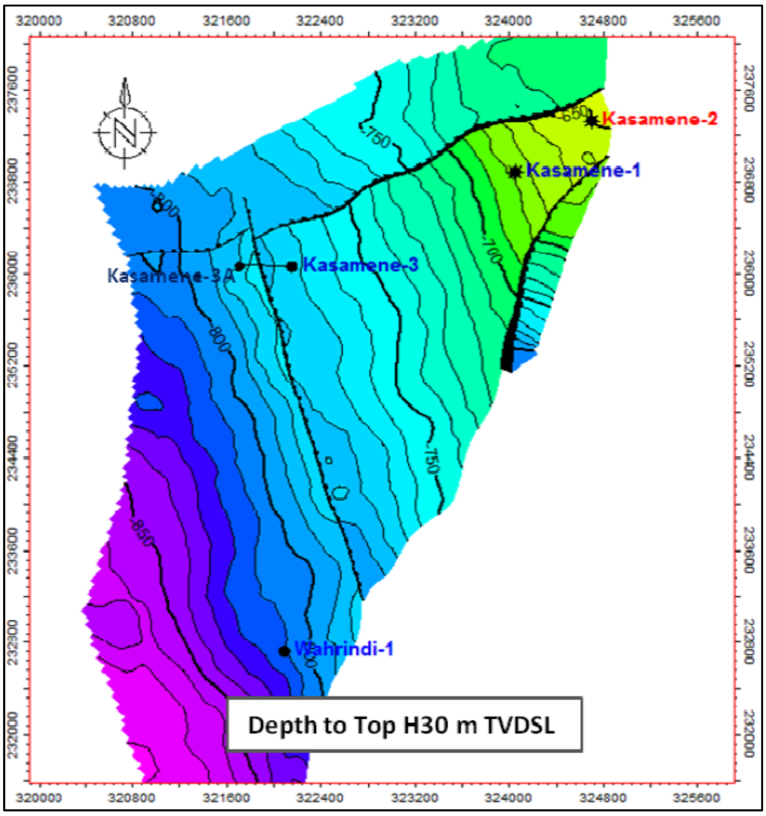


Figure 4-37 Kasamene-Wahrindi: Tullow depth map

There are seven reservoirs, illustrated in Figure 4-38. Hydrocarbons have been encountered in some or all of them, depending on the panel. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

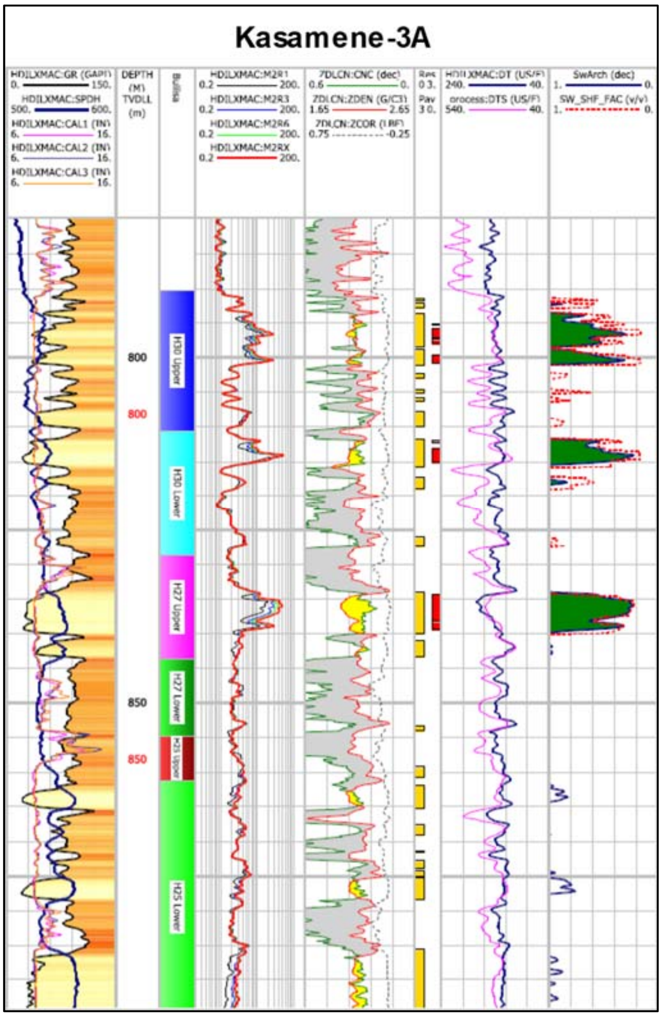


Figure 4-38 Kasamene-3A well

A base case structural model of the Kasamene-Wahrindi fields was built in time and then depth converted using appropriate velocity grids. TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

Conceptual models were developed using well and seismic data and incorporating local analogues. Seismic reflectivity and inversion data provide a broad understanding of which areas are sand prone and which areas are shale prone. The seismic data were used together with regional geological understanding to define geological geometries, such as fans and channels, as illustrated in Figure 4-39. The main architectural elements are channelised sand bodies, isolated fluvial channels, lacustrine sand bodies and lacustrine shales. The amount of heterogeneity and connectivity varies between units. Some intervals display good vertical connectivity whereas others have good lateral connectivity and clear baffling in the vertical direction.

Petrophysical properties are distributed within the facies framework using the following steps:

- net sand definition from logs
- rock typing: based on electro-facies classification from logs
- porosity distribution per facies
- permeability: from poro-perm model and based on core
- saturation: from Sw-height model based on core

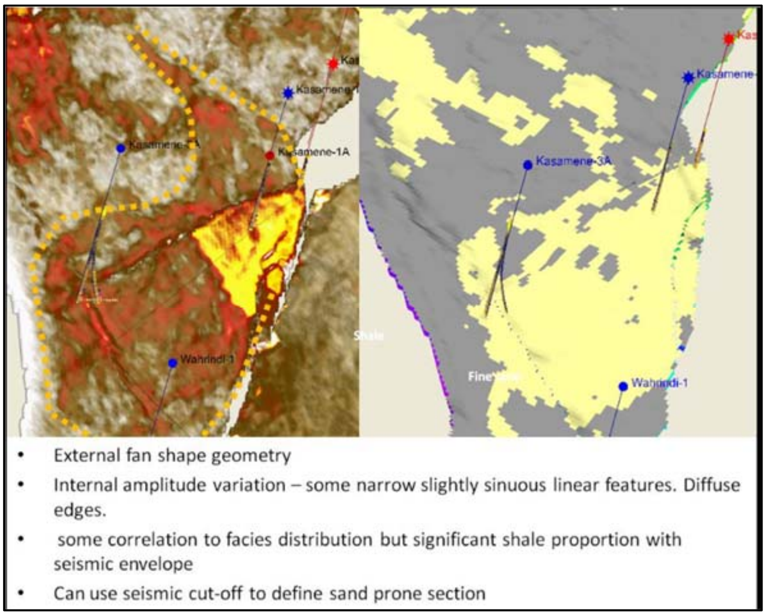


Figure 4-39 Kasamene-Wahrindi: H30 attribute map and interpretation of sand prone area

It is clear that in this type of depositional environment rapid changes occur both laterally and vertically. While some of these variations may be captured by seismic data, others are not. The conceptual facies models generated by Tullow represent a range of valid realisations but there is a possibility that the seismic data are misleading resulting in an incorrect view of the 3D distribution of the architectural elements.

4.5.2.2 Petrophysics review

No digital version of the interpretation from logs is available but the individual CPIs are supplied. Kasamene-1 has measured porosity from core analysis which gives confidence in the interpretation and the results are deemed to be robust. The average properties as listed in the PRRs for Kasamene and Wahrindi are compared to the modelled properties in this case.

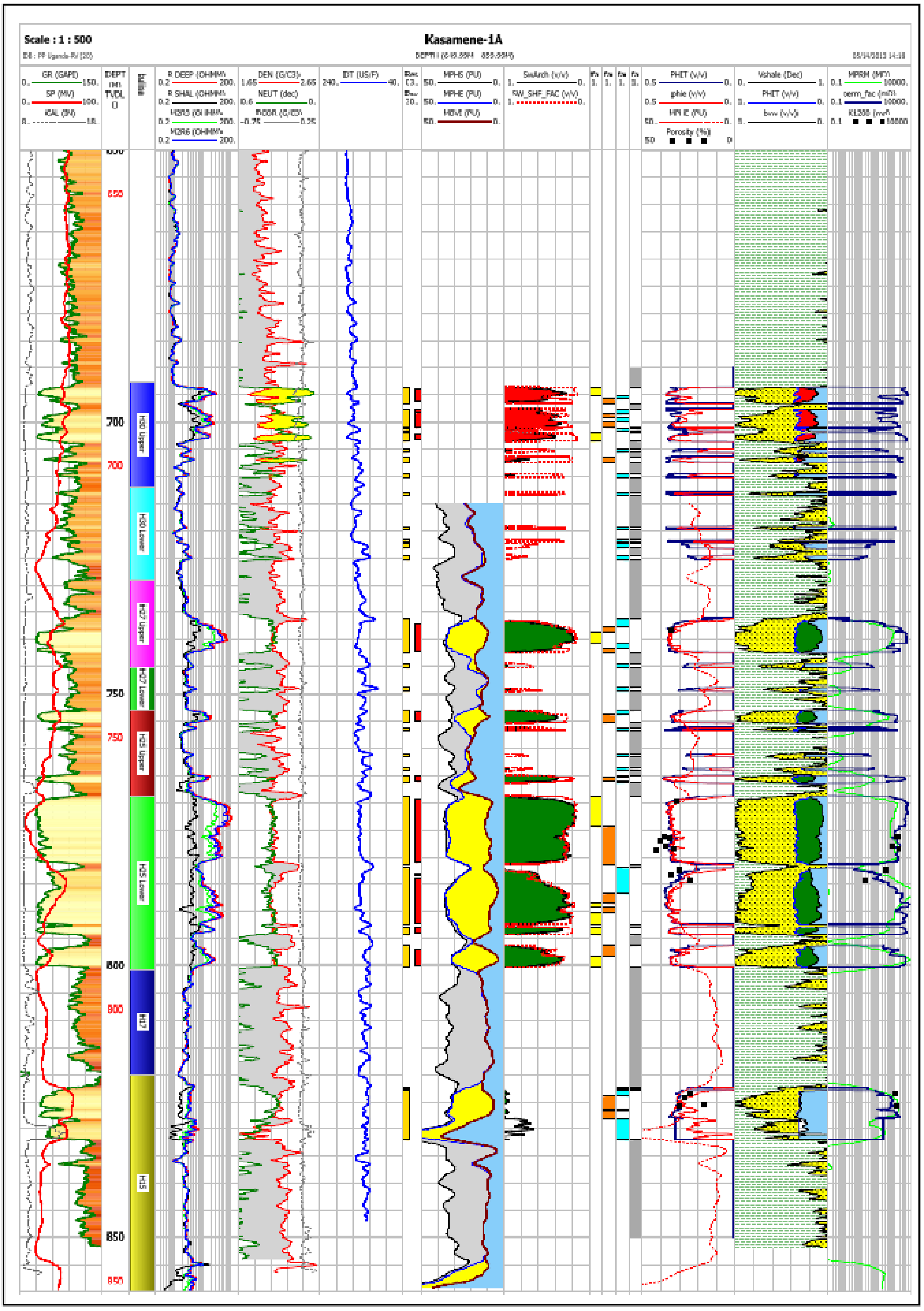


Figure 4-40 Kasamene-1A CPI (from client data)

NTG

The NTG values in Table 4-39 compare the range of average NTG from wells with the range from the back-calculated Petrel model. Generally the range of NTG from the model is narrow. Where the high or low NTG from the model is similar to the corresponding value from wells then the mid is very different with the whole range from the model being close to the corresponding high or low. These are not always biased toward the high or low e.g. H30L has a narrow (low) range of just 14% to 18% while H25L1 is all on the high side with a range of 77% to 89%. For the TRACS input the mid value honours the wells and model while the range is generally wider for each unit.

	KW Model NTG			NTG Diff			KW NTG from logs			
	Low	Mid	High	Min	Wt Ave	Max	Min	Wt Ave	Max	
H30U	0.27	0.28	0.32	0.02	0.26	0.29	0.29	0.55	0.61	H30U
H30L	0.14	0.15	0.18	-0.04	0.15	0.42	0.11	0.30	0.60	H30L
H27U	0.31	0.32	0.33	-0.22	0.00	0.24	0.10	0.32	0.57	H27U
H27L	0.15	0.18	0.25	-0.15	0.08	0.49	0.00	0.26	0.75	H27L
H25U	0.10	0.10	0.09	0.05	0.15	0.24	0.15	0.26	0.33	H25U
H25L1	0.80	0.77	0.89	-0.32	-0.08	-0.01	0.48	0.69	0.88	H25L
H25L2	0.61	0.56	0.68	-0.13	0.13	0.20	0.48	0.69	0.88	H25L

Table 4-39 Kasamene-Wahrindi NTG from wells compared to model

Porosity

The mid porosity from the model and from wells are very similar for the Kasamene and Wahrindi. The maximum and minimum average porosity from the wells for any unit has a range of around 5pu to 10pu across the field. The average porosity from the model is around 30% in all units with zero or 1pu range (Table 4-40). The porosity ranges were widened to reflect the differences observed at the wells and for H30L the whole range was lowered to honour the well data.

	KW Model POROSITY			PHI Diff			KW POROSITY from logs			
	Low	Mid	High	Min	Wt Ave	Max	Min	Wt Ave	Max	
H30U	0.32	0.31	0.31	-0.04	-0.01	0.02	0.28	0.30	0.34	H30U
H30L	0.31	0.31	0.31	-0.06	-0.02	-0.01	0.25	0.29	0.30	H30L
H27U	0.33	0.32	0.32	-0.10	-0.01	0.02	0.23	0.31	0.34	H27U
H27L	0.33	0.32	0.32	-0.11	-0.02	0.01	0.22	0.30	0.32	H27L
H25U	0.31	0.31	0.30	-0.09	-0.02	0.03	0.22	0.29	0.33	H25U
H25L1	0.33	0.33	0.33	-0.03	-0.01	0.03	0.30	0.32	0.36	H25L
H25L2	0.32	0.33	0.32	-0.02	0.00	0.04	0.30	0.32	0.36	H25L

Table 4-40 Kasamene-Wahrindi Porosity from wells compared to model

Saturation

Saturations in the model are from saturation height functions which are demonstrated to be a good match to Sw from logs. The resulting mid So from the model is generally close to field wide average from logs (Table 4-41). The range applied in the model is narrow though so the TRACS range has been expanded to include the range from wells where necessary. In some of the units e.g. H25U the range is small from both sources.

	Kw Model SO			So Diff			Kw SO from Logs			
	Low	Mid	High	Min	Wt Ave	Max	Min	Wt Ave	Max	
H30U	0.53	0.57	0.62	0.02	0.00	-0.01	0.54	0.56	0.61	H30U
H30L	0.50	0.52	0.55	0.09	0.08	0.08	0.58	0.60	0.63	H30L
H27U	0.68	0.67	0.69	-0.13	0.01	0.07	0.55	0.68	0.75	H27U
H27L	0.69	0.68	0.69	-0.08	-0.68	-0.08	0.61		0.61	H27L
H25U	0.51	0.55	0.56	0.00	-0.02	0.00	0.50	0.53	0.56	H25U
H25L1	0.78	0.83	0.84	-0.37	-0.18	-0.07	0.41	0.65	0.77	H25L
H25L2	0.66	0.76	0.77	-0.25	-0.11	0.01	0.41	0.65	0.77	H25L

Table 4-41 Kasamene-Wahrindi Oil Saturation from wells compared to model

Contacts

No wells penetrate a clear fluid contact since there are non-reservoir intervals between the reservoir quality sands. The fluids observed in the wells do give fluid-down-to and fluid-up-to information to identify which depth intervals can contain the potential fluid contacts. The map and cross section diagram in Figure 4-41 summarise the mid contacts identified from the fluids in the wells and where they vary due to structure.

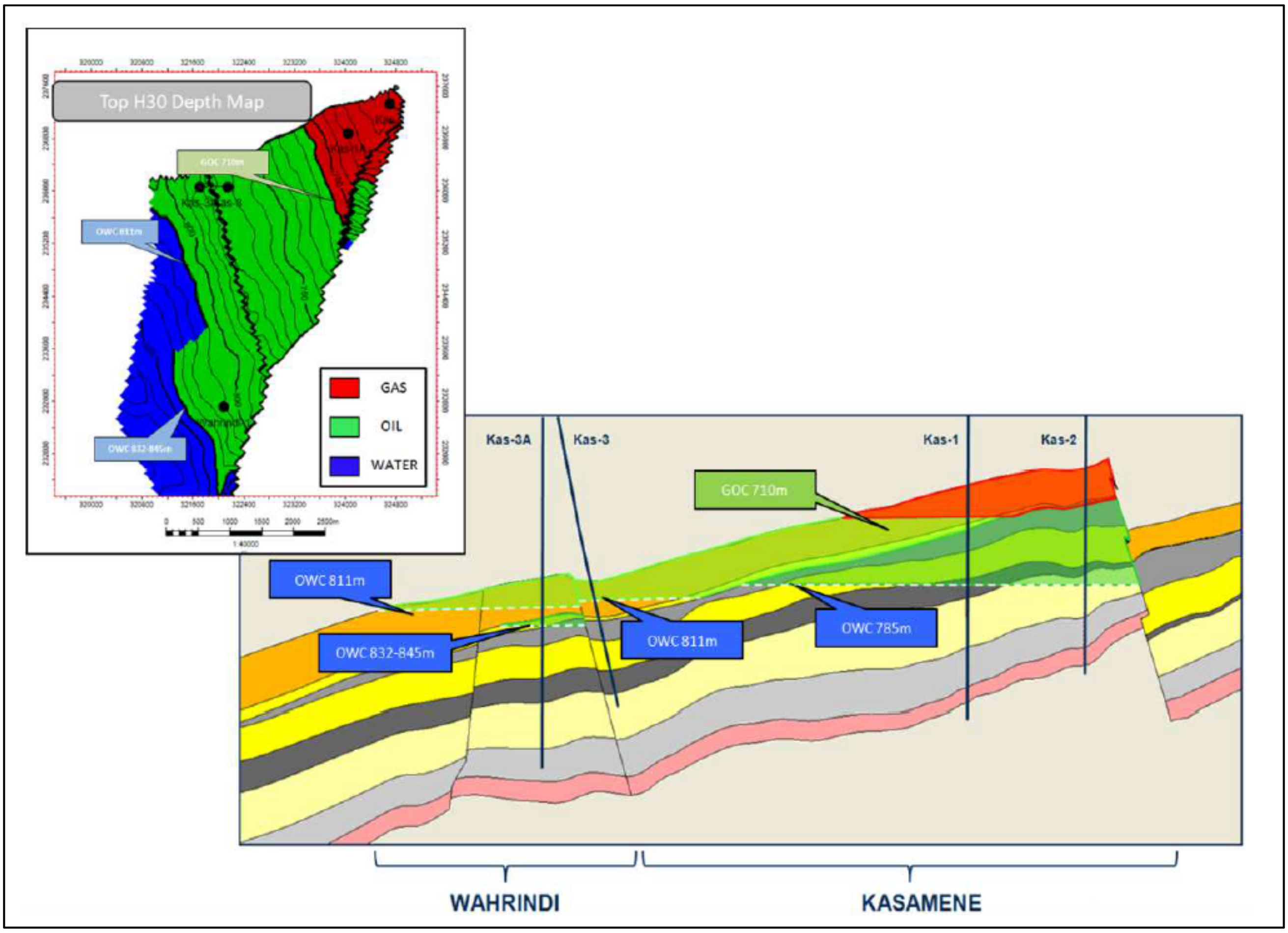


Figure 4-41 From PRR: Kasamene and Wahrindi Segments and contacts

4.5.2.3 In place volumes

Tullow undertook a full stochastic uncertainty analysis to generate P90-P50-P10 models for in place volume calculations. TRACS used the same approach to STOIIP and GIIP assessment as described for Jobi-Rii.

Contacts and GRV

The fluid distribution was reviewed for each pool in order to define Low, Mid and High case contacts. There is a good pressure data set for Kasamene. In reservoirs with reliable pressure data these were used to define the Mid case OWC; the uncertainty range is then derived by using different pressure gradient interpretations and/or fluid densities. In reservoirs with no reliable pressure data, ODT and WUT depths were used to define Low and High cases and the average depth was used to define the Mid case. The results for the mid case oil-water contacts are summarised in Table 4-42.

TRACS implemented some contact changes but they have no material impact on the GRV in Kasamene.

There is a large degree surrounding the extents of the OWC regions within Wahrindi. The boundary between Wahrindi North and South is varied in the P90-P50-P10 cases, as illustrated in Figure 4-42.

Depths in mSL	**Kasamene**	**Wahrindi North**	**Wahrindi South**
H30	801	811	832
H27	801	831	864
H25	781.9	781.9	

Table 4-42 Kasamene-Wahrindi: mid oil-water contact

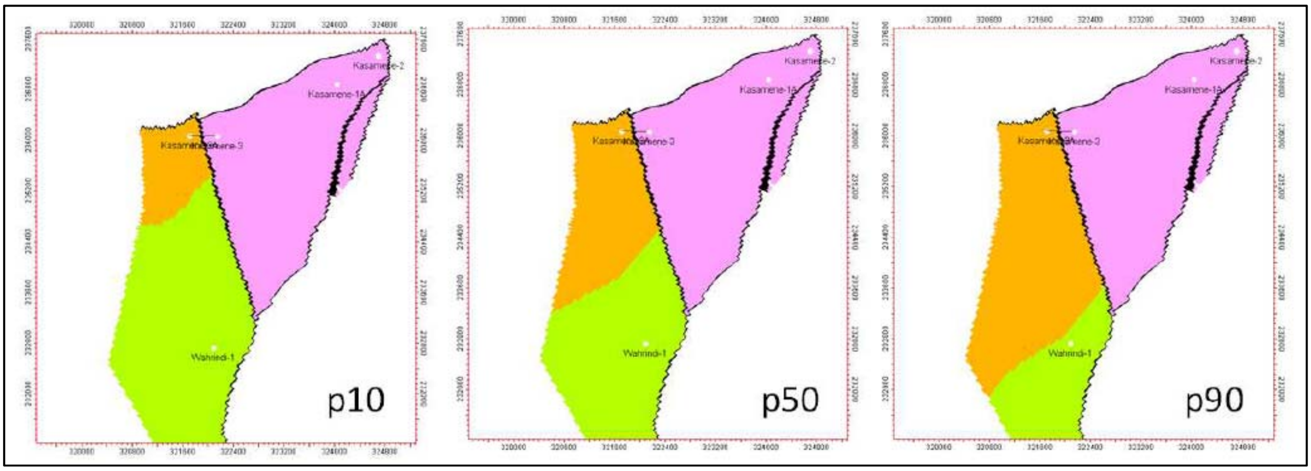


Figure 4-42 Lateral extents of Wahrindi OWC segments in H27-H30

Kasamene has identified relatively small gas caps in some reservoirs. The Tullow gas oil contacts were accepted and used to estimate free gas volumes. Wahrindi has no observed free gas in place.

The fluid contacts were applied to the static models to generate updated Low, Mid and High GRV values for use in the TRACS @Risk model. A +/- 10% range was applied to the Low and High GRV cases to account for uncertainty relating to structural interpretation and depth conversion.

Properties

The properties have been varied as part of the stochastic workflow. Again, it should be noted that (1) well averages of NTG might not be indicative of 3D NTG averages and (2) seismic attributes may not be representative of 3D properties.

TRACS has used the average value from the mid case static model and well analysis to represent the mid-point for the NTG, porosity and saturation ranges. However, for the Wahrindi panels there has been more weighting put on the Wahrindi well averages.

The NTG and porosity ranges are taken to be identical for the oil and gas legs in the field. However, the free gas saturation is taken to be 5% higher than the oil saturations given their position in the hydrocarbon column.

The oil formation volume factor is taken to be a constant 1.11 and the gas expansion factor is taken to be a constant 50 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Kasamene-Wahrindi fields are presented in Table 4-43. An average gas oil ratio of 308 scf/bbl has been used to estimate the solution gas volumes.

	Reservoir / areas	P10	P50	P90
STOIIP (MMbbls)	Kasamene	99.4	127.0	160.2
	Wahrindi	24.2	35.4	47.4
	Total	**123.6**	**162.4**	**207.6**
GIIP (Bscf)	Solution gas	38.1	50.0	63.9
	Gas cap gas	5.8	8.0	10.4
	Total Gas	**43.9**	**58.0**	**74.3**

Table 4-43 TRACS estimate of Kasamene-Wahrindi STOIIP and GIIP

4.5.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Phase 1 waterflood project

The Kasamene dynamic model provided by Tullow included the Wahrindi field. As in the Tilenga BoD, the Kasamene and Wahrindi fields are treated as a single entity (KW) in terms of dynamic model and production forecast.

The KW full field dynamic simulation model with water injection development was reviewed to generate an understanding of the recovery mechanism for the pattern flood. It was noted that it was difficult to break out the Wahrindi components of the model but consistent recovery factors were reported in the respective PRRs. The PRR recovery factors were used for the Mid case. Wahrindi has an areal sweep efficiency which is about 50% of Kasamene.

Low and High case models were provided but appeared to be dominated by static uncertainties and particularly for Kasamene had a narrow range of recovery factors. Low and High case recovery factors were therefore based on the range of recoveries reported in the uncertainty section of the PRR for relative permeability and Sor (the dominant uncertainties), using fractional flow analysis. These give a range of -15% and +20%. The KW model includes significant shut-ins beyond 25 years and exhibits limited water cut increase.

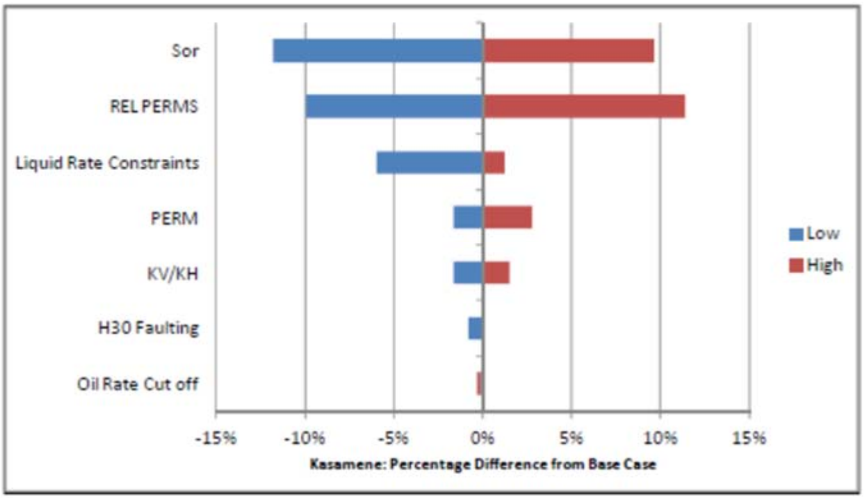


Figure 4-43 Figure from PRR showing dynamic uncertainty is dominated by relative permeability and Sor

The resulting range of recovery factors for the Kasamene-Wahrindi Phase 1 oil development is presented in Table 4-44 for 25 and 50 years. The 50 year recovery factors were estimated using the same incremental benefit as Gunya.

Field	Project		TRACS	
			25 yrs	50 yrs
Kasamene	Waterflood	L	0.31	0.38
		M	0.36	0.45
		H	0.43	0.50
Wahrindi	Waterflood	L	0.15	0.18
		M	0.18	0.23
		H	0.22	0.26

Table 4-44 KW Phase 1 Recovery Factors

The same process as Jobi Rii (see section 4.2.2.4) was used to derive the production forecasts for KW.

The Mid case simulation model without the Central Processing Facility (CPF) constraints was re-run with 50 years of production forecast. The simulation results were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The oil production wells are constrained by maximum liquid rate of 5 ~8.5 Mblpd, minimum BHP of 700 ~ 800 psia, maximum pressure drawdown of 300 psia, minimum oil rate of 100 bopd and a maximum water cut of 95%.

The maximum water injection rate of a water injectors is 10 Mbwpd. The maximum injection pressure of injection wells varies from 1420 to 1590psi, based on the depth of injection intervals. The water injection rate is also controlled by 100% reservoir voidage replacement. These constraints on water injection wells are required to keep the cap rock integrity.

Furthermore, the maximum oil rate of KW block is set at 20 Mbopd, taking account of the field uptime.

The field operating efficiency is 93% and the well operating efficiency is 95%.

The forecasts of oil production profiles were generated from the type curve tool, which combining all Phase 1 fields to meet the constraints of central process facility and pipeline capacity. The resulting range of profiles for KW are presented in Figure 4-44.

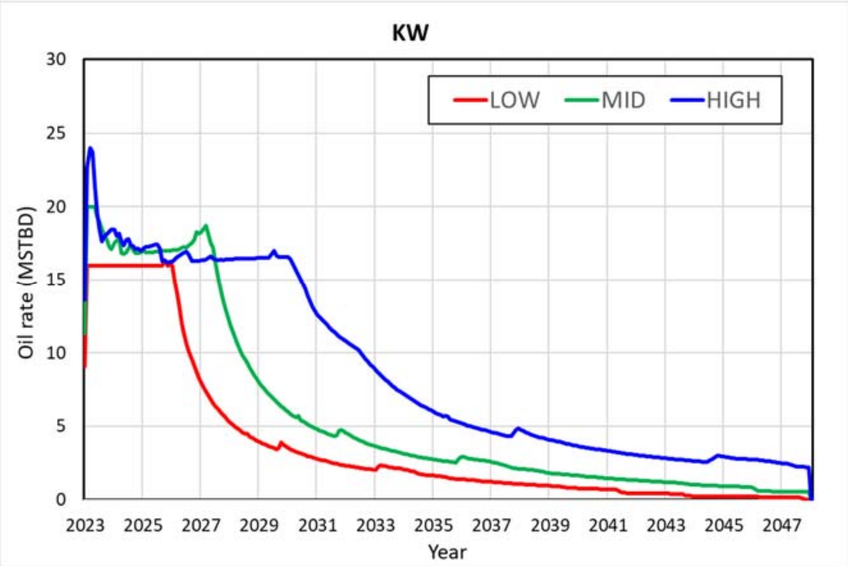


Figure 4-44 Oil production forecast – KW fields

Polymer flood

No models were available for KW and it was concluded that the same incremental benefits should be assumed as for Ngiri owing to similar fluid properties and relative permeabilities. These represent incremental recovery factors of +4%/+5%/+6% in the low, mid and high cases for 25 year field life.

The range of recovery factors for a polymer flood at 25 and 50 years as estimated by TRACS is presented in Table 4-45.

Field	**Project**		**TRACS**	
			25 yrs	50 yrs
Kasamene	WF H30+H27+H25	L	0.35	0.42
		M	0.41	0.49
		H	0.49	0.59
Wahrindi	WF H30+H27+H25	L	0.19	0.23
		M	0.23	0.28
		H	0.28	0.34

Table 4-45 KW Recovery Factors for Polymer Flood

No production profiles were generated for this project as a commerciality test was not required.

Gas recovery factors

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4). Note that only the Kasamene field has identified gas caps.

4.5.3 Estimation of KW Contingent Resources

Kasamene and Wahrindi are fields that will be developed as part of the Phase 1 development project. All resources associated with KW are classified as Contingent Resources (CR).

4.5.3.1 Contingent Resources Development Pending

The KW Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for KW are presented in Table 4-31.

4.5.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-46.

CR DoH Oil	Gross (MMbbls)		
	1C	2C	3C
Phase 1 WF extension	7.4	13.2	13.5
Polymer Flood	5.2	7.1	18.7
Total all oil DoH	**12.6**	**20.4**	**32.3**

Table 4-46 KW Oil DoH Contingent Resource summary

Gas

The solution gas is a by-product of the oil development and has value if a gas development solution is matured. The solution gas recovery associated with the Phase 1 oil project as well as the DoH oil projects been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-47.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	5.3	8.0	12.1
Phase 1 WF extension	1.1	2.0	2.1
Polymer Flood	0.8	1.1	2.9
Total all gas DoH	**7.3**	**11.1**	**17.1**

Table 4-47 KW Gas DoH Contingent Resource summary

4.5.3.3 Contingent Resources Development not Viable

The development of the gas cap in Kasamene is carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

4.5.4 KW CR summary

The total Contingent Resources for the Kasamene-Wahrindi fields are presented in Table 4-48 for oil resources and Table 4-49 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	34.4	52.0	78.5	9.8	14.7	22.2
Development on Hold	12.6	20.4	32.3	3.6	5.8	9.1
Total All CR Categories	**47.1**	**72.3**	**110.8**	**13.3**	**20.5**	**31.4**

Table 4-48 KW Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	7.3	11.1	17.1	2.1	3.2	4.8
Development currently not viable	2.9	5.2	8.3	0.8	1.5	2.4
Total All CR Categories	**10.2**	**16.3**	**25.4**	**2.9**	**4.6**	**7.2**

Table 4-49 KW Gas Contingent Resource summary

4.6 KIGOGOLE FIELD

4.6.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Kigogole**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are variable quality sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field is formed by structural trapping (dip and fault closure) and is heavily faulted.
HCIIP estimate	Oil GIIP P90 – 231 MMstb 26 Bscf P50 – 316 MMstb 36 Bscf P10 – 414 MMstb 48 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	6 E&A wells with 1 side track
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.6.2 Contingent Resources

4.6.2.1 Geoscience review

Kigogole is heavily faulted as shown in Figure 4-45. There are five lithological units. In contrast to other Tilenga Phase 1 fields, H27U is a shale in the Kigogole Field. Hydrocarbons have been encountered in all reservoir intervals drilled to date. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

The stratigraphy and structure of Kigogole are described in Section 4.2.2.1.

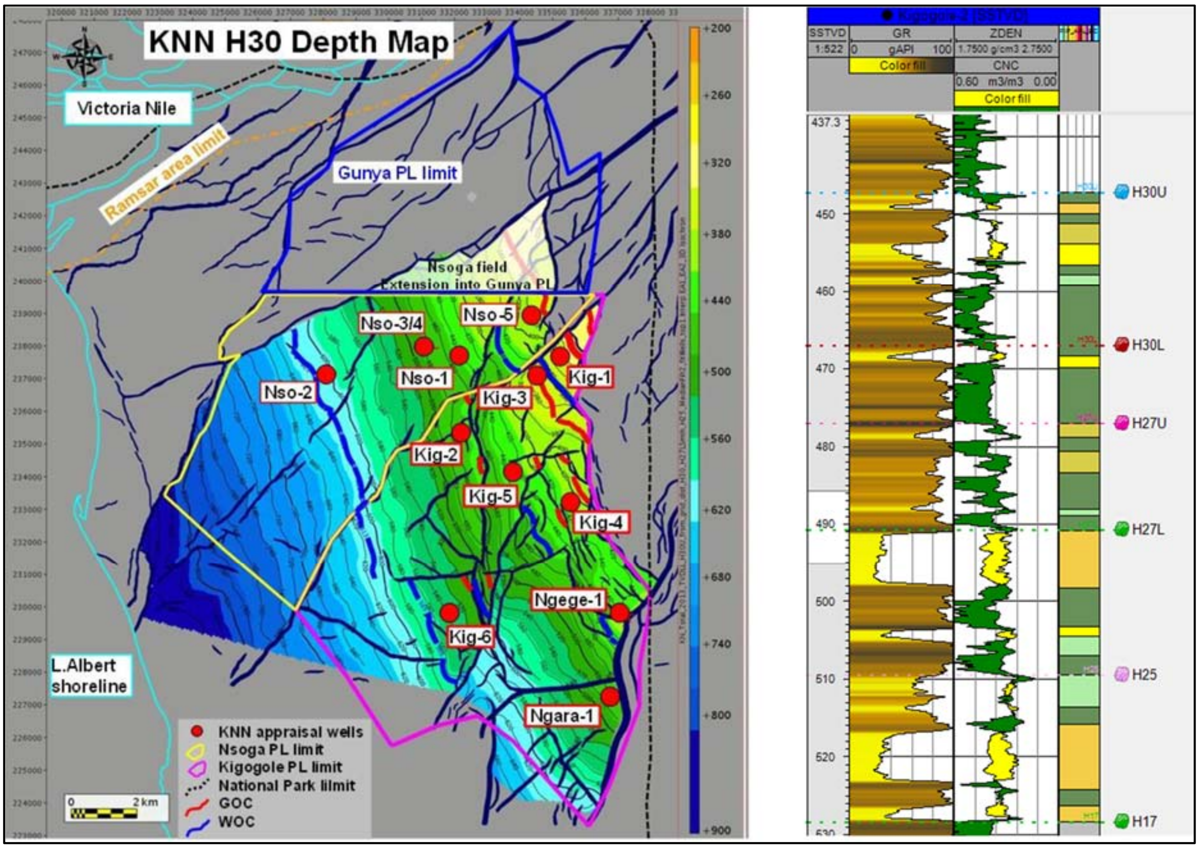


Figure 4-45 Kigogole: Tullow depth map and Kigogole-2 well

TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

The static model follows a similar workflow to that of Jobi-Rii. A key difference is a split in dominant environment of deposition: the northern part of the Kigogole-Nsoga structure is presumed to be a fluvial region whereas the southern part is assigned to the lake region; the boundary varies by zone. The split allows more control during object modelling and more targeted definition of vertical proportion curves.

TRACS has some concerns surrounding the influence radius of the wells in the facies and property modelling, as illustrated for H30L around Kigogole-5 in Figure 4-46. In addition, the porosity modelling in some of the lower net facies appears a little optimistic although the corresponding saturations are low so the impact is likely to be limited.

Again, these apparent inconsistencies have been taken into account when generating the property input for the in place volume estimates.

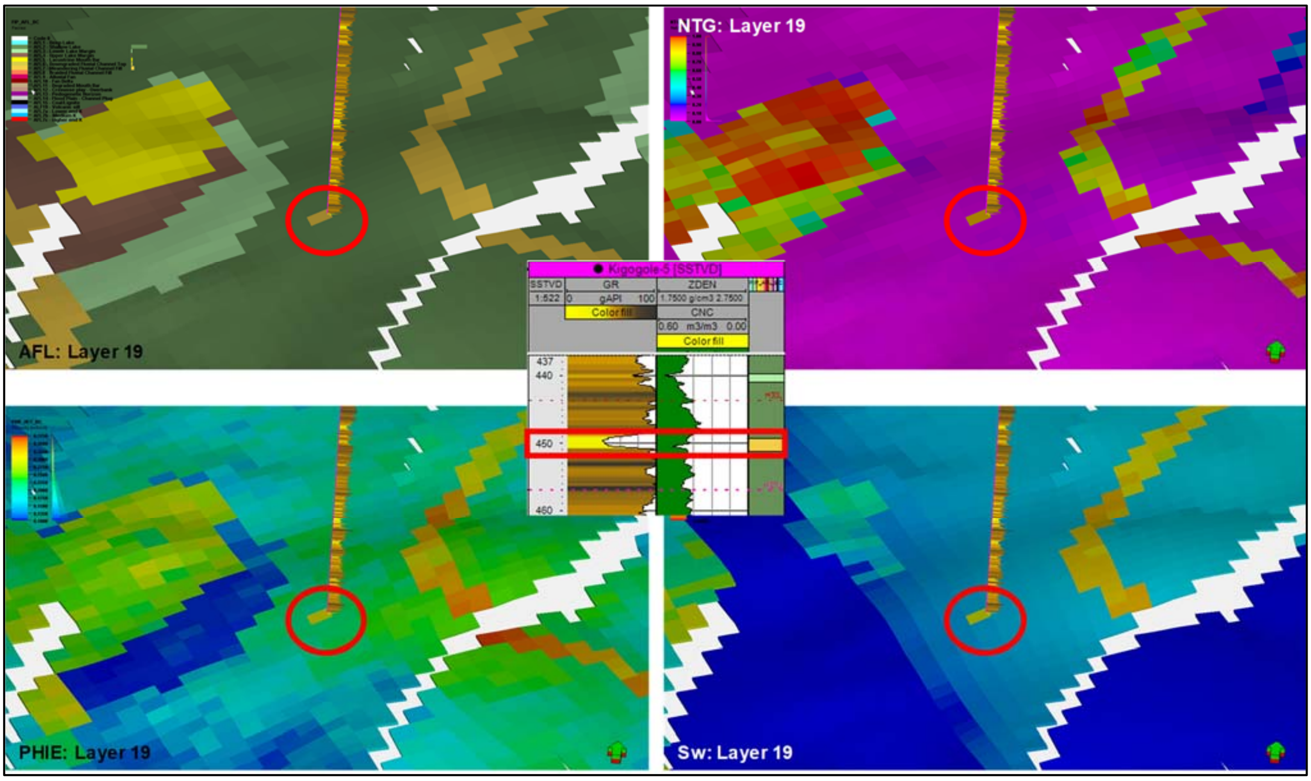


Figure 4-46 Kigogole-5 facies model, NTG, PHIE and Sw (H30L)

4.6.2.2 Petrophysics review

No digital version of the interpretation from logs is available but the individual CPIs are supplied. The measured logs are also supplied and the interpretation appears reasonable so is accepted. Average properties form the wells as included in the PRR are consistent with the well plots and are accepted.

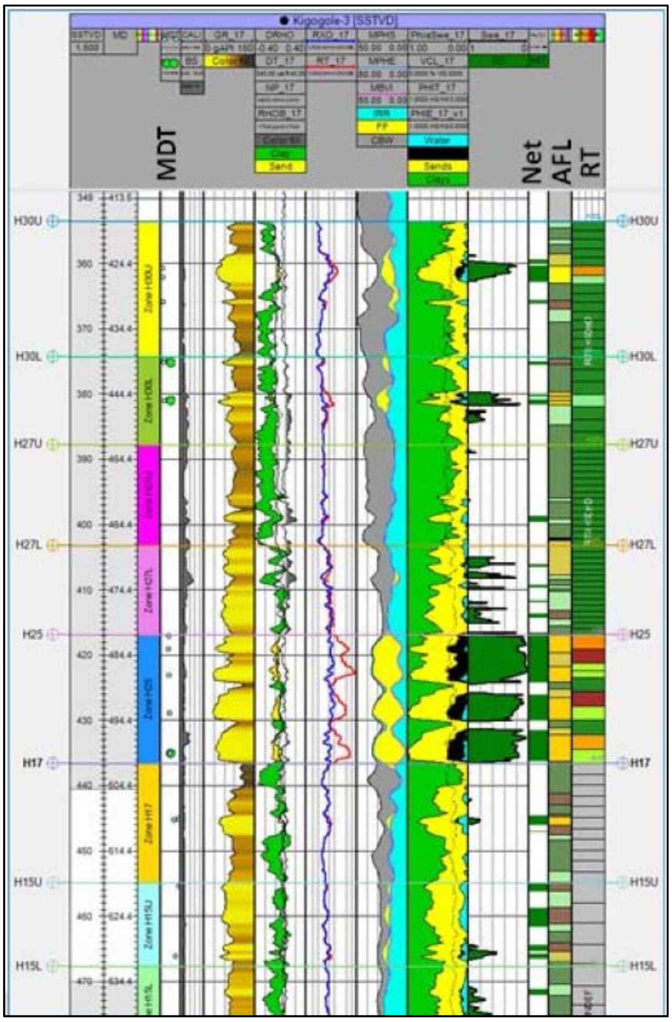


Figure 4-47 From PRR: Kigogole-3 CPI (note shale in H27U)

NTG

As has been the trend throughout, the mid NTG from the model is generally close to the mid average from wells but the range in the model is narrow (Table 4-50). The NTG range has been adjusted where necessary to reflect the variations observed at the wells. H27U has been assigned zero NTG.

	Petrel NTG			NTG Diff			Wells NTG			
	Low	Mid	High	Min	Wt Ave	Max	Min	Wt Ave	Max	
H30U	0.254	0.278	0.290	-0.154	0.000	0.170	0.100	0.278	0.460	H30U
H30L	0.068	0.080	0.116	-0.068	0.000	0.034	0.000	0.080	0.150	H30L
H27U	0.000	0.000	0.000	0.000	0.009	0.050	0.000	0.009	0.050	H27U
H27L	0.299	0.337	0.365	-0.229	-0.038	0.165	0.070	0.299	0.530	H27L
H25U	0.442	0.516	0.485	-0.172	-0.044	0.325	0.270	0.473	0.810	H25U

Table 4-50 Kigogole NTG from wells compared to model

Porosity

The mid modelled porosity is generally higher than the average porosity from wells with a narrow range around the mid value. The range has been adjusted based on the well data in order to capture the range and the uncertainty away from the wells.

	Petrel POROSITY				PHI Diff				Wells POROSITY			
	Low	Mid	High		Min	Wt Ave	Max		Min	Wt Ave	Max	
H30U	0.236	0.237	0.242		-0.066	-0.045	-0.012		0.170	0.192	0.230	H30U
H30L	0.225	0.242	0.246		-0.115	-0.011	0.034		0.110	0.231	0.280	H30L
H27U	0.000	0.000	0.000		0.110	0.110	0.110		0.110	0.110	0.110	H27U
H27L	0.253	0.263	0.248		-0.133	-0.025	0.052		0.120	0.238	0.300	H27L
H25U	0.254	0.269	0.247		-0.104	-0.028	0.013		0.150	0.241	0.260	H25U

Table 4-51 Kigogole Porosity from logs compared to model

Saturation

The So in the PRR for Kigogole includes the water legs and is, therefore, pessimistic. An average So has been taken read from Net Pay on the CPIs and is generally similar to the mid So from the model so these values have been kept almost the same. The range around the mid has been widened.

Contacts

The stacked reservoirs and compartmented nature of the field results in the expected Tilenga picture of complicated fluid distribution (Figure 4-48). No clear fluid contacts are penetrated within any reservoir quality intervals so the fluid up-to and down-to levels are taken as minimums and maximums for the range of possible contacts. Some pressure data is also taken in the oil legs and this is combined with the regional aquifer data to identify possible FWLs.

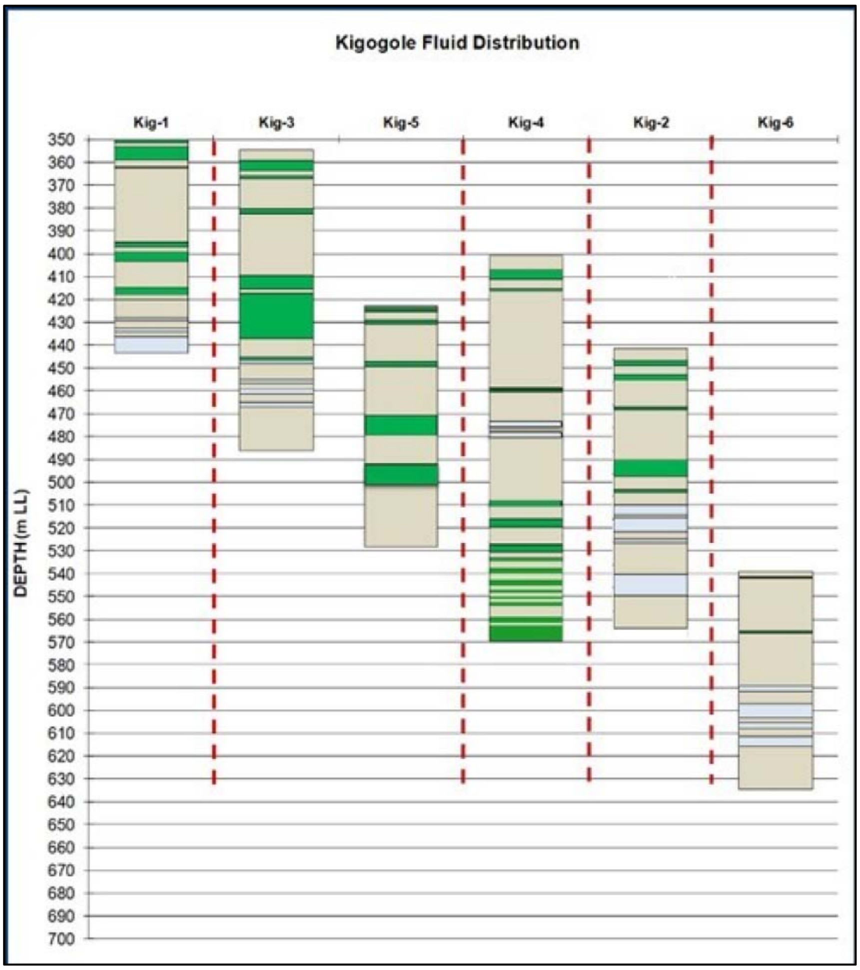


Figure 4-48 From PRR: Kigogole fluids from wells

4.6.2.3 In place volumes

TRACS used the same approach to STOIIP and GIIP assessment as described for Jobi-Rii.

Contacts and GRV

The fluid distribution was reviewed for each pool in order to define Low, Mid and High case contacts. In reservoirs with reliable pressure data these were used to define the Mid case OWC; the uncertainty range is then derived by using different pressure gradient interpretations and/or fluid densities. In reservoirs with no reliable pressure data, ODT and WUT depths were used to define Low and High cases and the average depth was used to define the Mid case.

TRACS implemented numerous contact changes from the Tullow contacts in Kigogole. Some changes are small, others are large, as shown schematically in Figure 4-49for the Low and Mid case. Note this plot captures the Nsoga Field also.

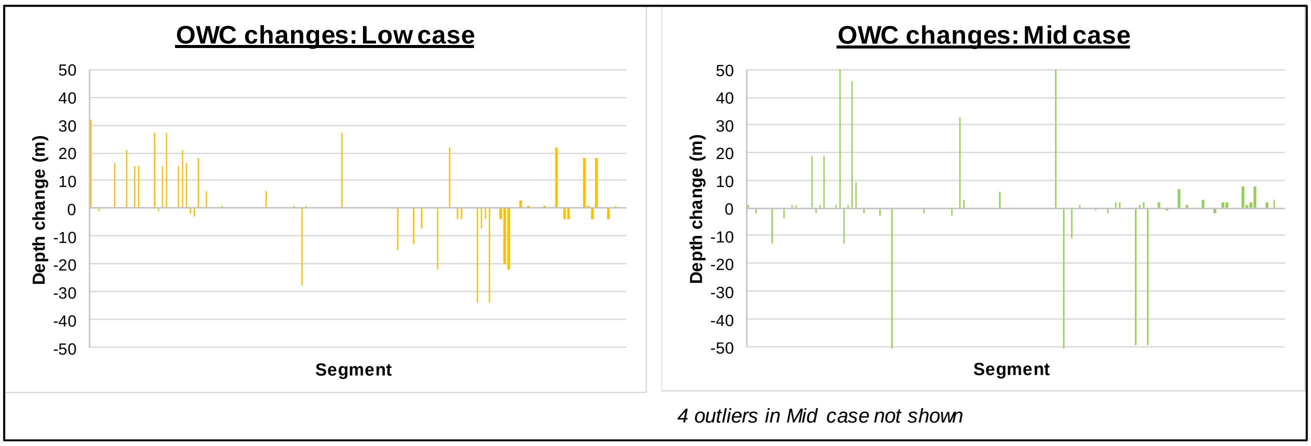


Figure 4-49 Overview of OWC changes in Low and Mid case compared to Tullow estimates

Kigogole has identified small gas caps in some reservoirs. The Tullow gas oil contacts were accepted and used to estimate free gas volumes.

The fluid contacts were applied to the static models to generate updated Low, Mid and High GRV values for use in the TRACS @Risk model. A +/- 10% range was applied to the Low and High GRV cases to account for uncertainty relating to structural interpretation and depth conversion.

Properties

Again, TRACS notes the issues surrounding over-reliance on seismic data to guide facies, NTG and other properties and has opted for a wide range by incorporating well averages. The same approach and methodologies as for previous fields were used to generate the property ranges for the volumetrics.

The oil formation volume factor is taken to have a range from 1.15 to 1.25 with a mid of 1.2 and the gas expansion factor is taken to be a constant 70 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Kigogole field are presented in Table 4-52. An average gas oil ratio of 113 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	**P10**	**P50**	**P90**
STOIIP (MMbbls)	**All reservoirs panels**	**230.6**	**316.4**	**414.1**
GIIP (Bscf)	Solution gas	26.1	35.8	46.8
	Gas cap gas	0.3	0.6	1.1
	Total gas	**26.3**	**36.4**	**47.9**

Table 4-52 TRACS estimate of Kigogole STOIIP and GIIP

4.6.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below. This section addresses the recovery factors for Kigogole and Nsoga developments.

Phase 1 waterflood project

The Kigogole dynamic model provided by Tullow also included the Nsoga Field. As in the Tilenga BoD, the Kigogole and Nsoga fields are treated as a single entity (KN) in terms of dynamic model and production forecast.

The KN full field dynamic simulation model with water injection development was reviewed to generate an understanding of the recovery mechanism for the pattern flood. Some inconsistencies in the STOIIP values used for recovery factors were noted were between the model and PRR. Sweep is complex so the model recovery factor was used for the Mid case, based on full-field STOIIP rather than developed area STOIIP. As in other reservoirs there was a very wide range of recovery factor after 25 and 50 years.

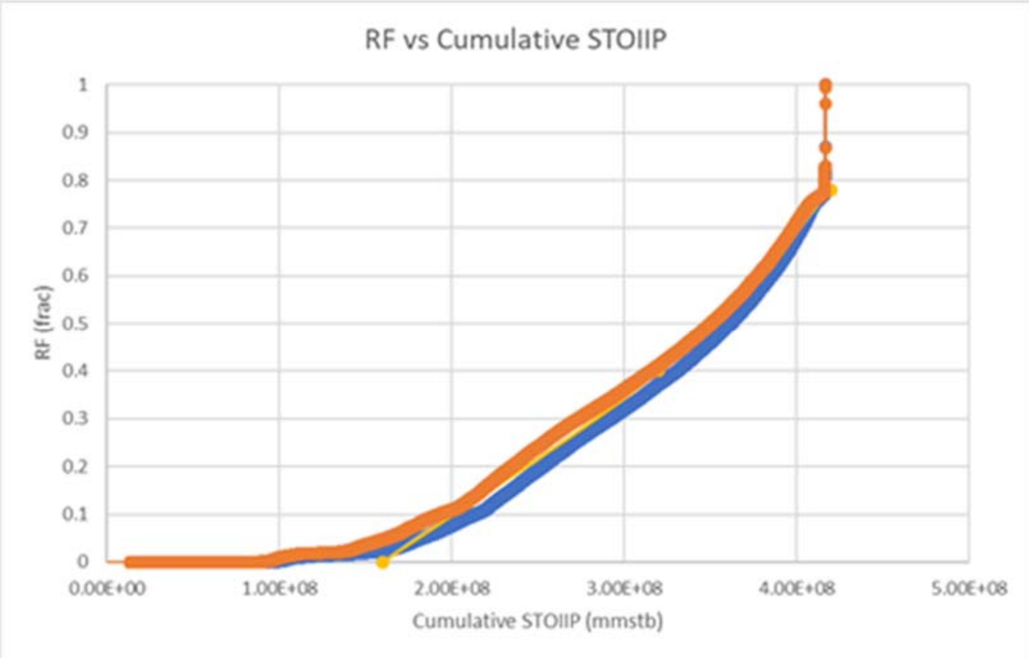


Figure 4-50 Recovery factor in Nsoga region of simulation model vs cumulative STOIIP showing wide range of recovery factors

Low and High case models were provided but were dominated by static uncertainties and, therefore, of little value for estimating the range of uncertainty in recovery factor. Low and High case recovery factors were based on the range of recoveries reported in the uncertainty section of the PRR for relative permeability and Sor (the dominant dynamic uncertainty). These give a range of -15% and +20%. The 50 year recovery factors were estimated using the same water cut increase as in the mid case model (92% to 95%).

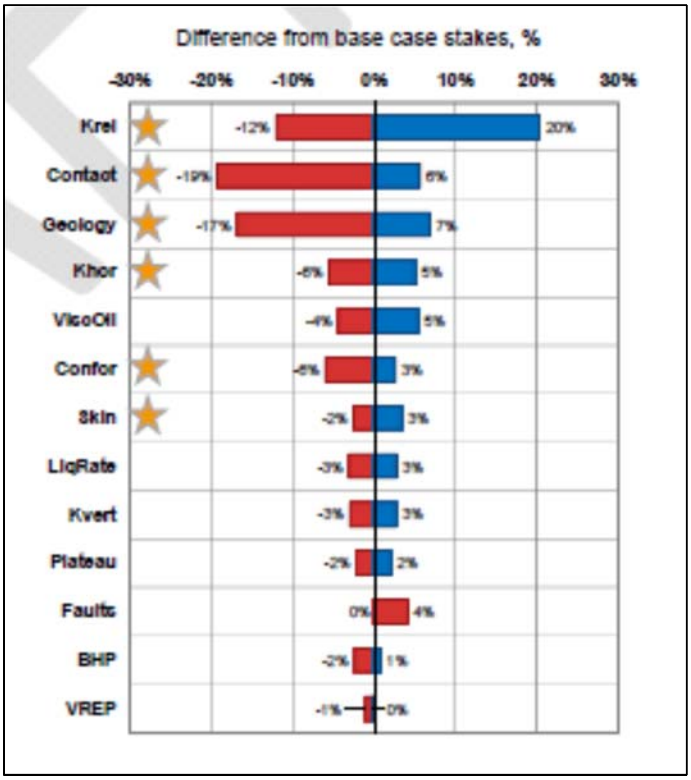


Figure 4-51 KN uncertainties reported in the PRR (note that Krel includes Sor uncertainty)

The resulting range of recovery factors for the Kigogole and Nsoga Phase 1 oil developments are presented in Table 4-53 for 25 and 50 years.

Field	**Project**		**TRACS**	
			25 yrs	50 yrs
Kigogole	Waterflood	L	0.14	0.17
		M	0.17	0.20
		H	0.20	0.24
Nsoga	Waterflood	L	0.16	0.19
		M	0.19	0.22
		H	0.23	0.27

Table 4-53 Kigogole and Nsoga Phase 1 Recovery Factors

The same process as Jobi Rii (see section 4.2.2.4) was used to derive the production forecasts for the Kigogole and Nsoga (KN) fields.

The Mid case simulation model without the Central Processing Facility (CPF) constraints was re-run with 50 years of production forecast. The simulation results were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The oil production wells are constrained by maximum liquid rate of 6 ~ 10 Mblpd, minimum BHP of 450 psia, maximum pressure drawdown of 300 psia, minimum oil rate of 100 bopd and a maximum water cut of 95%.

The maximum water injection rate of a water injectors is 6 ~ 10 Mbwpd. The maximum injection pressure of injection wells varies from 770 to 1050psi, based on the depth of injection intervals. The water injection rate is also controlled by 100% reservoir voidage replacement. These constraints on water injection wells are required to keep the cap rock integrity.

Furthermore, the maximum oil rate of KN block is set at 20 Mbopd, taking account of the field uptime.

The field operating efficiency is 93% and the well operating efficiency is 95%.

The forecasts of oil production profiles were generated from the type curve tool, which combining all Phase 1 fields to meet the constraints of central process facility and pipeline capacity (Figure 3-1).

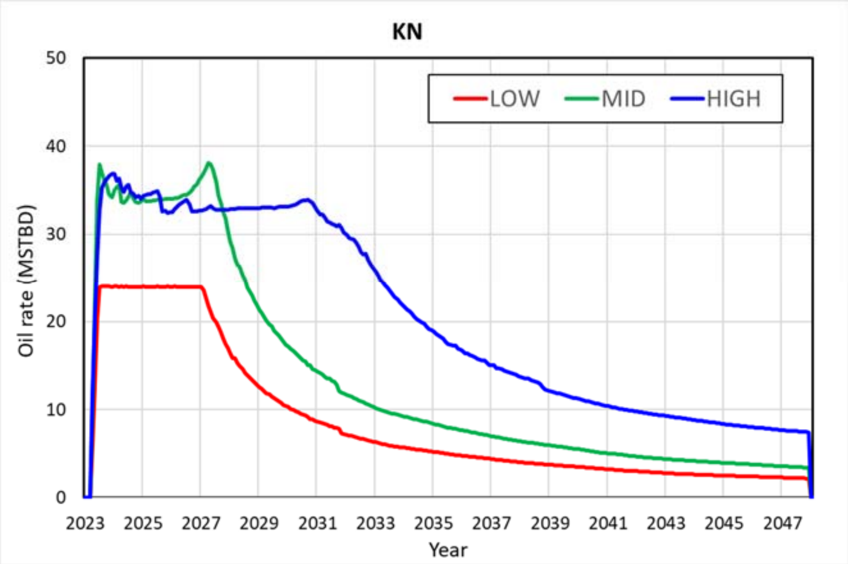


Figure 4-52 Oil production forecast – Kigogole and Nsoga fields

Polymer flood

No models were available for the KN fields and it was concluded that the same polymer flood recovery factors as derived for Wahrindi should be taken for the KN fields. These are presented in Table 4-45

Gas recovery factors

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4).

4.6.3 Estimation of Kigogole Contingent Resources

The Kigogole field will be developed as part of the Phase 1 development project. All resources associated with Kigogole are classified as Contingent Resources (CR).

4.6.3.1 Contingent Resources Development Pending

The Kigogole Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Kigogole are presented in Table 4-31.

4.6.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-54.

CR DoH Oil	**Gross (MMbbls)**		
	1C	**2C**	**3C**
Phase 1 WF extension	6.2	10.4	16.3
Polymer Flood	14.0	23.7	42.5
Total all oil DoH	**20.2**	**34.1**	**58.8**

Table 4-54 Kigogole Oil DoH Contingent Resource summary

Gas

The solution gas recovery associated with the Phase 1 oil project as well as the oil projects have been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-55.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	1.8	3.0	4.6
Phase 1 WF extension	0.4	0.6	0.9
Polymer Flood	0.8	1.3	2.4
Total gas DoH	**3.0**	**4.9**	**7.9**

Table 4-55 Kigogole Gas DoH Contingent Resource summary

4.6.3.3 Contingent Resources Development not Viable

The development of the small gas caps in Kigogole are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

4.6.4 Kigogole CR summary

The total Contingent Resources for the Kigogole field are presented in Table 4-56 for oil resources and Table 4-57 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	32.0	53.4	81.6	9.1	15.1	23.1
Development on Hold	20.2	34.1	58.8	5.7	9.7	16.7
Total All CR Categories	**52.2**	**87.5**	**140.4**	**14.8**	**24.8**	**39.8**

Table 4-56 Kigogole Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	3.0	4.9	7.9	0.8	1.4	2.2
Development currently not viable	0.1	0.4	0.9	0.0	0.1	0.3
Total All CR Categories	**3.1**	**5.4**	**8.8**	**0.9**	**1.5**	**2.5**

Table 4-57 Kigogole Gas Contingent Resource summary

4.7 NSOGA FIELD

4.7.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Nsoga**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are variable quality sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field is formed by structural trapping (dip and fault closure) and is heavily faulted.
HCIIP estimate	Oil GIIP P90 – 282 MMstb 34 Bscf P50 – 355 MMstb 46 Bscf P10 – 443 MMstb 61 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	5 E&A wells with 1 side track
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.7.2 Contingent Resources

4.7.2.1 Geoscience review

Nsoga is heavily faulted as shown in Figure 4-45. There are five lithological units and all contain reservoir, see Figure 4-53.The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools. The stratigraphy and structure of Nsoga are described in Section 4.2.2.1.

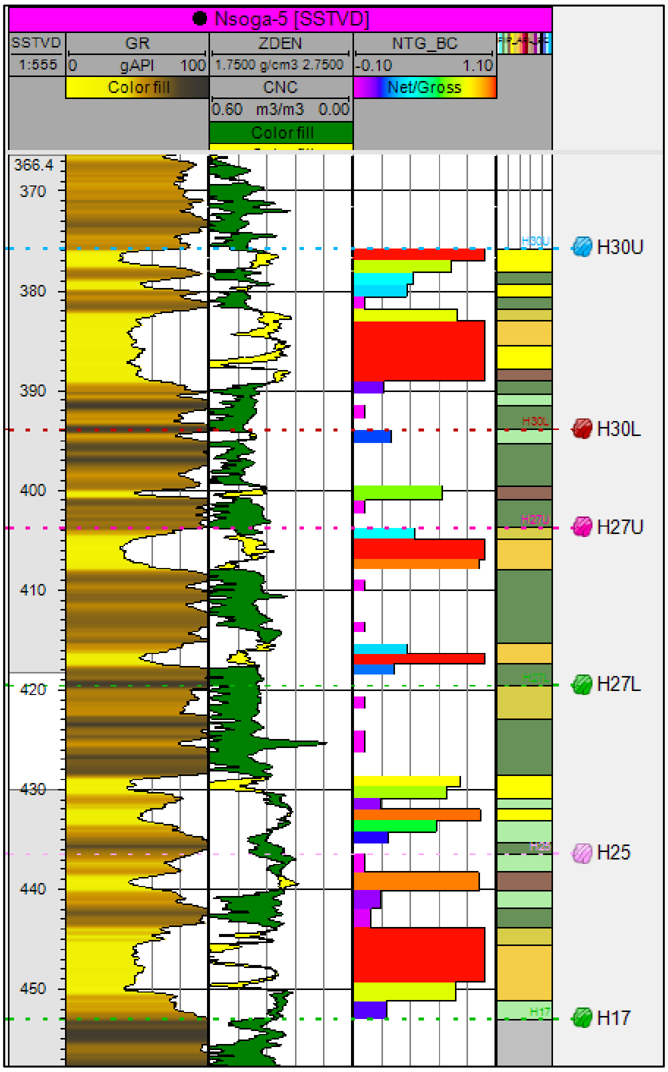


Figure 4-53 Nsoga-5 well

TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

The static model follows the same workflow as that of Kigogole. TRACS reviewed the resulting property grids and associated volumes. TRACS has some concerns surrounding (1) the influence radius of the wells in the facies and property modelling and (2) the porosity modelling in some of the lower net facies. An example is shown in Figure 4-54. A worrying observation is that wells drilled on 3D seismic data often lie on the edge of architectural elements, i.e. the facies/properties improve away from the wells. It is possible that the relationship between seismic attributes and lithology is less robust in the variable quality reservoirs of Kigogole-Nsoga than it is in the fields with better developed sand bodies such as Jobi-Rii and Gunya.

Again, these apparent inconsistencies have been taken into account when generating the property input for the in place volume estimates.

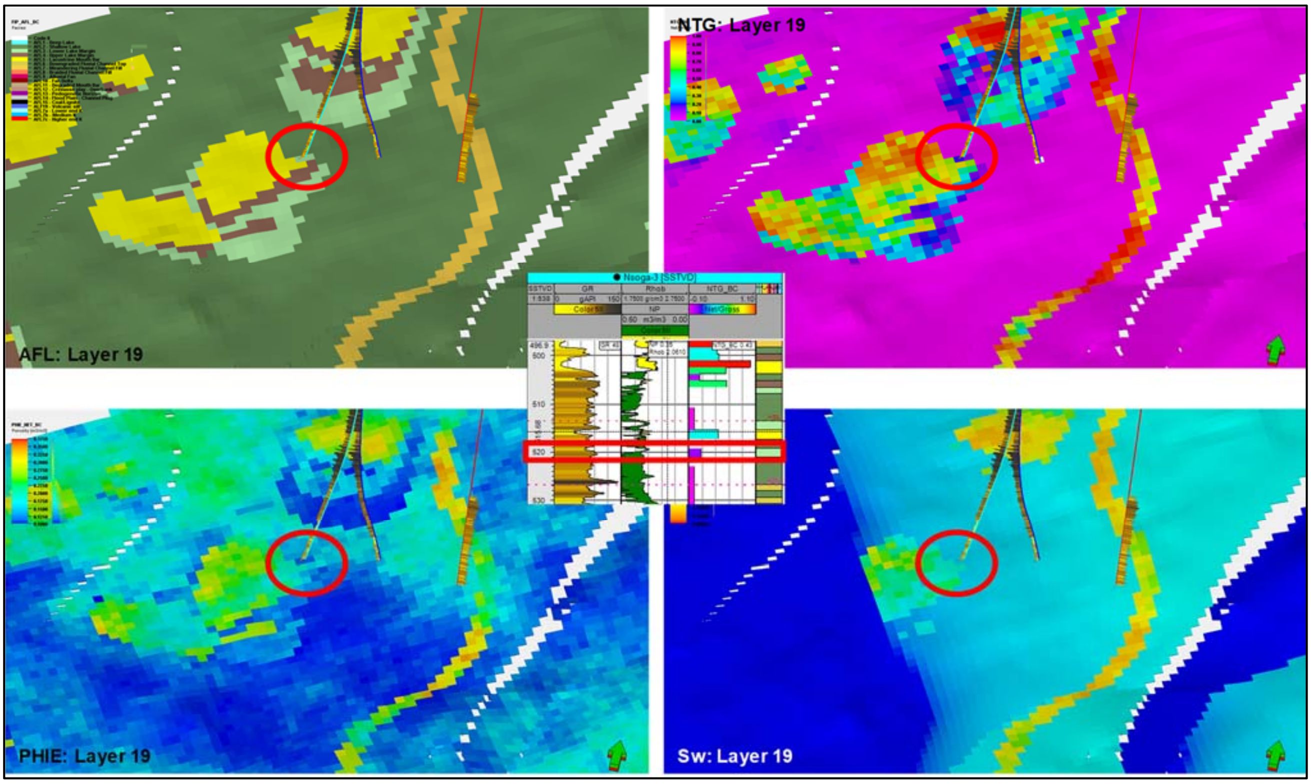


Figure 4-54 Nsoga-3 facies model, NTG, PHIE and Sw (H30L)

4.7.2.2 Petrophysics review

The Nsoga and Kigogole fields are adjacent fields and in some ways they are similar, though there is some reservoir quality sand in the H27U in Nsoga that is absent in Kigogole.

No digital version of the interpretation from logs is available but the individual CPIs are supplied. The measured logs are also supplied and the interpretation appears reasonable so is accepted. Average properties form the wells as included in the PRR are consistent with the well plots and are accepted.

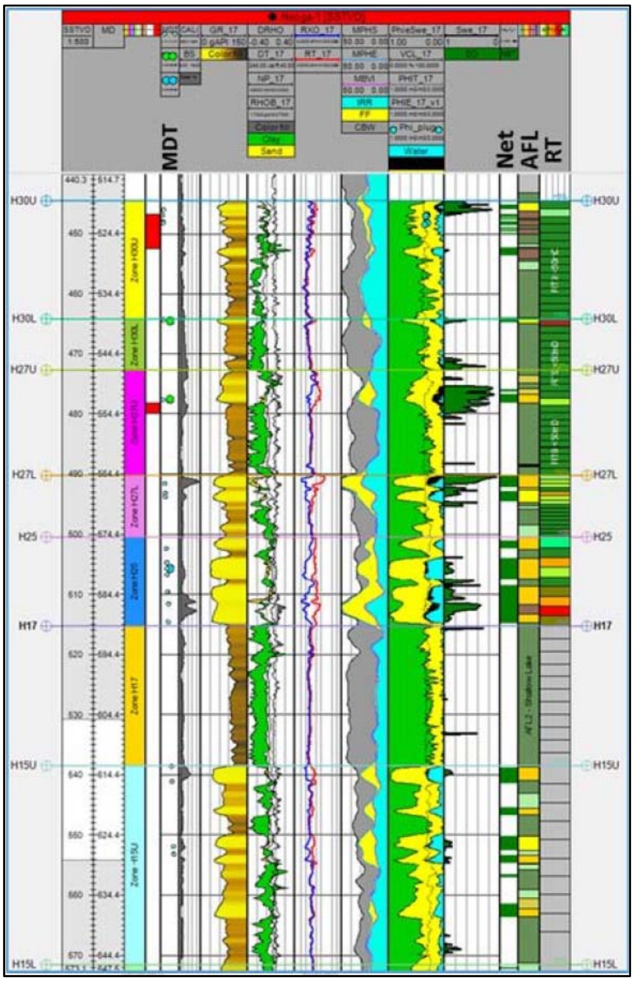


Figure 4-55 From PRR: Nsoga-1 CPI

NTG

The mid NTG from the model is generally close to the mid average from wells but the range in the model is narrow (Table 4-58). The mid NTG has been kept very close to the model value and range has been adjusted where necessary to reflect the variations observed at the wells.

	Model NTG				NTG Diff				Wells NTG			
	Low	Mid	High		Min	Wt Ave	Max		Min	Wt Ave	Max	
H30U	0.310	0.322	0.349		-0.120	0.012	0.201		0.190	0.334	0.550	H30U
H30L	0.108	0.138	0.169		-0.038	-0.001	0.051		0.070	0.137	0.220	H30L
H27U	0.204	0.181	0.216		-0.204	-0.007	0.284		0.000	0.174	0.500	H27U
H27L	0.303	0.362	0.368		-0.073	-0.004	0.282		0.230	0.358	0.650	H27L
H25U	0.480	0.490	0.587		-0.080	0.044	0.153		0.400	0.534	0.740	H25U

Table 4-58 Nsoga NTG from wells compared to model

Porosity

The mid modelled porosity is generally similar to the average porosity from wells with a narrow range around the mid value. The range has been adjusted based on the well data in order to capture the range and the uncertainty away from the wells.

	Model POROSITY				PHI Diff				Wells POROSITY			
	Low	Mid	High		Min	Wt Ave	Max		Min	Wt Ave	Max	
H30U	0.239	0.242	0.244		-0.069	0.009	0.046		0.170	0.251	0.290	H30U
H30L	0.208	0.216	0.241		-0.018	0.024	0.019		0.190	0.241	0.260	H30L
H27U	0.259	0.267	0.270		-0.079	-0.013	0.010		0.180	0.254	0.280	H27U
H27L	0.243	0.261	0.255		-0.033	-0.008	0.035		0.210	0.253	0.290	H27L
H25U	0.259	0.253	0.268		-0.029	-0.002	0.012		0.230	0.250	0.280	H25U

Table 4-59 Nsoga porosity from wells compared to model

Saturation

The So in the PRR for Nsoga includes the water legs and so is pessimistic. An average So has been taken read from Net Pay on the CPIs and is generally similar to the mid So from the model so these values have been kept almost the same. The range around the mid has been widened for some units.

Contacts

The stacked reservoirs and compartmented nature of the field results in the expected Tilenga picture of complicated fluid distribution (Figure 4-56). No clear fluid contacts are penetrated within any reservoir quality intervals so the fluid up-to and down-to levels are taken as minimums and maximums for the range of possible contacts. Some pressure data is also taken in the oil legs and this is combined with the regional aquifer data to identify possible FWLs. The final range is included in the GRV estimation.

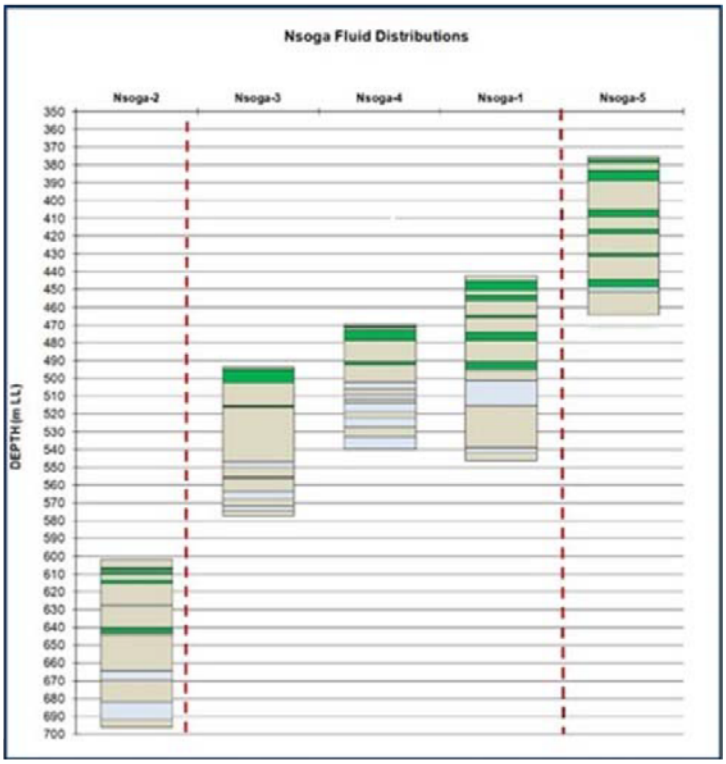


Figure 4-56 From PRR: Nsoga fluids from wells

4.7.2.3 In place volumes

TRACS used the same approach to STOIIP and GIIP assessment as described for Jobi-Rii.

Contacts and GRV

The fluid distribution was reviewed for each pool in order to define Low, Mid and High case contacts. In reservoirs with reliable pressure data these were used to define the Mid case OWC; the uncertainty range is then derived by using different pressure gradient interpretations and/or fluid densities. In reservoirs with no reliable pressure data, ODT and WUT depths were used to define Low and High cases and the average depth was used to define the Mid case.

TRACS implemented numerous contact changes. Some changes are small, others are large, as shown schematically in Figure 4-49 for the Low and Mid case.

Nsoga has identified small gas caps in some reservoirs. The Tullow gas oil contacts were accepted and used to estimate free gas volumes.

The fluid contacts were applied to the static models to generate updated Low, Mid and High GRV values for use in the TRACS @Risk model. A +/- 10% range was applied to the Low and High GRV cases to account for uncertainty relating to structural interpretation and depth conversion.

Properties

The same approach and methodologies as for previous fields were used to generate the property ranges for the volumetrics.

The oil formation volume factor is taken to have a range from 1.15 to 1.25 with a mid of 1.2 and the gas expansion factor is taken to be a constant 70 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Kigogole field are presented in Table 4-60. An average gas oil ratio of 113 scf/bbl has been used to estimate the solution gas volumes.

	Reservoir/ areas	**P10**	**P50**	**P90**
STOIIP (MMbbls)	**All reservoir panels**	**282.1**	**354.9**	**442.9**
GIIP (Bscf)	Solution gas	31.9	40.1	50.0
	Gas cap gas	2.5	6.0	10.8
	Total gas	**34.4**	**46.1**	**60.8**

Table 4-60 TRACS estimate of Nsoga STOIIP and GIIP

4.7.2.4 Analytical approach to CR assessment

The methodology and results of the Nsoga assessment of recovery factors is presented in section 4.6.2.4

4.7.3 Estimation of Nsoga Contingent Resources

The Nsoga field will be developed as part of the Phase 1 development project. All resources associated with Nsoga are classified as Contingent Resources (CR).

4.7.3.1 Contingent Resources Development Pending

The Nsoga Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Nsoga are presented in Table 4-31.

4.7.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-61.

CR DoH Oil	Gross (MMbbls)		
	1C	2C	3C
Phase 1 WF extension	7.6	11.4	17.6
Polymer Flood	11.5	19.9	32.2
Total all oil DoH	**19.2**	**31.2**	**49.8**

Table 4-61 Nsoga Oil DoH Contingent Resource summary

Gas

The solution gas recovery associated with the Phase 1 oil project as well as the oil projects have been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-62.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	2.5	3.8	5.7
Phase 1 WF extension	0.4	0.6	1.0
Polymer Flood	0.7	1.1	1.8
Total gas DoH	**3.6**	**5.5**	**8.5**

Table 4-62 Nsoga Gas DoH Contingent Resource summary

4.7.3.3 Contingent Resources Development not Viable

The development of the small gas caps in Nsoga are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

4.7.4 Nsoga CR summary

The total Contingent Resources for the Nsoga field are presented in Table 4-63for oil resources and Table 4-64 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	44.8	66.9	100.4	12.7	19.0	28.4
Development on Hold	19.2	31.2	49.8	5.4	8.8	14.1
Total All CR Categories	**63.9**	**98.1**	**150.2**	**18.1**	**27.8**	**42.5**

Table 4-63 Nsoga Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	3.6	5.5	8.5	1.0	1.6	2.4
Development currently not viable	1.2	3.9	8.6	0.4	1.1	2.4
Total All CR Categories	**4.9**	**9.5**	**17.1**	**1.4**	**2.7**	**4.8**

Table 4-64 Nsoga Gas Contingent Resource summary

4.8 NGIRI TERRACE FIELD

4.8.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Ngiri Terrace**
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. Ngiri Terrace is the fault panel to the north of the Ngiri Field.
HCIIP estimate	Oil GIIP P90 – 103 MMstb 34 Bscf P50 – 124 MMstb 42 Bscf P10 – 149 MMstb 52 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	1 E&A well
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.8.2 Contingent Resources

4.8.2.1 Geoscience review

Ngiri Terrace lies to the north of the Ngiri Field (Figure 4-29 and Figure 4-57) and is part of the same hydrocarbon system. See Section 4.4.2.1 for more details.

For petrophysics see Section 4.4.2.2

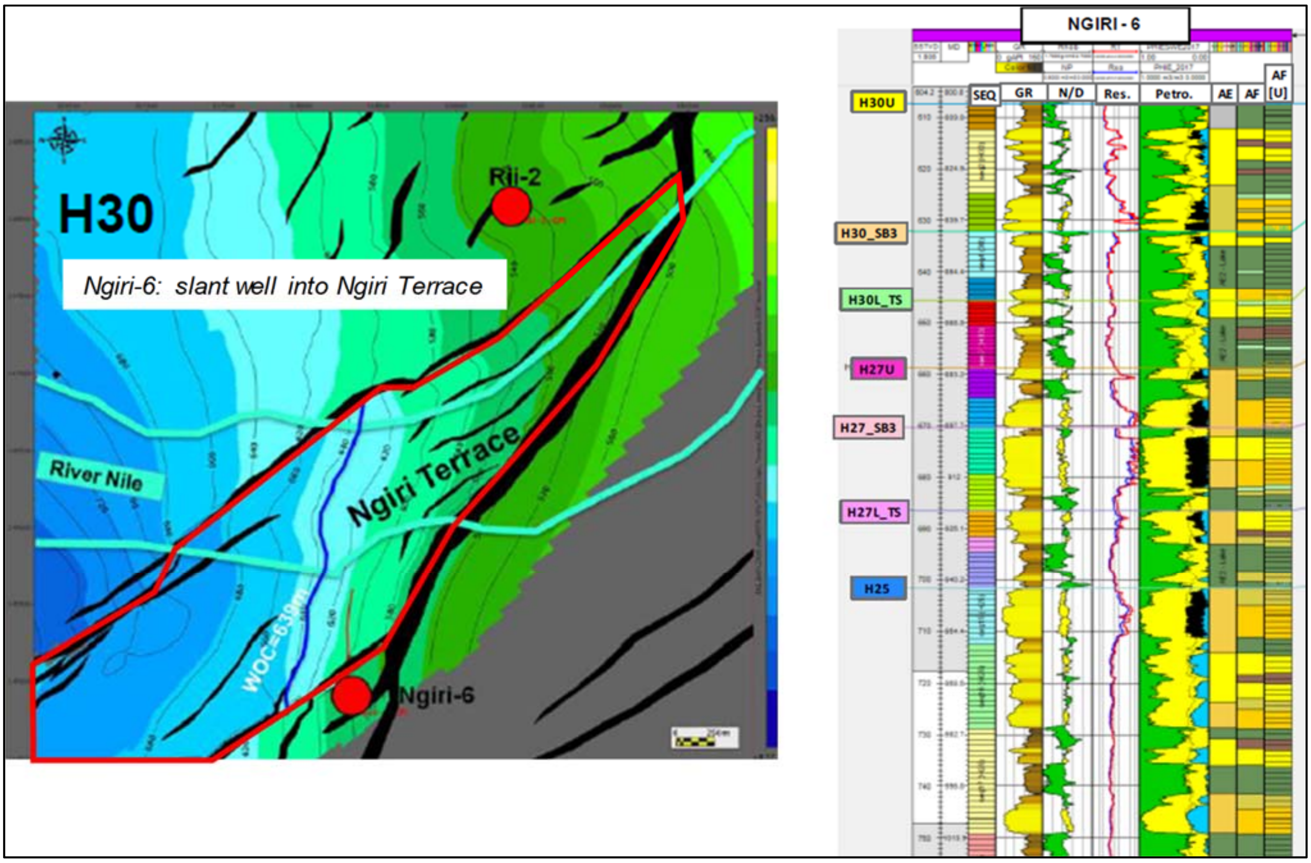


Figure 4-57 Ngiri Terrace: Total depth map and Ngiri-6 well

4.8.2.2 Petrophysics review

Ngiri-6 is the only well in Ngiri terrace. This well been assessed together with the other Ngiri wells. For more information see Section 4.4.2.2

4.8.2.3 In place volumes

The Ngiri Terrace volume estimation follows the methodology of the Jobi Rii assessment.

Contacts and GRV

The fluid contacts for Ngiri Terrace have been derived from the Ngiri-6 well which has good pressure data and is consistent with the aquifer gradient derived with the Ngiri well data. The results for the mid case oil-water contacts are presented in Table 4-65

Depths in mSL	Ngiri Terrace
H30U	640
H30L	
H27U	700
H27L	
H25	711

Table 4-65 Ngiri Terrace: mid case oil-water contacts

Properties

The Ngiri mid reservoir properties were derived from the Ngiri Terrace mid Petrel model and the Ngiri-6 well data. The remaining Ngiri wells together with the low and high Petrel models were used to generate the range of u certainty for the reservoir properties.

The oil formation volume factor is taken to be a constant 1.12 and the gas expansion factor is taken to be a constant 67 v/v.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Ngiri Terrace field are presented in Table 4-66. An average gas oil ratio of 254 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	**All reservoir panels**	**406.9**	**537.1**	**678.8**
GIIP (Bscf)	Solution gas	103.4	136.4	172.4
	Gas cap gas	8.9	13.6	19.2
	Total gas	**112.3**	**150.0**	**191.6**

Table 4-66 Ngiri Terrace Phase 1 Recovery Factors

4.8.2.4 Analytical approach to CR assessment

The analytical approach and range of oil and gas recovery factors for the various Ngiri Terrace projects are the same as presented for Ngiri in section 4.4.2.4. The Phase 1 Ngiri Terrace waterflood project (reservoirs H30+H27+H25) range of recovery factors are presented in Table 4-67.

Field	Project		TRACS	
			25 yrs	**50 yrs**
Ngiri (& Terrace)	WF H30+H27+H25 (Main+Terrace)	L	0.31	0.38
		M	0.36	0.44
		H	0.45	0.55

Table 4-67 Ngiri Terrace Phase 1 Recovery Factors

The Mid case simulation model for Ngiri Terrace without the Central Processing Facility (CPF) constraints was re-run with 50 years of production forecast. The simulation results from Ngiri Terrace Field were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The oil production wells of Ngiri Terrace and Rii-2 fields are constrained by maximum liquid rate of 8 Mblpd and a minimum BHP of 150 psia.

The production wells are also controlled by the ESP operating gas/liquid ratio range, from 35% to 45%. The maximum water injection rate of a water injectors is 9.6 Mbwpd. The maximum injection pressure of injection wells varies from 590 to 930 psia, based on the depth of injection intervals. The water injection rate is also controlled by 100% reservoir voidage replacement. These constraints on water injection wells are required to keep the cap rock integrity.

Furthermore, the maximum oil rate of Ngiri Terrace and Rii-2 fields is set at 70 Mbopd, taking account of the field uptime.

The operating efficiency of Ngiri Terrace and Rii-2 fields is 93% and the operating efficiency of Ngiri Terrace and Rii-2 wells is 95%.

The forecasts of oil production profiles were generated from the type curve tool, which combining all Phase 1 fields to meet the constraints of central process facility and pipeline capacity. The resulting range of profiles for Ngiri Terrace are presented in Figure 4-58.

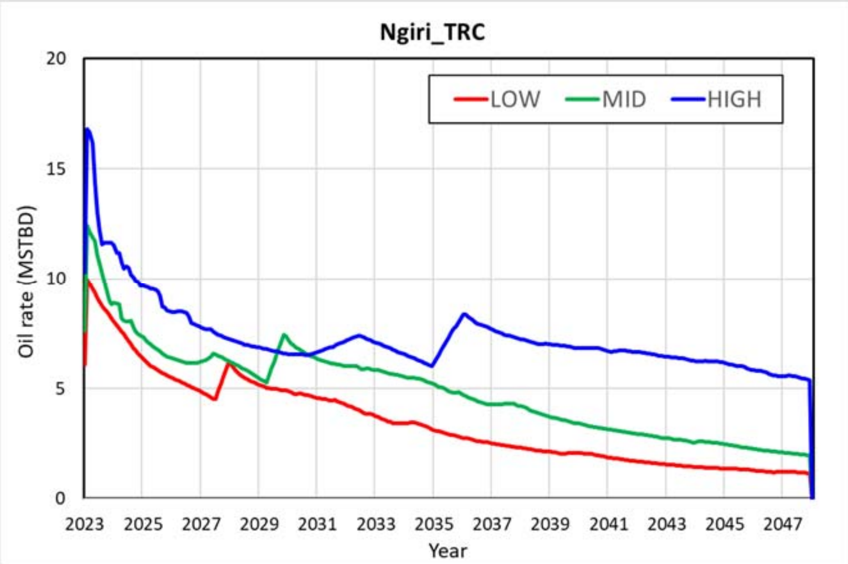


Figure 4-58 Oil production forecast – Ngiri Terrace Field

4.8.3 Estimation of Ngiri Terrace Contingent Resources

Ngiri Terrace is part of the Phase 1 development project. All resources associated with Ngiri Terrace are classified as Contingent Resources (CR).

4.8.3.1 Contingent Resources Development Pending

The Ngiri Terrace Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Ngiri Terrace are presented in Table 4-70. Note that there are no gas DP Contingent Resources as a gas sales solution still needs to be matured.

4.8.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-68.

CR DoH Oil	Gross (MMbbls)		
	1C	2C	3C
Phase 1 WF extension	7.5	10.7	16.9
Polymer Flood	4.0	6.4	9.7
Total all oil DoH	**11.6**	**17.1**	**26.5**

Table 4-68 Ngiri Terrace Oil DoH Contingent Resource summary

Gas

The solution gas is a by-product of the oil development and has value if a gas development solution is matured. The solution gas recovery associated with the Phase 1 oil project as well as the oil projects been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-69.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	4.0	5.6	8.2
Phase 1 WF extension	1.0	1.4	2.1
Polymer Flood	0.5	0.8	1.2
Total all gas DoH	**5.5**	**7.8**	**11.6**

Table 4-69 Ngiri Terrace Gas DoH Contingent Resource summary

4.8.3.3 Contingent Resources Development not Viable

The development of the gas caps in Ngiri Terrace are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

4.8.4 Ngiri Terrace CR summary

The total Contingent Resources for the Ngiri Terrace are presented in Table 4-70 for oil resources and Table 4-71 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	31.4	43.9	64.8	8.9	12.4	18.4
Development on Hold	11.6	17.1	26.5	3.3	4.9	7.5
Total All CR Categories	**43.0**	**61.0**	**91.4**	**12.2**	**17.3**	**25.9**

Table 4-70 Ngiri Terrace Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	5.5	7.8	11.6	1.5	2.2	3.3
Development currently not viable	3.9	7.1	11.1	1.1	2.0	3.1
Total All CR Categories	**9.4**	**14.8**	**22.7**	**2.7**	**4.2**	**6.4**

Table 4-71 Ngiri Terrace Gas Contingent Resource summary

4.9 RII-2 FIELD

4.9.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Rii-2**
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The Rii-2 Field is the fault panel to the south of the Jobi-Rii Field.
HCIIP estimate	Oil GIIP P90 – 58 MMstb 6 Bscf P50 – 96 MMstb 11 Bscf P10 – 146 MMstb 16 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	2 E&A wells
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

4.9.2 Contingent Resources

4.9.2.1 Geoscience review

The Rii-2 Field lies to the south of the Jobi-Rii Field (Figure 4-1). It is disconnected from the main field although there is no conclusive structural separation from Jobi-Rii and Rii-2 is believed to rely on some stratigraphic trapping. See Section 4.4.2.1 for more details.

4.9.2.2 Petrophysics review

The Rii-2 analysis was supplied as figures in the Jobi-Rii PRR. The average properties from Rii-2 are as presented in Table 4-72. Volumes were calculated only for units H30U to H27L since the deeper units are waterbearing. The properties from Jobi-Rii were considered for a regional picture (as described in Jobi-Rii section 4.2.2.2) but the range was defined to reflect the values at Rii-2.

Well	**Interval**	**Net to Gross (%)**	**PHIE Avg (v/v)**
Rii-2	H30U	0.60	0.26
Rii-2	H30L	0.03	0.15
Rii-2	H27U	0.88	0.31
Rii-2	H27L	0.50	0.28

Table 4-72 Average properties for Rii-2

The base case fluid contacts are within 1m of those previously presented by Total.

H30 mid OWC is 545m TVDSL (from logs and pressure data).

H27 mid OWC is 592m TVDSL (from logs, pressure and seismic data).

4.9.2.3 In place volumes

The Rii-2 volume estimation follows the methodology of the Jobi Rii assessment.

The oil formation volume factor is taken to be a constant 1.08. Note that no free gas has been identified in Rii2.

Results

The volumetric input data described above was input into @Risk to generate a range of volumetrics at panel and reservoir level. The panel/reservoir ranges were summed to generate field estimates.

The range of in-place volumes for oil and gas for the Rii2 field are presented in Table 4-73. An average gas oil ratio of 109 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	**P10**	**P50**	**P90**
STOIIP (MMbbls)	**All reservoirs panels**	**406.9**	**537.1**	**678.8**
GIIP (Bscf)	Solution gas	103.4	136.4	172.4
	Gas cap gas	8.9	13.6	19.2
	Total gas	**112.3**	**150.0**	**191.6**

Table 4-73 TRACS estimate of Rii2 STOIIP and GIIP

4.9.2.4 Analytical approach to CR assessment

The analytical approach and range of oil and gas recovery factors for the various Rii2 projects are taken to be the same as presented for Jobi Rii in section 4.2.2.4. The Phase 1 Rii2 flood project (reservoirs H30+H27) range of recovery factors are presented in Table 4-74.

Field	**Project**		**TRACS**	
			25 yrs	**50 yrs**
Rii2	WF Core Area (Main & North)	L	0.14	0.17
		M	0.20	0.25
		H	0.25	0.29

Table 4-74 Rii2 Phase 1 Recovery Factors

The Mid case Rii2 simulation model without the Central Processing Facility (CPF) constraints was re-run with 50 years of production forecast. The simulation results from Rii-2 field were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The same constraints and operating efficiencies were used as for Ngiri Terrace.

The forecasts of oil production profiles were generated from the type curve tool, which combining all Phase 1 fields to meet the constraints of central process facility and pipeline capacity. The resulting range of profiles for Rii2 are presented in Figure 4-59.

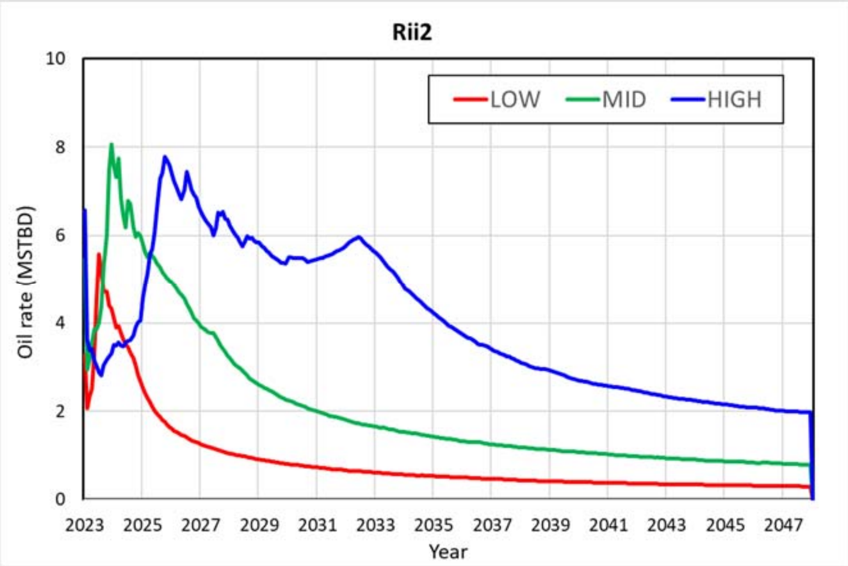


Figure 4-59 Oil production forecast – Rii-2 Field

4.9.3 Estimation of Rii2 Contingent Resources

Rii2 is part of the Phase 1 development project. All resources associated with Rii2 are classified as Contingent Resources (CR).

4.9.3.1 Contingent Resources Development Pending

The Rii2 Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Rii2 are presented in Table 4-77. Note that there are no gas DP Contingent Resources as a gas sales solution still needs to be matured.

4.9.3.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects are summarised below.

- Extension of Phase 1 reservoirs waterflood from licence expiry to 50 years
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 4-75.

CR DoH Oil	Gross (MMbbls)		
	1C	2C	3C
Phase 1 WF extension	1.9	5.1	6.6
Polymer Flood	5.8	10.6	15.5
Total all oil DoH	**7.6**	**15.7**	**22.0**

Table 4-75 Rii2 Oil DoH Contingent Resource summary

Gas

The solution gas is a by-product of the oil development and has value if a gas development solution is matured. The solution gas recovery associated with the Phase 1 oil project as well as the oil projects been classified as DoH. The overview of DoH gas resources by project is presented in Table 4-76.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	0.4	1.0	1.9
Phase 1 WF extension	0.1	0.3	0.4
Polymer Flood	0.3	0.6	0.8
Total all gas DoH	**0.8**	**1.9**	**3.2**

Table 4-76 Rii2 Gas DoH Contingent Resource summary

4.9.3.3 Contingent Resources Development not Viable

There are no resources in this category since Rii2 does not have a gas cap.

4.9.4 Rii2 CR summary

The total Contingent Resources for the Rii2 field are presented in Table 4-77 for oil resources and Table 4-78 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	7.9	18.9	35.8	2.2	5.4	10.1
Development on Hold	7.6	15.7	22.0	2.2	4.4	6.2
Total All CR Categories	**15.5**	**34.6**	**57.8**	**4.4**	**9.8**	**16.4**

Table 4-77 Rii2 Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.8	1.9	3.2	0.2	0.5	0.9
Total All CR Categories	**0.8**	**1.9**	**3.2**	**0.2**	**0.5**	**0.9**

Table 4-78 Rii2 Gas Contingent Resource summary

5 REMAINING TILENGA FIELDS

5.1 OVERVIEW

The remaining Tilenga fields consist of the following fields:

- Ngege
- Ngara
- Jobi East/Lyec
- Mpyo

The fields are located in the EA1 and EA2 licence blocks as shown in Figure 1-1. There are no firm development plans for the fields (they are not part of the Phase 1 development) but they are expected to be candidates for a waterflood development.

This section presents the volumetrics and recoverable resources associated with the fields.

5.2 NGEGE FIELD

5.2.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Ngege**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are Miocene/Pliocene in age deposited in a fluvial/lacustrine deltaic setting and are variable in quality. The field consists of three fault-bound panels in a structural trap (dip and fault closure).
HCIIP estimate	Oil GIIP P90 – 260 MMstb 59 Bscf P50 – 312 MMstb 72 Bscf P10 – 400 MMstb 93 Bscf
Development type	Depletion
Number of current production & injection wells	7 E&A wells with 2 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

5.2.2 Contingent Resources

5.2.2.1 Geoscience review and in place volumes

Introduction

Ngege is divided into three panels, as shown in Figure 5-1, each centred on a well or well set:

- southern: Ngege-1
- western:Ngege-2, 3, 4, 5 and 6
- eastern: Ngege-7

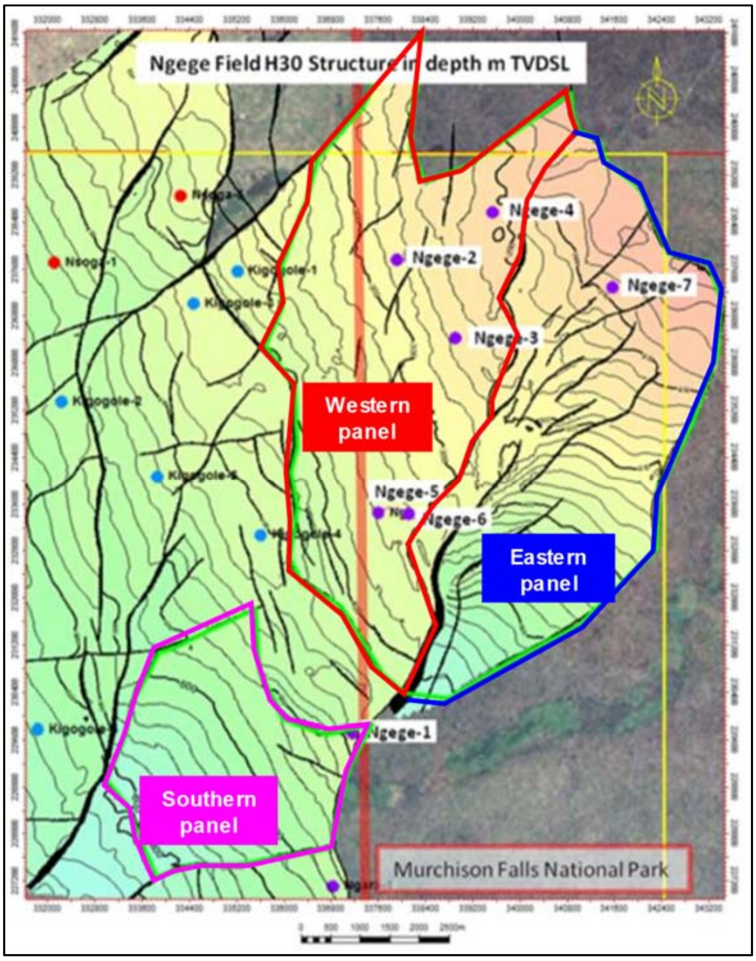


Figure 5-1 Ngege: Tullow depth map

There are four reservoir intervals:

- H15: sand dominated unit of fluvial and alluvial deposits
- H25: significant sand-prone unit, dominated by fluvial deposits
- H27: discontinuous sands and shale
- H30: laminated lacustrine sand-shale sequence with discontinuous fluvial systems
- Hydrocarbons have been encountered in some or all of them, depending on the panel. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

The stratigraphy and structural history of Ngege are similar to those of the Tilenga Phase 1 fields and reference is made to Section 4.2.2.1 for more description. There are, however, some differences, most notably reservoir quality which is poorer and more variable in the eastern part of the Tilenga megastructure.

The petrophysical description is accepted as is.

Tullow did not supply any static or dynamic models of the Ngege Field.

In place volumes

The Ngege Field carries low Contingent Resources and, therefore, was not reviewed in detail. TRACS carried out a high level review of the inputs to Tullow's volumetric assessment and this was accepted.

Results

The range of in-place volumes for oil and gas for the Ngege field are presented in Table 5-1. An average gas oil ratio of 220 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	**All reservoir panels**	**260.2**	**312.0**	**399.8**
GIIP (Bscf)	Solution gas	57.2	68.6	88.0
	Gas cap gas	2.0	2.8	5.4
	Total gas	**59.3**	**71.5**	**93.4**

Table 5-1 TRACS estimate of STOIIP and GIIP

5.2.2.2 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Depletion Phases 1-3

No models were available for Ngege. Recovery factors shown below are consistent with the PRR with full field (rather than developed area) STOIIP with Low representing phase 1 recovery, Mid representing phase 2 recovery and High representing phase 3 recovery. Values appear to be consistent with high viscosity (6-60cp) and low areal sweep efficiency. No further evaluation was performed owing to the small size of the field.

The range of recovery factors for 50 years for Ngege are presented in Table 5-2.

Field	Project		TRACS
			50 yrs RF
Ngege	Depletion phase 1-3	L	0.01
		M	0.03
		H	0.07

Table 5-2 Ngege Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4).

5.2.3 Estimation of Ngege Contingent Resources

5.2.3.1 Contingent Resources Development Pending

No CR Development Pending resources has been identified for Ngege.

5.2.3.2 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Ngege. This has been carried as DoH for oil and (solution) gas. The results are presented in section 5.2.4.

5.2.3.3 *Contingent Resources Development not Viable*

The development of the small gas caps in Ngege are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

5.2.4 Ngege CR summary

The total Contingent Resources for the Ngege field are presented in Table 5-3for oil resources and Table 5-4for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development on Hold	2.6	9.4	28.0	0.7	2.7	7.9
Total All CR Categories	**2.6**	**9.4**	**28.0**	**0.7**	**2.7**	**7.9**

Table 5-3 Ngege Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.3	1.0	3.1	0.1	0.3	0.9
Development not Viable	1.0	1.8	4.4	0.3	0.5	1.2
Total All CR Categories	**1.3**	**2.9**	**7.4**	**0.4**	**0.8**	**2.1**

Table 5-4 Ngege Gas Contingent Resource summary

5.3 NGARA FIELD

5.3.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Ngara**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are Miocene/Pliocene in age deposited in a fluvial/lacustrine deltaic setting and are variable in quality. The field consists of a single fault block located to the south of the Ngege Field.
HCIIP estimate	Oil GIIP P90 – 11 MMstb 2 Bscf P50 – 16 MMstb 3 Bscf P10 – 33 MMstb 6 Bscf
Development type	Depletion
Number of current production & injection wells	1 E&A well
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

5.3.2 Contingent Resources

5.3.2.1 Geoscience review and in place volumes

Introduction

Ngara is a single fault block located to the south of the Ngege Field, see Figure 5-2. The Ngara-1 well found hydrocarbons in the H15 interval which is a sand-dominated zone of fluvial and alluvial deposits.

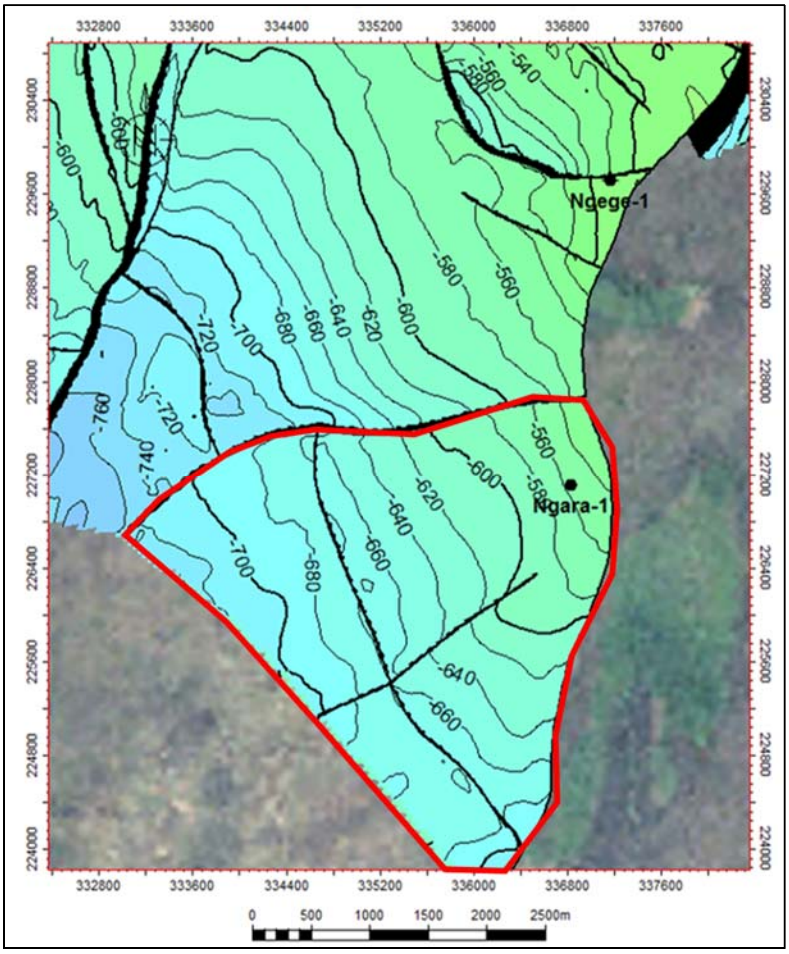


Figure 5-2 Ngara: Tullow depth map

The stratigraphy and structural history of Ngara are similar to those of the Tilenga Phase 1 fields and reference is made to Section 4.2.2.1 for more description. There are, however, some differences, most notably reservoir quality which is poorer and more variable in the eastern part of the Tilenga megastructure.

The petrophysical description is accepted as is.

Tullow did not supply any static or dynamic models of the Ngara Field.

In place volumes

The Ngara Field carries low Contingent Resources and, therefore, was not reviewed in detail. TRACS carried out a high level review of the inputs to Tullow's volumetric assessment and this was accepted.

Results

The range of in-place volumes for oil and gas for the Ngege field are presented in Table 5-5. An average gas oil ratio of 181 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	**Field**	**11.0**	**16.0**	**33.0**
GIIP (Bscf)	Solution gas	2.0	2.9	6.0
	Gas cap gas	0.0	0.0	0.0
	Total gas	**2.0**	**2.9**	**6.0**

Table 5-5 TRACS estimate of STOIIP and GIIP

5.3.2.2 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Depletion project

No data were available for Ngara other than the Tilenga area fields summary table provided by Tullow. Therefore, the Tullow recovery factors have been used and no further analysis has been carried out owing to the small size of the field.

The range of recovery factors for 50 years for Ngara are presented in Table 5-6.

Field	**Project**		**TRACS**
			50 yrs
Ngara	Depletion	L	0.15
		M	0.16
		H	0.12

Table 5-6 Ngara Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4).

5.3.3 Estimation of Ngara Contingent Resources

5.3.3.1 Contingent Resources Development Pending

No CR Development Pending resources has been identified for Ngara.

5.3.3.2 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Ngara. This has been carried as DoH for oil and (solution) gas for Ngara. The results are presented in section 5.3.4.

5.3.3.3 Contingent Resources Development not Viable

There are no resources in this category since Ngara does not have a gas cap.

5.3.4 Ngara CR summary

The total Contingent Resources for the Ngara field are presented in Table 5-7for oil resources and Table 5-8for gas resources.

CR Oil	**Gross (MMbbls)**			**Tullow Working Interest (MMbbls)**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Development on Hold	1.7	2.6	5.6	0.5	0.7	1.6
Total All CR Categories	**1.7**	**2.6**	**5.6**	**0.5**	**0.7**	**1.6**

Table 5-7 Ngara Oil Contingent Resource summary

CR Gas	**Gross (Bscf)**			**Tullow Working Interest (Bscf)**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Development on Hold	0.1	0.2	0.5	0.0	0.1	0.1
Total All CR Categories	**0.1**	**0.2**	**0.5**	**0.0**	**0.1**	**0.1**

Table 5-8 Ngara Gas Contingent Resource summary

5.4 JOBI EAST FIELD / LYEC

5.4.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Jobi East**
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are Miocene/Pliocene in age deposited in a fluvial/lacustrine deltaic setting and are variable in quality. The field consists of a series of (mostly fault-bound) panels in structural, stratigraphic and combination traps. The reservoirs are very shallow and the oil is a viscous fluid. The cut-off depth is 188mGL and corresponds to the shallowest depth for drilling development wells. It also represents the mobile oil limit (Low case).
HCIIP estimate	Oil GIIP P90 – 365 MMstb 22 Bscf P50 – 506 MMstb 30 Bscf P10 – 684 MMstb 41 Bscf
Development type	Water flood development
Number of current production & injection wells	7 E&A wells with 4 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production.

5.4.2 Contingent Resources

5.4.2.1 Geoscience review

Jobi East is divided into six panels (including Lyec). Lyec lies to the north of Jobi East (Figure 5-3) and is part of the same hydrocarbon system. Each panel is centred on a well or well set:

- JE-5/7
- JE-4
- JE-2A
- JE-3
- JE-1/6A
- Lyec

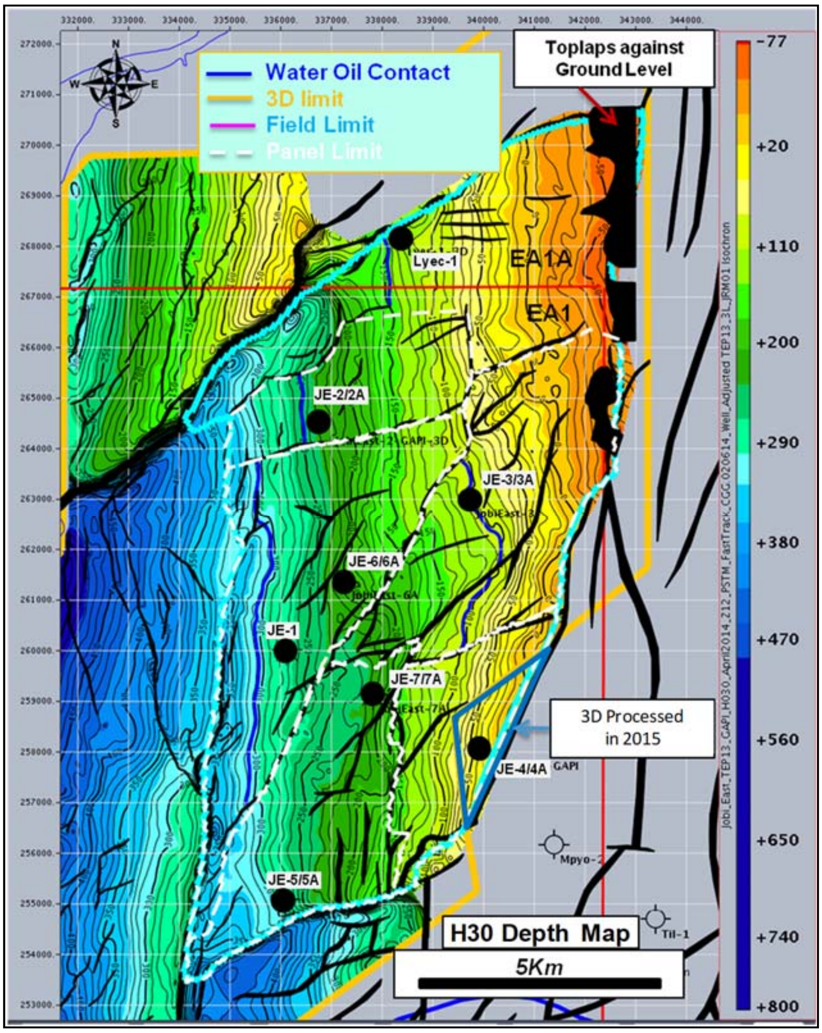


Figure 5-3 Jobi East depth map with panels

There are six reservoir intervals, illustrated in Figure 5-4. Hydrocarbons have been encountered in some or all of them, depending on the panel. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

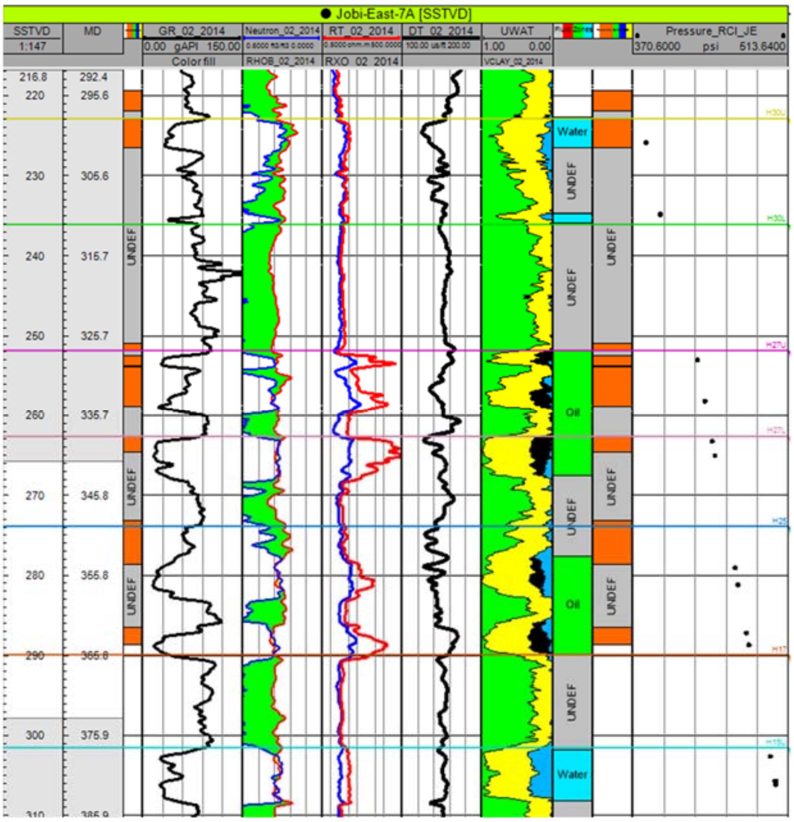


Figure 5-4 Jobi East reservoirs (JE-7A)

The stratigraphy and structural history of Jobi East are similar to those of the Tilenga Phase 1 fields and reference is made to Section 4.2.2.1 for more description. There are, however, some differences, most notably sealing mechanism.

Pay is encountered at very shallow depths but it is unclear how the entire structure is sealed. Nevertheless, a mobile oil limit does exist as there is no oil seen on surface. Tullow has assumed a mobile oil limit at 188mGL which is used in Tullow's Low and Base case STOIIP calculation (High case: 150mGL). This depth also corresponds to the shallowest depth for drilling development wells with 500m horizontal drains. TRACS supports this approach as it is a pragmatic way of dealing with an unresolved issue. While it is clear that in place volumes exist above these cut-off depths, the possibility of accessing them is considered to be small.

TRACS investigated the impact on implied column height with and without the mobile oil limit. In order to do this, 'known' column heights were tabulated where 'known' column height is defined in reservoirs with an observed OWC and a crest below 188m[2]. This is the case only in the JE-7A segment. 'Known' column heights do not exceed 100m. 'Implied' column heights (to crest above 188mGL within segment) become very large, nearly 350m in some cases. Such large columns are difficult to reconcile with the shallow depths under consideration (e.g. crest at 65m). When the mobile oil limit is implemented, the column heights are reduced. Although still larger than 'known' column heights, they are reduced to about 150m.

The mobile oil limit is implemented in Petrel by using a filter that eliminates any rock volume above 188mGL (Low and Base case) or 150mGL (High case). Note, however, that there is an error in the way the filter has been defined in the supplied project. The Low and Base case GRVs use the 150mGL filter instead. TRACS recreated the correct filter and applied it in the GRV calculations.

Another key difference is that Jobi East does not have the well-developed sandstones encountered in Jobi-Rii. Instead the reservoirs intervals consist of fine grained sands interbedded with shales. For instance, the H30 reservoir in JE-3A and JE-4 is characteristic of degraded mouth bar with poor permeability.

TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

[2]Note that the crest is defined only by the highest point within a segment which implies effective fault control.

The static model follows the same workflow as that of Jobi-Rii. TRACS reviewed the resulting property grids and associated volumes. Again, TRACS has some concerns surrounding the weighting of the seismic attributes versus the wells in the facies modelling.

5.4.2.2 Petrophysics review

Jobi East and Lyec fields are on the same structure with a licence boundary dividing them into EA1 and Ea1A. For the purpose of gathering reservoir properties and ranges Jobi East and Lyec have been combined. The compartments and stacked reservoir sequence are consistent with the nearby fields. The interpretation as supplied is supported by core analysis and is accepted.

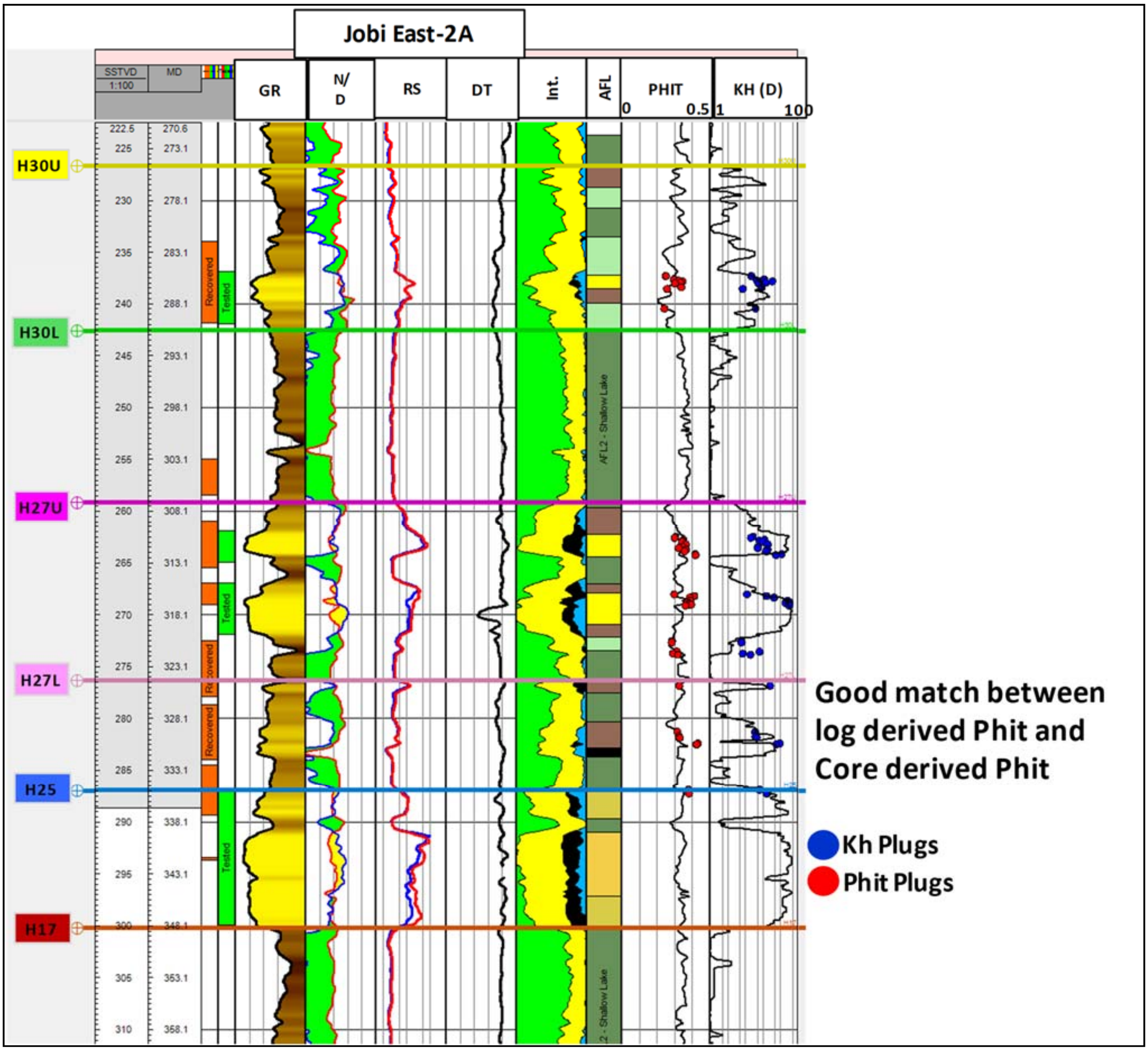


Figure 5-5 Jobi East-2A log analysis/core comparison

NTG

The mid NTG form the model compared to the average from the wells (Table 5-9) are generally similar with H27 (U and L) standing out has having a low mid compared to the wells. The range around the mid is small and these have been expanded to include the range from wells. The updated mid values are generally very close to the Petrel model but they have been increased for the H27 units.

	Jobi East Petrel NTG				NTG Difference			JEL Fieldwide From Wells			
Zones	Low NTG	Base NTG	High NTG		Low Diff	Mid Diff	High Diff	Min NTG	Wt Ave NTG	Max NTG	Zone
H30U	0.25	0.27	0.29		-0.06	0.08	0.28	0.20	0.35	0.56	H30U
H30L	0.03	0.03	0.03		-0.03	-0.01	0.13	0.00	0.03	0.16	H30L
H27U	0.35	0.40	0.44		-0.16	0.16	0.36	0.19	0.56	0.80	H27U
H27L	0.26	0.27	0.28		-0.25	0.14	0.32	0.01	0.41	0.60	H27L
H25	0.49	0.53	0.56		-0.49	0.04	0.33	0.00	0.57	0.89	H25
H17	0.00	0.00	0.00		0.00	0.07	0.25	0.00	0.07	0.25	H17
H15U	0.27	0.29	0.31		-0.24	-0.07	0.03	0.03	0.23	0.34	H15U
H15L	0.00	0.00	0.00		0.00	0.02	0.05	0.00	0.02	0.05	H15L

Table 5-9 Jobi East and Lyec NTG from wells compared to model

Porosity

As has generally been the case, the mid porosity from the model and the average from wells are very similar on the whole but with a narrow porosity range applied in the model. For Jobi East and Lyec the mid porosity in H30L is lower than the average from the wells by 8pu (Table 5-10). For the volumes the mid for H30L has been increased to 16% and the range has been widened for all units.

	Jobi East Petrel Porosity				Porosity Diference			JEL Fieldwide from Wells			
Zones	Low Porosity	Base Porosity	High Porosity		Low Diff	Mid Diff	High Diff	Min PHIE	Wt Ave PHIE	Max PHIE	Zone
H30U	0.18	0.18	0.19		-0.01	0.03	0.06	0.17	0.21	0.25	H30U
H30L	0.12	0.12	0.11		0.05	0.08	0.09	0.17	0.20	0.20	H30L
H27U	0.25	0.25	0.26		-0.03	0.02	0.06	0.22	0.28	0.32	H27U
H27L	0.24	0.25	0.25		-0.10	0.00	0.06	0.15	0.24	0.31	H27L
H25	0.26	0.27	0.27		-0.03	-0.01	0.05	0.23	0.26	0.31	H25
H17	0.00	0.00	0.00		0.17	0.22	0.33	0.17	0.22	0.33	H17
H15U	0.24	0.25	0.25		-0.11	0.01	0.07	0.13	0.25	0.32	H15U
H15L	0.00	0.00	0.00		0.12	0.19	0.23	0.12	0.19	0.23	H15L

Table 5-10 Jobi East and Lyec Porosity from wells compared to model

Saturation

So from the model is generally higher than the average So from logs. As has been described So in the model is calculated from Saturation height functions as described in Jobi-Rii section. The modelled So is included in the range for volumes but the range is widened.

	Jobi East Petrel So				So Difference			JEL Fieldwide From Wells			
Zones	Low So (oil leg only)	Base So (oil leg only)	High So (oil leg only)		Low Diff	Mid Diff	High Diff	So	Wt Ave So	Max So	Zone
H30U	0.64	0.65	0.66		-0.42	-0.11	-0.01	0.21	0.54	0.65	H30U
H30L	0.51	0.51	0.51		-0.51	-0.51	-0.51	0.00		0.00	H30L
H27U	0.74	0.74	0.75		-0.29	-0.15	-0.03	0.45	0.60	0.73	H27U
H27L	0.75	0.75	0.75		-0.53	-0.13	-0.05	0.22	0.62	0.71	H27L
H25	0.76	0.76	0.77		-0.24	-0.17	0.04	0.52	0.59	0.81	H25
H17	0.00	0.00	0.00		0.20	0.23	0.24	0.20	0.23	0.24	H17
H15U	0.73	0.73	0.73		-0.48	-0.12	-0.09	0.24	0.61	0.64	H15U
H15L	0.00	0.00	0.00		0.00	0.00	0.00	0.00		0.00	H15L

Table 5-11 Jobi East and Lyec Oil Saturation from wells compared to model

Contacts

Jobi East and Lyec contacts have been reviewed including the logs and pressure data and the ranges for most reservoir units is aligned with the contacts in the Total model. The fluid distribution from logs illustrates the contacts vary over different segments.

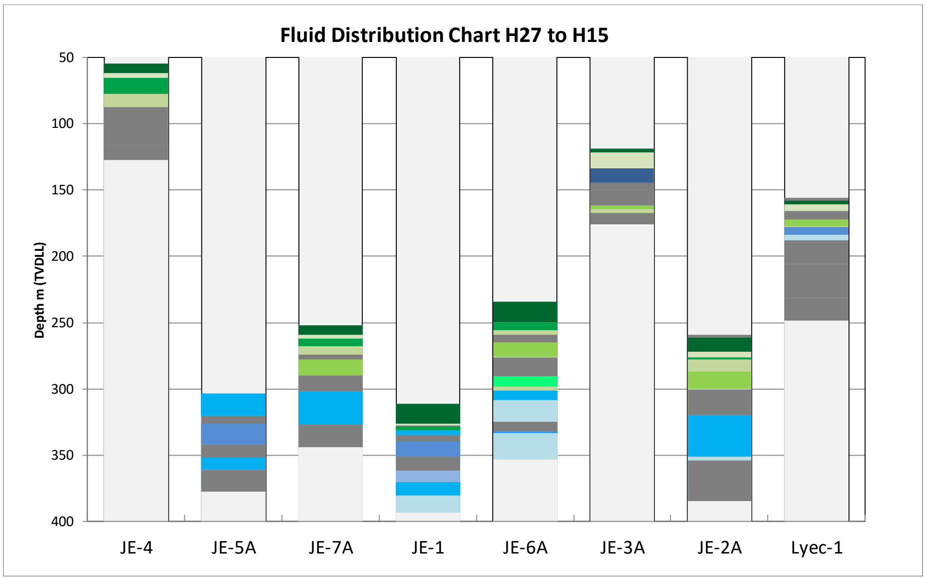


Table 5-12 Jobi East and Lyec fluid distribution from logs

5.4.2.3 In place volumes

GRV

TRACS has adopted the same mobile oil limit by using the appropriate (and correctly defined) filters in the Low, Mid and High cases.

The contact ranges were reviewed and updates were made, some of which are significant, for instance in the JE-2 segment. H30 contacts are based on ODT from logs (Min), base of map (Max) with the Mid taken as the average. H27 and H25 contacts are centred on the FWL from pressures ±10m.Table 5-13 shows the TRACS contact ranges for the JE-2 segment; entries in grey are within 40m of Total's contacts.

Depths in mLL	**TRACS**		
	Min	**ML**	**Max**
H30U	239	289.5	340
H30L	239	289.5	340
H27U	332	342	352
H27L	332	342	352
H25	332	342	352

Table 5-13 Jobi East: JE-2 segment contact range

The calculated Min-ML-Max GRVs for each zone and segment were input into @Risk as P90-P50-P10 to allow for additional structural uncertainty, e.g. related to depth and thickness uncertainty.

No volumes are assigned to segment JE-2A North (no well).

Properties

The properties in the models are directly related to the facies models generated by Total. The facies modelling workflow uses Architectural Elements (AEs) based on seismic attributes to define the large scale depositional environment and heterogeneity. The petrophysical properties are then distributed within this three dimensional facies framework. Insofar as is possible, TRACS has reviewed the AEs against seismic attribute extractions and compared to well data (Figure 5-7).

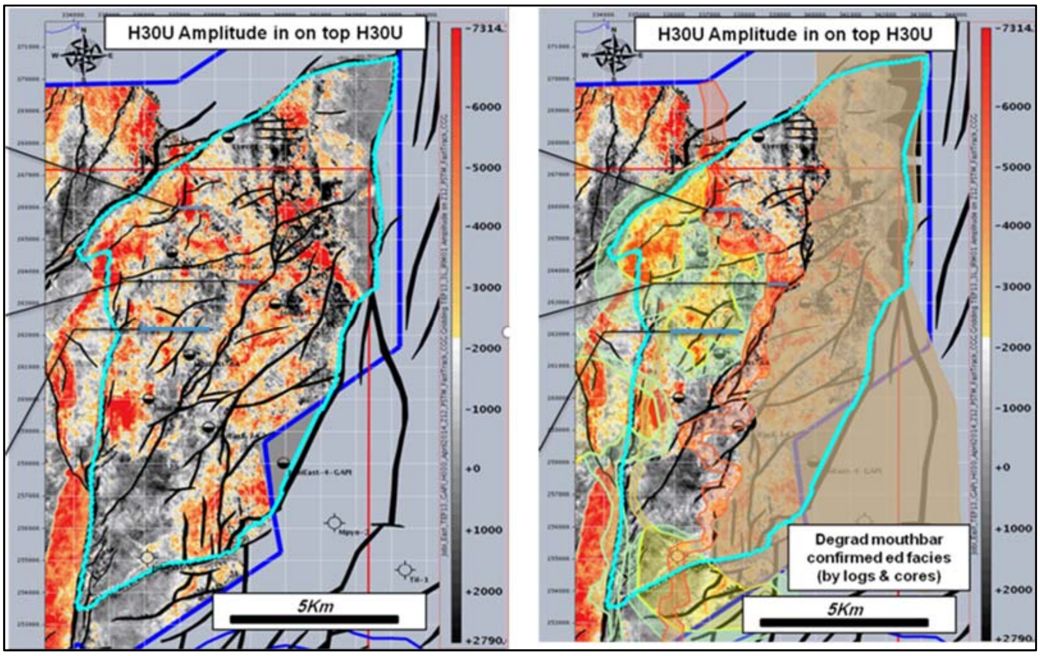


Figure 5-6 Jobi East: H30U attribute map and AE interpretation

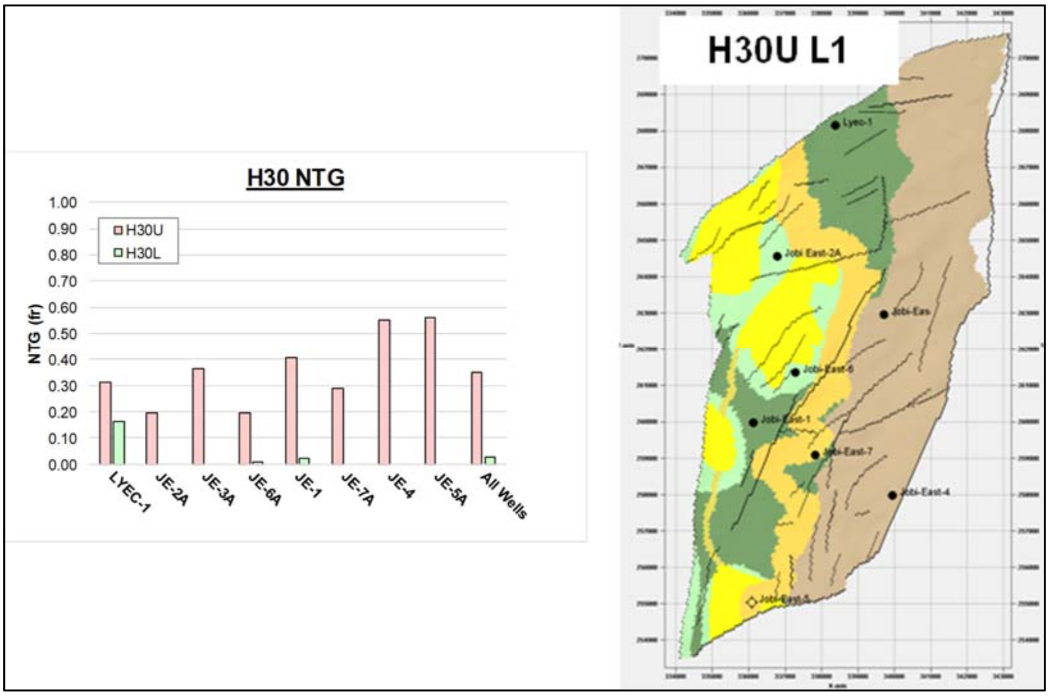


Figure 5-7 Jobi East: H30U NTG in wells and AE interpretation

The definition of the AEs looks reasonable and represents one valid realisation of AE distribution. The resulting facies model supports a better developed sand system in the West and sets up vertical connectivity at the H25-H2 level. In block JE-1/6A connectivity remains uncertain. There is of course a lot of detail beyond seismic resolution that could throw up surprises relating to NTG distribution, lateral compartmentalisation within a segment and possibly vertical compartmentalisation. The key message is that well averages of NTG might not be indicative of 3D averages.

All properties from the Petrel facies models were reviewed and compared to well data. The same approach and methodologies as for previous fields (see Section 4.2.2.3were used to generate the property ranges for the volumetrics.

All parameters were input as Min-ML-Max in a triangular distribution.

The oil formation volume factor is taken to be 1.05 for all zones and segments. Jobi East has no gas cap.

Results

The range of in-place volumes for oil and gas for Jobi East is shown in Table 5-14 and the split by panel shown in Table 5-15. It is clear that segment JE-1/6 is the greatest contributor in terms of in place volumes. An average gas oil ratio of 60 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	**P10**	**P50**	**P90**
STOIIP (MMbbls)	**All reservoirs panels**	**365.1**	**506.4**	**684.4**
GIIP (Bscf)	Solution gas	21.9	30.4	41.1
	Total gas	**21.9**	**30.4**	**41.1**

Table 5-14 Jobi East/Lyec STOIIP and GIIP range

STOIIP (MMstb)	**P90**	**P50**	**P10**
JE-2 segment	79.4	111	152
JE-1/6 segment	193	266	354
JE-5/7 segment	91.6	125	166
JE-3 segment	0.3	1.5	3.6
JE-4 segment	0.3	1.7	4.3
Lyec	0.3	1.5	3.7
Total	**365.1**	**506.4**	**684.4**

Table 5-15 Jobi East STOIIP split by panel

No Free GIIP is reported for Jobi East.

5.4.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Waterflood core area

No models were available for Jobi East and the recovery factors are based on the only information seen: a 2014 workshop summary in PowerPoint format.

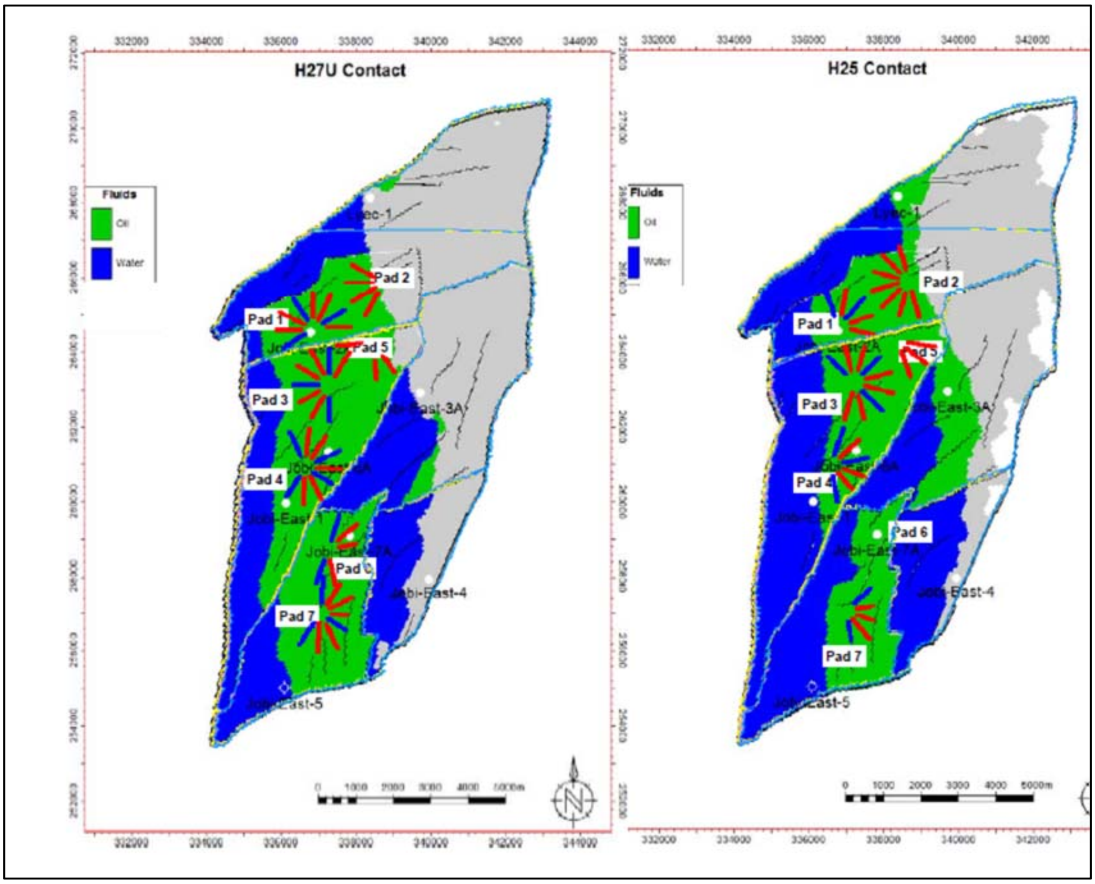


Figure 5-8 Jobi East full field development pattern

Recovery focuses on H27U, H27L and H25 in 3 panels (JE2A, JE1/6 and JE5/7) – described as the core area with approximately 550mmstb STOIIP. Phased development of very high viscosity (200-500cp) reservoirs using pattern floods is reported to have recovery factors ranging from 4-10%. In the absence of other data, these values have been used to estimate resources. The workshop summary shows evidence that these values are backed up by modelling and a good quality uncertainty study using experimental design.

The range of recovery factors for 50 years for Jobi East are presented in Table 5-16.

Field	**Project**		**TRACS**
			RF at 50 yrs
Jobi East	WF core area	L	0.04
		M	0.08
		H	0.10

Table 5-16 Jobi East Phase 1 Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

5.4.3 Estimation of Jobi East Contingent Resources

5.4.3.1 Contingent Resources Development Pending

No CR Development Pending resources has been identified for Jobi East.

5.4.3.2 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Jobi East. This has been carried as DoH for oil and (solution) gas. The results are presented in Section 5.4.4.

5.4.3.3 Contingent Resources Development not Viable

There are no resources in this category since Jobi East does not have a gas cap.

5.4.4 Jobi East CR summary

The total Contingent Resources for the Jobi East field are presented in Table 5-17 for oil resources and Table 5-18for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development on Hold	14.6	40.4	68.1	4.1	11.4	19.3
Total All CR Categories	**14.6**	**40.4**	**68.1**	**4.1**	**11.4**	**19.3**

Table 5-17 Jobi East Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.4	1.2	2.0	0.1	0.3	0.6
Total All CR Categories	**0.4**	**1.2**	**2.0**	**0.1**	**0.3**	**0.6**

Table 5-18 Jobi East Gas Contingent Resource summary

5.5 MPYO FIELD

5.5.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Mpyo**
Location	Albert Basin Area EA-1
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Total
Geology	The reservoirs are Miocene/Pliocene in age deposited in a fluvial/lacustrine deltaic setting and are variable in quality. The field consists of a series of(mostly fault-bound) panels in structural, stratigraphic and combination traps.
HCIIP estimate	Oil GIIP P90 – 214 MMstb 11 Bscf P50 – 324 MMstb 16 Bscf P10 – 455 MMstb 22 Bscf
Development type	Water flood development
Number of current production & injection wells	8 E&A wells with 2 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production.

5.5.2 Contingent Resources

5.5.2.1 Geoscience review

Mpyo is divided into nine panels, as shown in Figure 5-9, each centred on a well or well set:

- Mpyo-1
- Mpyo-2 (water bearing)
- Mpyo-3
- Mpyo-4A
- Mpyo-5A
- Mpyo-6
- Mpyo-7
- Central North
- Til

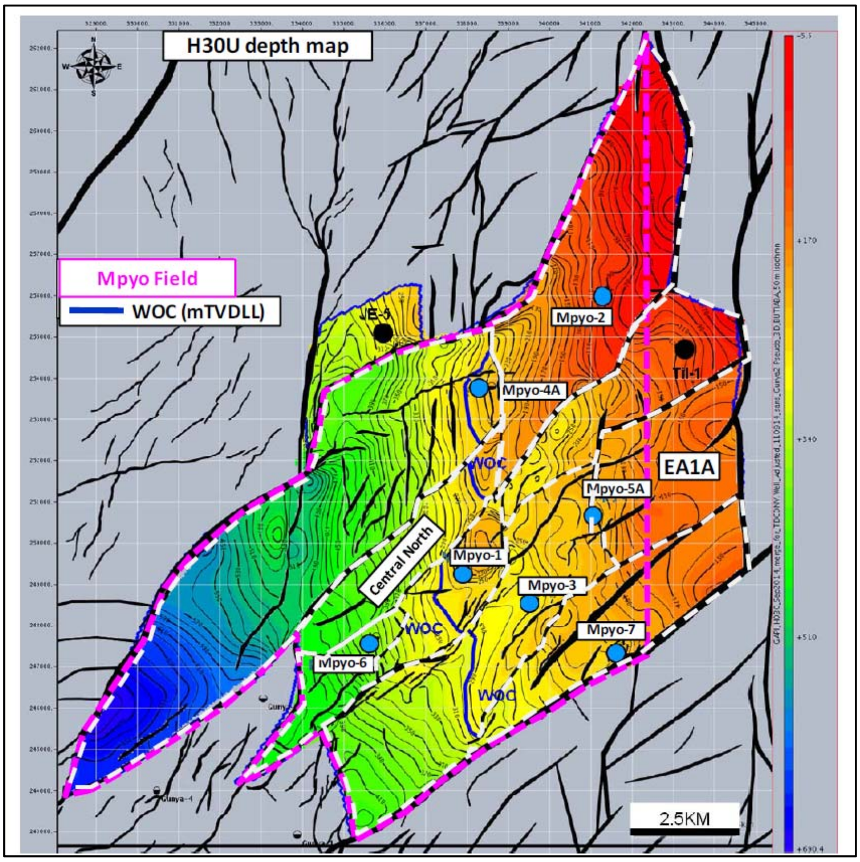


Figure 5-9 Mpyo: Total depth map with segments

There are five reservoir intervals, illustrated in Figure 5-10. Hydrocarbons have been encountered in some or all of them, depending on the panel. The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

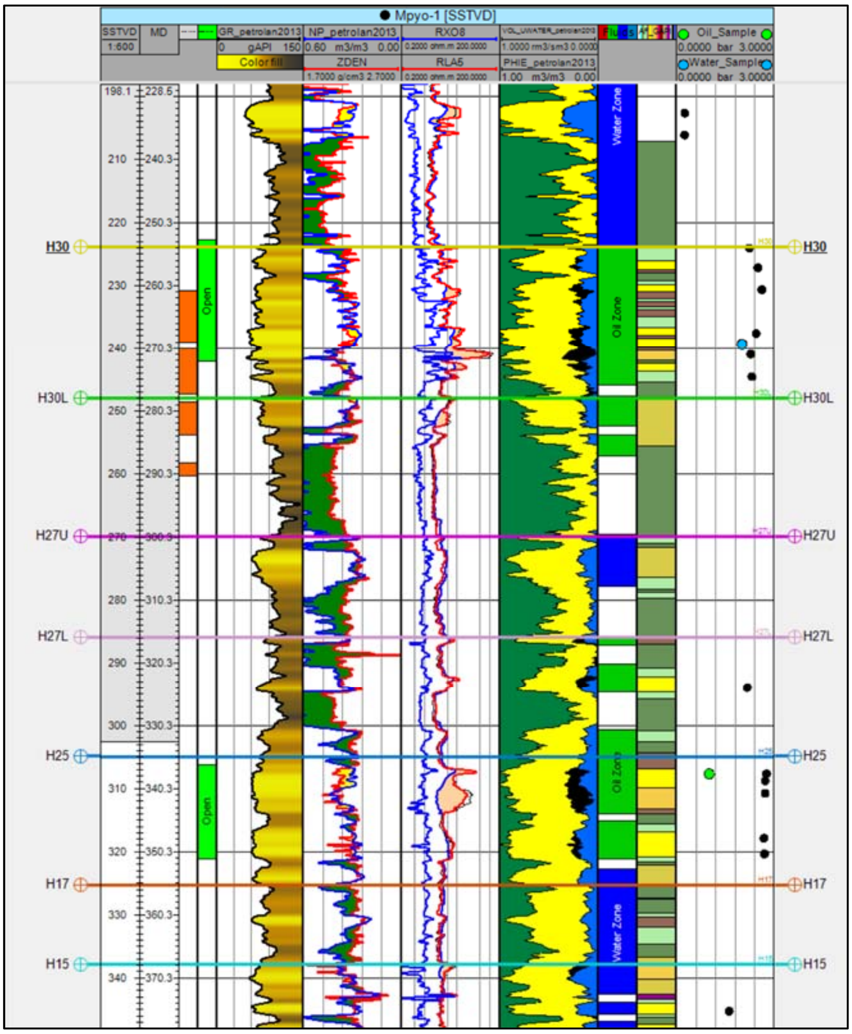


Figure 5-10 Mpyo-1 well

The stratigraphy and structural history of Mpyo are similar to those of Jobi East and reference is made to Sections4.2.2.1and 5.4.2.1for more description. As with Jobi East, reservoir quality is poorer and more variable in the eastern part of the Tilenga megastructure.

TRACS reviewed the seismic interpretation and depth mapping and concluded that the structural framework in the static models provided by Tullow were appropriate for use in determining GRVs.

The static model follows the same workflow as that of Jobi-Rii. TRACS reviewed the resulting property grids and associated volumes. Again, TRACS has some concerns surrounding the weighting of the seismic attributes versus the wells in the facies modelling.

5.5.2.2 Petrophysics review

Mpyo is another segmented field with multiple contacts. At Mpyo-1 the H27U contains reservoir quality sands but is water-bearing. Well Mpyo-2 which is shallower on the structure but in the northernmost segment is water-bearing. The quality of reservoir as well as the locations are influencing the fluid distribution in Mpyo.

NTG

The small range of NTG from the model has been expanded by TRACS allowing the ranges observed at the wells to influence the inputs. The mid NTG is similar in most cases but higher from wells in H30U and lower from wells in H27L.

NTG from Model					NTG difference				NTG From Logs			
	Low	Mid	High		Low Diff	Mid Diff	High Diff		Min NTG	Ave NTG	Max NTG	Zone
H30U	0.38	0.39	0.39		-0.16	-0.25	-0.31		0.53	0.63	0.70	H30U
H30L	0.15	0.15	0.14		0.15	0.04	-0.08		0.00	0.10	0.22	H30L
H27U	0.28	0.24	0.20		0.23	0.05	-0.21		0.05	0.19	0.41	H27U
H27L	0.19	0.18	0.16		0.19	0.11	-0.11		0.00	0.06	0.26	H27L
H25	0.45	0.42	0.40		0.35	0.01	-0.34		0.09	0.41	0.74	H25
									0.00	0.03	0.10	H17

Table 5-19 Mpyo average NTG from wells compared to model

Porosity

The mid porosity in the model is generally lower than the average porosity from the wells again with a very small range around the mid applied for the porosity. The wells indicate that there is a greater range in the porosity.

POROSITY from model					PHI Difference				Porosity from Logs			
	Low	Mid	High		Low Diff	Mid Diff	High Diff		Min Phi	Ave Phi	Max Phi	Zone
H30U	0.22	0.22	0.22		0.00	-0.03	-0.06		0.21	0.25	0.28	H30U
H30L	0.18	0.18	0.19		-0.02	-0.03	-0.09		0.20	0.21	0.28	H30L
H27U	0.26	0.24	0.22		0.07	-0.01	-0.09		0.19	0.26	0.32	H27U
H27L	0.24	0.25	0.26		0.03	0.00	-0.04		0.21	0.24	0.30	H27L
H25	0.21	0.21	0.22		0.02	-0.03	-0.04		0.19	0.25	0.27	H25
									0.20	0.21	0.22	H17

Saturation

Saturations are calculated in the same way as the other fields as described in Jobi-Rii section4.2.2.2. Mpyo has the added complication of a water-bearing segment high on the structure. A wide range of average So should be applied to the proven oil-bearing segments.

Contacts

An OWC is penetrated for H30U in Mpyo-3 at ~296m TVDSL. Other than this fluid-up-to and down-to are defining the range.

5.5.2.3 In place volumes

GRV

The contact ranges were reviewed and updates were made, some of which are significant, for instance in the Mpyo-4 segment. Where present, log OWCs of FWLs from pressures have been used to define the Mid case; a range of ±5m is used to define Min and Max case contacts.

In those reservoirs where no clear contact has been observed in the wells, log ODTs are taken as the Minimum. TRACS carried out an analysis of the column heights encountered in Mpyo and derived estimates for Min, Mid and Max columns expected across the field. They are 20m, 70m and 100m, respectively. Note that these column heights are based on observations from the Mpyo wells and not on cap rock integrity studies. The expected column heights were used to define Mid and Max case contacts unless a log WUT is available.

The Central North panel does not contain any wells but is surrounded by panels with proven oil in some reservoirs. In the Minimum case oil is assigned to the H30 reservoirs only. The Min case contact is defined by taking the crest of the structure in the panel and adding the Low case expected column height. In the Mid and Maximum cases oil is assigned to all reservoirs. The Mid and Max case contacts are defined by taking the crest of the structure and adding the Mid/High case expected column heights. Assumptions about vertical connectivity are guided by the observations in surrounding panels.

The calculated Min-ML-Max GRVs for each zone and segment were input into @Risk as P90-P50-P10 to allow for additional structural uncertainty, e.g. related to depth and thickness uncertainty.

Properties

The properties in the models are directly related to the facies models generated by Total. TRACS has reviewed the AEs against seismic attribute extractions and compared to well data.

The definition of the AEs looks reasonable and represents one valid realisation of AE distribution. The resulting facies model supports a better developed sand system in the West and sets up vertical connectivity observed in these western panels. There is of course a lot of detail beyond seismic resolution that could throw up surprises relating to NTG distribution, lateral compartmentalisation within a segment and possibly vertical compartmentalisation. The key message is that well averages of NTG might not be indicative of 3D averages.

The NTG averages from the Low and High case facies models were reviewed and compared to well data. TRACS has used information from the AE maps, model outputs and well statistics to guide the NTG distribution for each zone and each panel.

The same approach and methodologies as for previous fields (see Section 4.2.2.3) were used to generate the property ranges for the volumetrics.

All parameters were input as Min-ML-Max in a triangular distribution.

The oil formation volume factor is taken to be 1.04 for all zones and segments. Mypo has no gas cap.

Results

The range of in-place volumes for oil and gas for Mypo is shown in Table 5-20 and the split by panel shown in Table 5-21. It is clear that segments Mpyo-5A and Mpyo-3 are the greatest contributors in terms of in place volumes. An average gas oil ratio of 49 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	**P10**	**P50**	**P90**
STOIIP (MMbbls)	**All reservoirs panels**	**213.6**	**324.2**	**455.3**
GIIP (Bscf)	Solution gas	10.5	15.9	22.3
	Total gas	**10.5**	**15.9**	**22.3**

Table 5-20 Mpyo STOIIP and GIIP range

STOIIP (MMstb)	**P90**	**P50**	**P10**	***P10/P90***
Mpyo-1	24.2	38.8	59.7	*2.5*
Mpyo-3	66.7	92.8	121.9	*1.8*
Mpyo-4	26.6	53.1	84.6	*3.2*
Mpyo-5A	83.9	115.2	149.6	*1.8*
Mpyo-6	3.1	4.9	7.1	*2.3*
Central North	9.0	19.3	32.4	*3.6*
Total	**213.6**	**324.2**	**455.3**	***2.1***

Table 5-21 Mpyo STOIIP range (by region)

5.5.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Waterflood of multiple panel field

A simulation model was available for Mpyo-3, representing approximately 56% of the field's STOIIP. Recovery is consistent with PRR and accepted as reasonable. Recovery factor is consistent with fractional flow analysis.

Low, Mid and High cases in the PRR are dominated by static uncertainties but also contain a wide range of recoverable oil. These figures have been used with the mid case STOIIP to estimate the range of recovery factors.

The range of recovery factors for 50 years for Jobi East are presented in Table 5-22.

Field	Project		TRACS
			RF 50 yrs
Mpyo	Multiple panels	L	0.00
		M	0.08
		H	0.11

Table 5-22 Mpyo Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

5.5.3 Estimation of Mpyo Contingent Resources

5.5.3.1 Contingent Resources Development Pending

No CR Development Pending resources has been identified for Mpyo

5.5.3.2 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Mypo. This has been carried as DoH for oil and (solution) gas. The results are presented in section 5.5.4.

5.5.3.3 Contingent Resources Development not Viable

There are no resources in this category since Mypo does not have a gas cap.

5.5.4 Mypo CR summary

The total Contingent Resources for the Mpyo field are presented in Table 5-23 for oil resources and Table 5-24 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.0	25.9	50.1	0.0	7.3	14.2
Total All CR Categories	**0.0**	**25.9**	**50.1**	**0.0**	**7.3**	**14.2**

Table 5-23 Mpyo Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.0	0.6	1.2	0.0	0.2	0.3
Total All CR Categories	**0.0**	**0.6**	**1.2**	**0.0**	**0.2**	**0.3**

Table 5-24 Mpyo Gas Contingent Resource summary

6 KINGFISHER FIELD

6.1 FIELD BACKGROUND

Field Name	Kingfisher
Location	Albert Basin EA-3
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	CNOOC
Geology	The reservoirs are Miocene/Pliocene in age deposited in a fluvial/lacustrine deltaic setting. The field is a dip closed structure against a fault.
HCIIP estimate	Oil GIIP P90 – 401 MMstb 91 Bscf P50 – 587 MMstb 133 Bscf P10 – 820 MMstb 186 Bscf
Development type	Active water flood development, to be followed by polymer flood.
Number of current production & injection wells	4 E&A wells with 2 side tracks
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production. Awaiting Final Investment Decision

6.1.1 Contingent Resources

6.1.1.1 Geoscience review

The Kingfisher structure is divided into three panels: Main, North and South (Figure 6-1) with wells only in the Main panel. The reservoir interval comprises interbedded sandstones and shales deposited in a fluvio-lacustrine environment. There are four wells in the structure and the NTG varies rapidly both vertically (between zones) and laterally (between wells). No contacts have been encountered.

TRACS notes some minor issues with the current mapping, in particular near faults where horizons have been overly smoothed. In addition, comparison of the PSTM and PSDM data show clear differences in horizon shape in the Main and South parts of the fields. The Main field could be structurally deeper; the South part could be shallower. The supplied interpretation is based on the PSTM data. TRACS generated an alternative interpretation based on the PSDM data which also ties the wells.

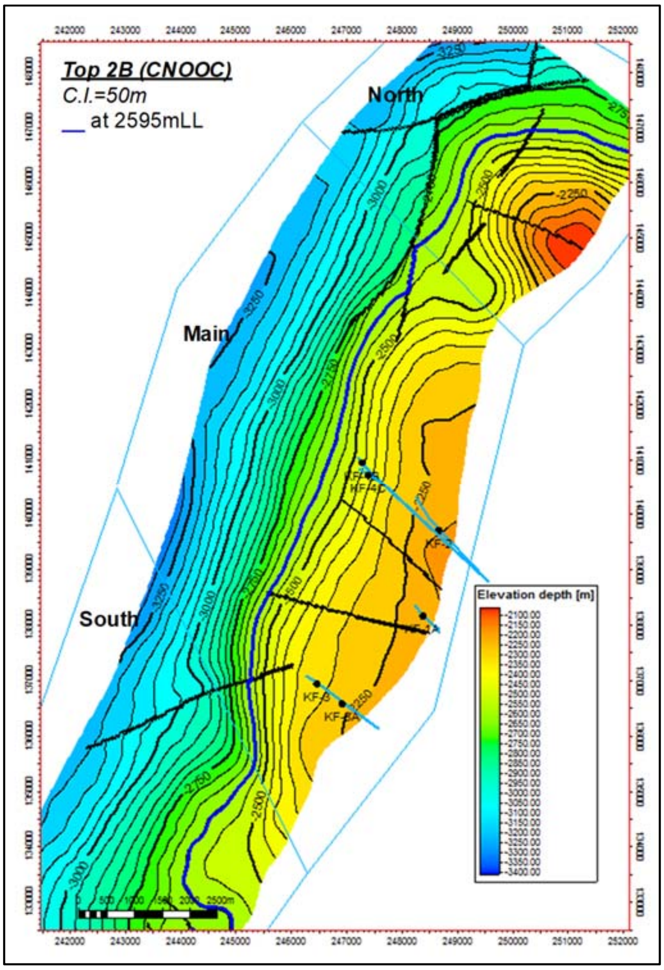


Figure 6-1 Kingfisher: CNOOC depth map (top 2B)

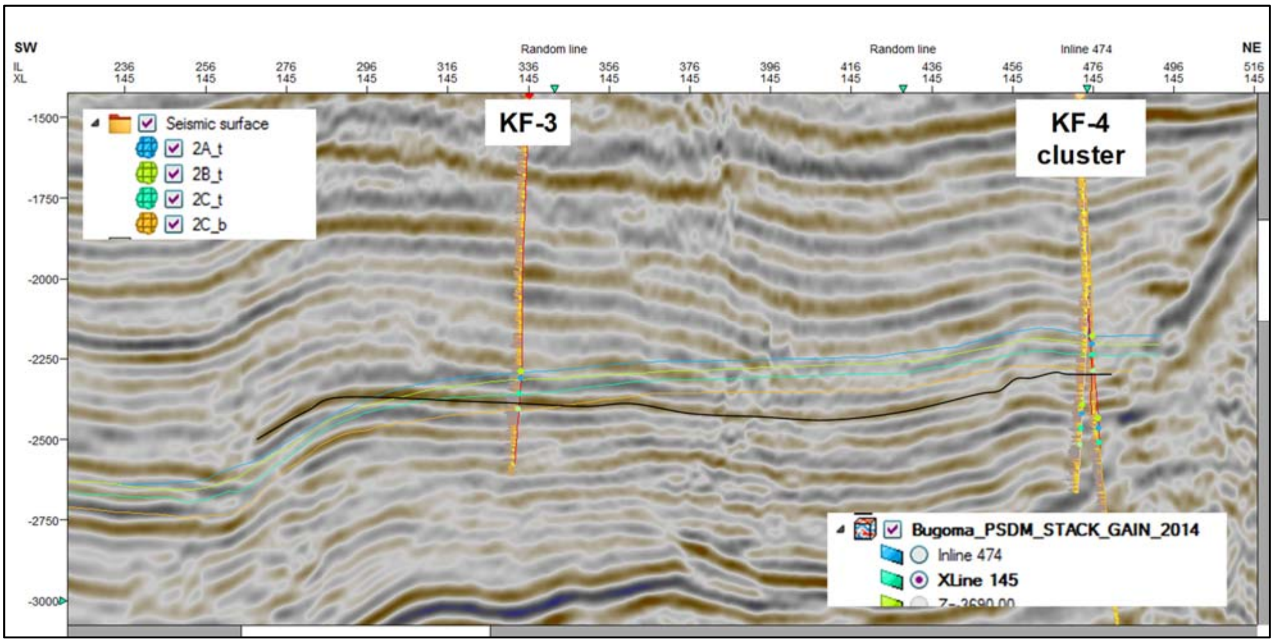


Figure 6-2 Kingfisher: comparison of PSTM and PSDM horizons

Tullow generated a probabilistic STOIIP range at field level using @RISK (all regions and all zones). TRACS reviewed the well data and the inputs/outputs of the mapping and STOIIP assessment.

6.1.1.2 Petrophysics review

A quick-look interpretation was carried on the Kingfisher wells and the results compared to the interpretations supplied. Interpretation input parameters described in the Kingfisher PRR were applied for the QL analysis (in this case for KF-4C) and the results identified specifically which of the supplied data had been used for average properties. Average properties from well interpretation as supplied are consistent with the NTG and Porosity in the PRR. Saturations are different due to the saturations in the model being calculated from saturation-height functions.

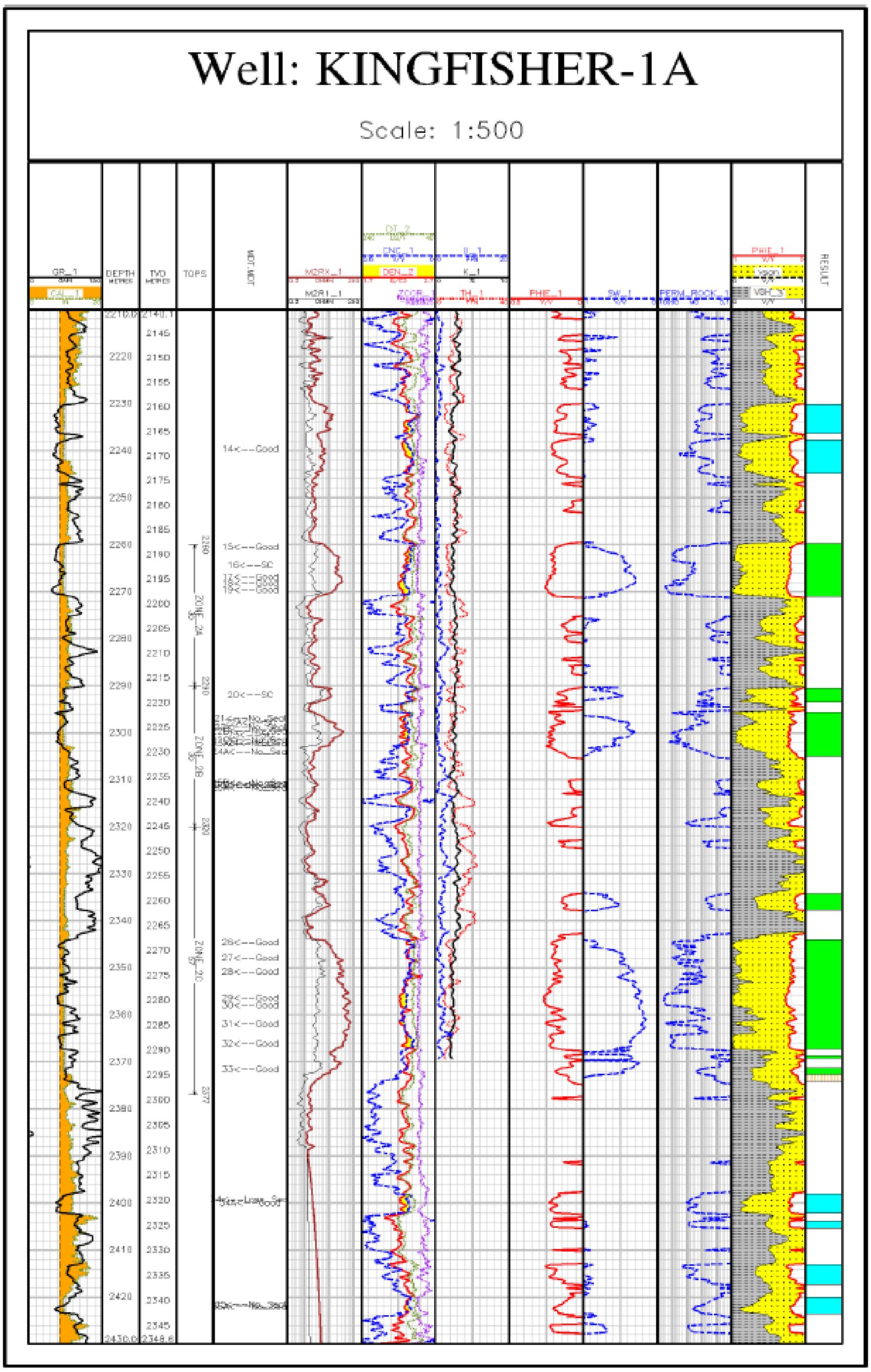


Figure 6-3 From Kingfisher PRR: KF-1A CPI; note water-bearing sands above Zone 2A

Figure 6-3 shows the oil-bearing sands in Zones 2A, 2B and 2C in well KF-1A which is high on the structure (Figure 6-5).

NTG

The reference NTG form the Petrel model is compared to the average NTG for all wells and to the range from the wells (Table 6-1). The difference in the average NTG form the wells and the model reference NTG are generally similar if a little lower in the model. The range applied in the volumes calculations is based on the high and low range from the wells.

PETREL REFERENCE PROPERTIES		NTG From Wells			NTG Diff
NTG		Low	Ave	Hi	
0.37	Zone 2A	0.20	0.38	0.56	0.01
0.23	Zone 2B	0.24	0.28	0.32	0.05
0.37	Zone 2C	0.22	0.44	0.62	0.07

Table 6-1 Kingfisher NTG from wells compared to reference NTG from model

Porosity

The reference modelled porosity is 2 to 3pu higher than the overall average from the wells (Table 6-2). The range from all wells is included in the range for the volume calculations with the mid also driven by the overall well average porosity.

PETREL REFERENCE PROPERTIES		PHIE from Wells			Phi Diff
PORO		Low	Ave	Hi	
0.25	Zone 2A	0.19	0.23	0.26	-0.02
0.22	Zone 2B	0.19	0.20	0.21	-0.03
0.23	Zone 2C	0.18	0.21	0.22	-0.02

Table 6-2 Kingfisher Porosity from wells compared to reference NTG from model

Saturation

The average So from wells is very similar to the reference So from the model, if a little lower in Zone 2A (Table 6-3). The range of So from the wells has been applied for the volume ranges.

PETREL REFERENCE PROPERTIES		So From Wells			So Diff
So		Low All	Ave Logs	Hi All	
0.68	Zone 2A	0.57	0.63	0.77	-0.06
0.64	Zone 2B	0.53	0.64	0.72	0.01
0.64	Zone 2C	0.53	0.67	0.77	0.03

Table 6-3 Kingfisher Oil Saturation from wells compared to reference NTG from model

Contacts

The base case OWC from the PRR is included in Figure 6-5. Pressure data indicates that Zone 2A is in lateral communication throughout and is vertically isolated from Zones 2B and 2C. Zones 2B and 2C are in communication with each other – though 2B is split into Upper and Lower for a low case.

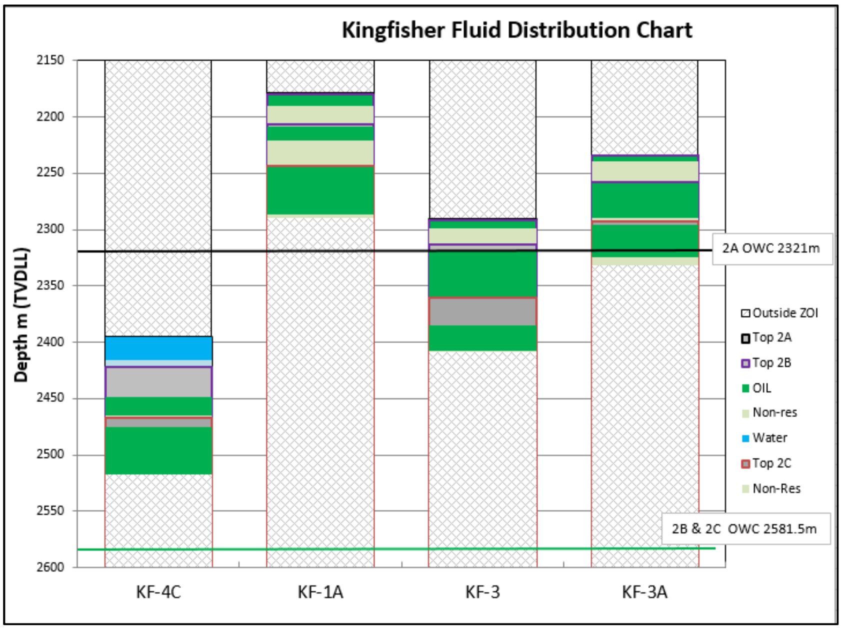


Figure 6-4 Kingfisher fluids from logs

Fluid distribution from logs in the Kingfisher wells support two contacts for the whole sequence across the field (Figure 6-4). The contacts marked on the plot are the reference contacts from the PRR. There is some uncertainty around the pressure data and the contact is sensitive to this. A range of contacts has been defined by TRACS and the reference case from the PRR is within the defined range.

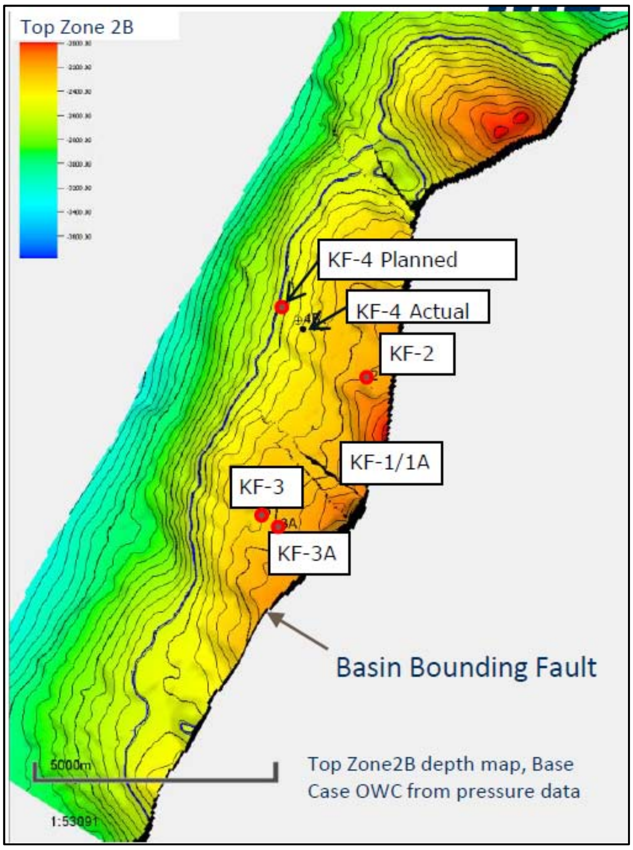


Figure 6-5 From Kingfisher PRR: Kingfisher well locations on Top Zone 2B

6.1.1.3 In place volumes

TRACS methodology

TRACS has split the volumes by region (Main, North and South) and by zone (2A, 2B and 2C) to allow uncertainty ranges by region and zone to be assessed. The Main segment with its four wells should have a narrower uncertainty range than the North and South parts which have no wells.

TRACS adopted an expectation curve approach in order to develop an independent view of the GRV range by region and for the full field. Where the Tullow inputs were reasonable these have been accepted, elsewhere modifications have been made. The revised GRVs were combined with the updated rock property ranges in @Risk to derive a probabilistic STOIIP range by region and for the full field.

Contacts and *GRV*

GRV expectation curves have been generated for each zone and each region. The expectation curves contain four variables to give 54 realisations:

- 2 maps
- 3 map flexes
- 3 contacts
- 3 isochores

Overall the TRACS map is more pessimistic, except in the South where it is much more optimistic. A weighting of 75% has been given to the CNOOC map and 25% to the TRACS map.

The CNOOC map has been flexed up and down to investigate depth uncertainty away from the wells. The flexing analysis shows that the GRV change in Main and North is ~5-10%, while in the South it is ~15-40%. These results are not surprising given the good well control in the Main area and the relatively small size of the North.

The contact range derived from the petrophysics (Section 6.1.1.2) and tabulated in Table 6-4 has been used for all areas of the field. The impact on GRV in the Main panel is 0-20% depending on the zone.

Depths in mSL	**TRACS**		
	Min	**ML**	**Max**
Zone 2A	2321	2327	2332
Zone 2B	2493	2553	2613
Zone 2C	2571	2592	2613

Table 6-4 Kingfisher contact range

TRACS conducted a sensitivity analysis on the CNOOC isochores. Note that the 2A isochore in the North is effectively zero. TRACS has generated a small, but non-zero isochore in the North to enable sensitivity analysis. Isochore flexing gives ~8-15% change in GRV depending on zone and region.

In addition, there is some uncertainty in the exact positioning of the basin bounding fault. However, this uncertainty is considered to be second order compared to other parameters.

The realisation trees were set up and probabilities assigned to each parameter to generate the GRV expectation curves. Min-Most Likely-Max values were selected and input to a triangular distribution in @Risk as P90-P50-P10 values. A sample expectation curve is shown in Figure 6-6.

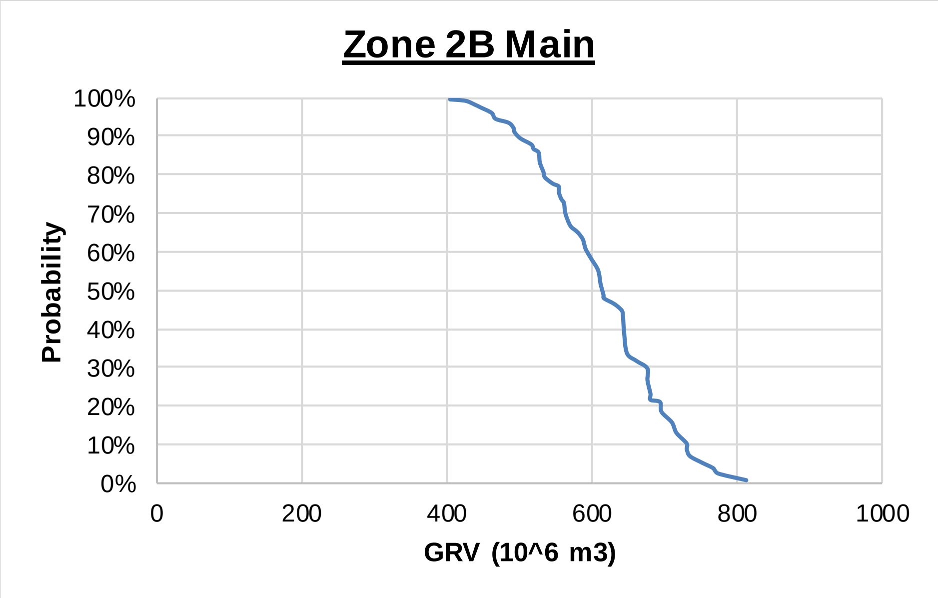


Figure 6-6 GRV expectation curve: Zone 2B Main

The results in Figure 6-7show that the GRV range in the Main area is limited which reflects the well control: three wells spaced out along the structure and one further down dip. The GRV range is widest in the South which reflects the impact of the alternative map.

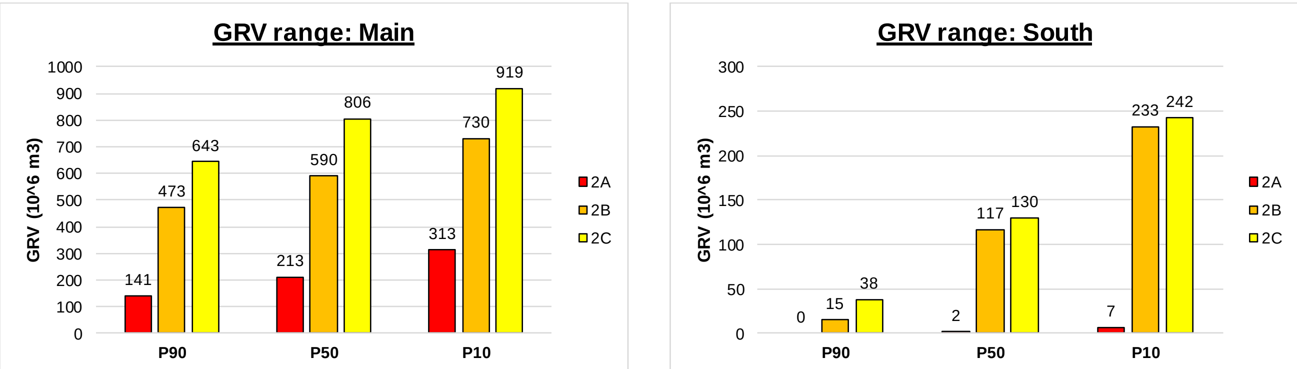


Figure 6-7 GRV ranges: Main and South

Properties

TRACS has used the well averages as the basis for the NTG range in each zone. The Minimum and Maximum are taken from the minimum/maximum seen in the wells. The well average for each zone has been selected as the Most Likely value. The NTG ranges are input as a triangular distribution in @Risk.

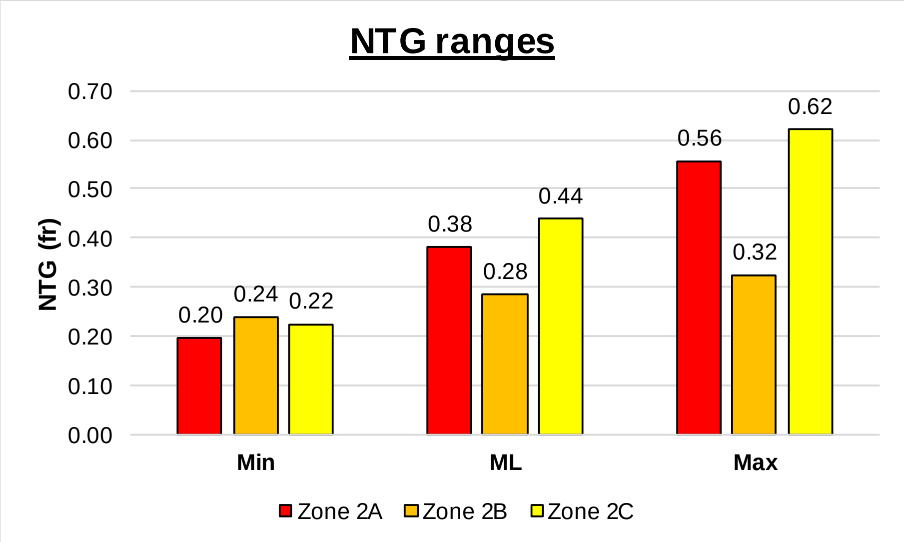
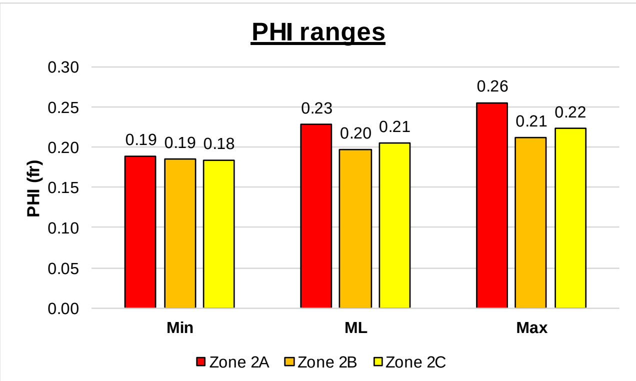


Figure 6-8 Kingfisher: NTG ranges

A similar approach has been adopted for the porosity except that in Zone 2B and Zone 2C the High case have been taken from the geological model to widen the range and capture potential upside. The So range follows the NTG methodology. The zonal property ranges have been used in all three regions. All parameters were input using a triangular distribution and a strong dependence was implemented between So and PHI.



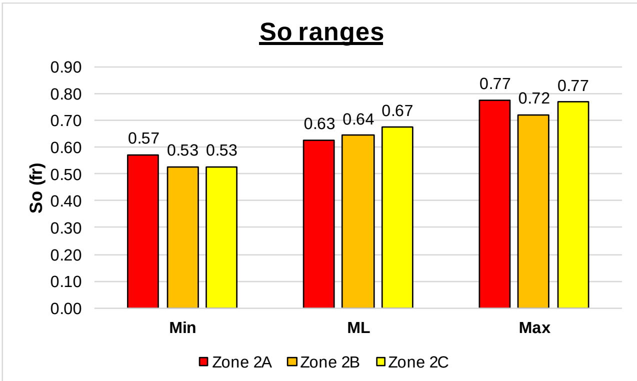


Figure 6-9 Kingfisher: PHI and So ranges

TRACS has updated the distribution for shrinkage (Table 6-5); the same Boi range has been used for all zones and regions. There is no gas cap in Kingfisher.

Boi (v/v)	**Min**	**Mean**	**Max**
all zones/regions	1.15	1.18	1.20

Table 6-5 Kingfisher Boi range

Results

The probabilistic volumes for each zone and region have not been convolved probabilistically but summed in order to keep the resulting range wide as there is still a lot of sub-surface uncertainty. The range of in-place volumes for oil and gas for the Kingfisher field are presented in Table 6-6. The STOIIP has been split between the Main, North and South areas. The GIIP is presented as solution gas. There is no Free GIIP reported for Kingfisher. An average gas oil ratio of 227 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	Phase 1: Main	306.4	422.7	560.1
	North	59.6	92.4	137.0
	South	34.6	71.9	122.8
	All reservoirs panels	**400.6**	**587.1**	**819.8**
GIIP (Bscf)	Solution gas	90.9	133.3	186.1
	Gas cap gas	0.0	0.0	0.0
	Total gas	**90.9**	**133.3**	**186.1**

Table 6-6 Kingfisher STOIIP range (by region)

6.1.1.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Phase 1 waterflood (main field)

The Kingfisher full field dynamic simulation model with water injection development was reviewed to generate an understanding of the recovery mechanism for the pattern flood. The Mid case recovery factor from the model is consistent with the recovery factor in the PRR, although it is noted that the development plan and STOIIP are not exactly the same. Investigation of the recovery factor distribution shows a different behaviour to the Tilenga reservoirs and a macroscopic/ microscopic analysis could be used to estimate recovery factors. However, for consistency we conclude that the model recovery factor is acceptable.

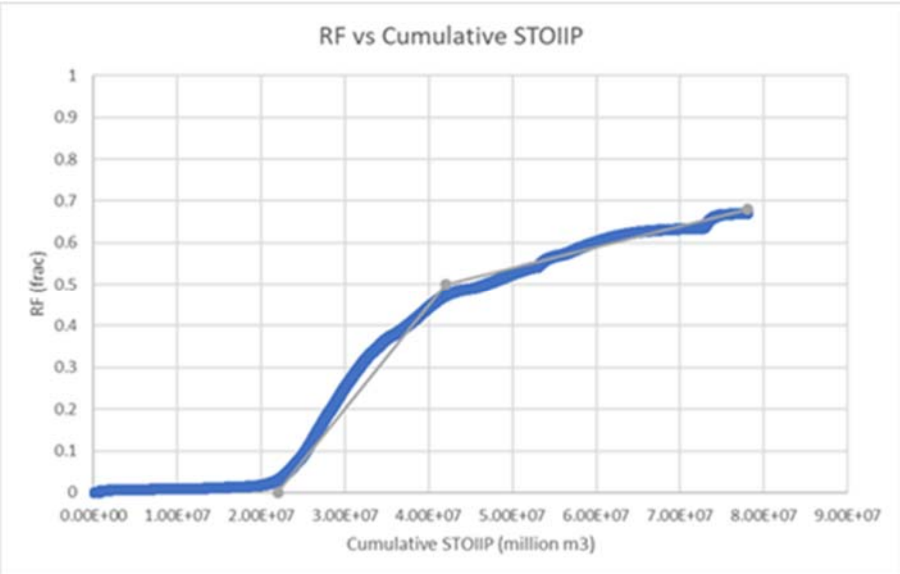


Figure 6-10 Recovery factors by cell vs cumulative STOIIP for Kingfisher

No Low or High case models were provided for Kingfisher. Low and high case recovery factors are reported in the PRR, but have a relatively narrow range and are dominated by static uncertainties (see Figure 6-11). Sensitivities in the PRR show that Sor is the dominant dynamic uncertainty but this is still only -7%/+9% which seems to narrow. However, it is likely that relative permeability will also be uncertain so a range of -15% and +25% has been used, similar to the Tilenga fields. The 50 year recovery factors were estimated using fractional flow analysis with two times the PV injected.

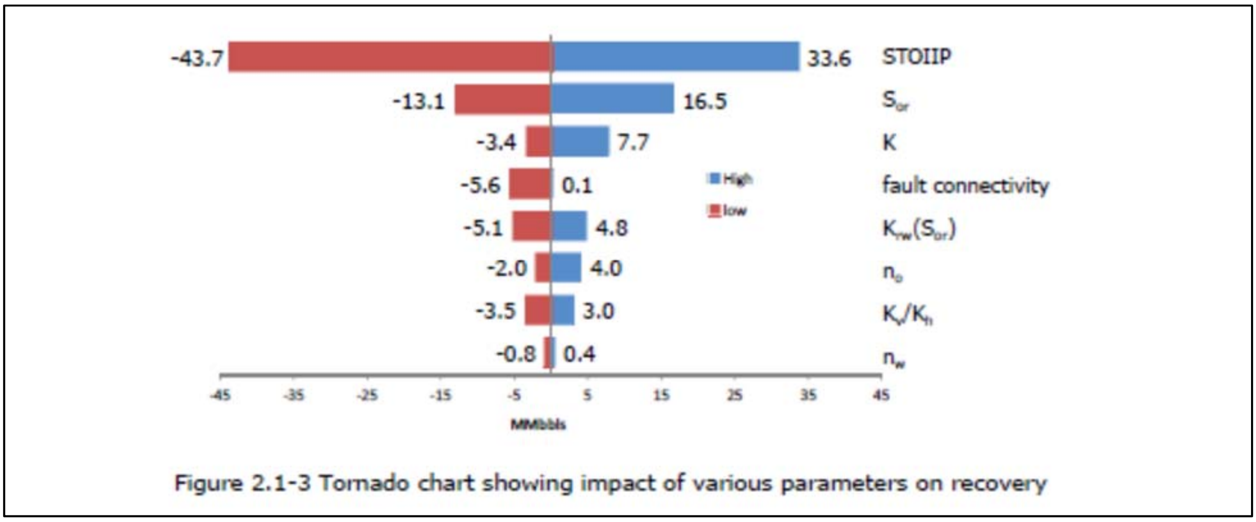


Figure 6-11 Figure 2.1-3 showing sensitivity to various parameters

The resulting range of recovery factors for the Kingfisher Phase 1 oil development is presented in Table 6-7 for 25 and 50 years.

Field	**Project**		**TRACS**	
			25 yrs	**50 yrs**
Kingfisher	Waterflood Main	L	0.28	0.32
		M	0.33	0.38
		H	0.41	0.47

Table 6-7 Kingfisher Phase 1 Recovery Factors

The Mid case simulation model was re-run with 50 years of production forecast. Although the Kingfisher full field dynamic model covered Kingfisher North block with 4 production and 1 water injection wells, Tullow does not carry Kingfisher North in the Phase 1 development plan. Therefore, only the simulation results from the Kingfisher main block were used to generate the type curves of oil rate vs cumulative oil production for inputs into the type curve tool to generate the production forecast profiles with the CPF constraints.

The oil production wells are constrained by a maximum liquid production rate of 6500 ~ 7500 bopd and a maximum oil rate of 3200 ~ 4800 bopd. A minimum BHP of 110 bars and a maximum downhole pressure drawdown of 35 bars are also applied to all production wells . Furthermore, a minimum oil rate of 30 bopd (5 Sm3/day) and a maximum water cut of 98% are applied to all production wells.

The maximum water injection rate per well is 11 ~ 12.5 Mbwpd. The maximum injection BHP is 4350 psia. The water injection rate is also controlled by 100% reservoir voidage replacement.

Furthermore, a maximum oil rate of 40 Mbopd and a maximum liquid production rate of 120 Mblpd are set as the CFP constraints at field level.

The well operating efficiency is 95%. The CPF operating efficiency are 100%, as the CFP facility constraints have already taken account of the downtime factor.

The forecasts of oil production profiles were generated from the type curve tool for the Phase 1 project (Main area), honouring the constraints of the CPF for Kingfisher project. The resulting range of profiles for Kingfisher are presented in Figure 6-12.

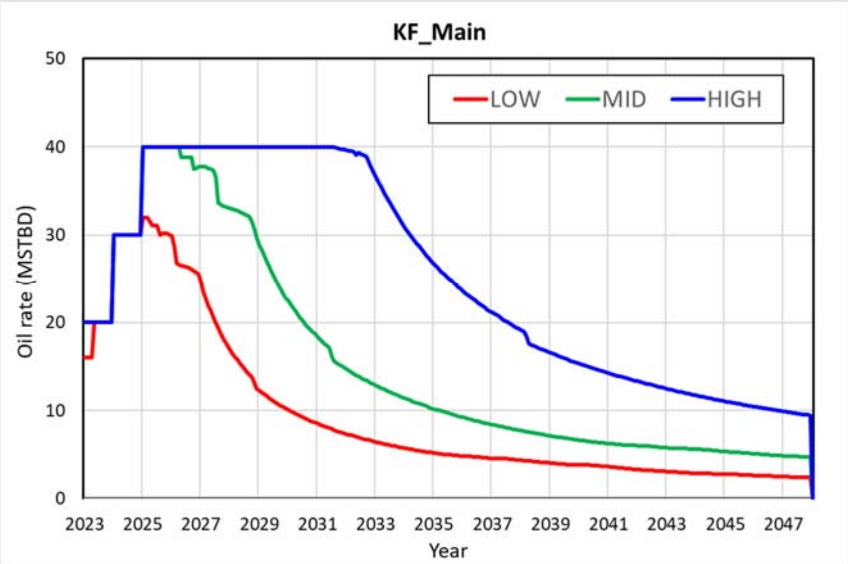


Figure 6-12 Oil production forecast -- Kingfisher Field Phase 1

Polymer flood

No models were available for Kingfisher and it was concluded that the same incremental benefits should be assumed as for Ngiri owing to similar fluid properties and relative permeabilities. These represent incremental recovery factors of +4%/+5%/+6% in the Low, Mid and High cases for 25 year field life.

The range of recovery factors for a polymer flood at 25 and 50 years as estimated by TRACS is presented in Table 6-8.

Field	Project		TRACS	
			25 yrs	50 yrs
Kingfisher	PF All	L	0.32	0.38
		M	0.38	0.46
		H	0.47	0.57

Table 6-8 Kingfisher Recovery Factors for Polymer Flood

No production profiles were generated for this project as a commerciality test was not required.

6.1.2 Development plans and cost estimates

The oil production and water injection wells will be located at 4 well pads within the EA-3 licence. From the well pads production will be sent to a Central Processing Facility (CPF) via a buried pipeline network. Water will be returned to the well pads for re-injection. At the CPF the oil will be stabilised, desalted and dehydrated to the export specification. The CPF design capacity will based peak annual average production rates of:

- Oil, 40,000 bbl/d
- Gas, 11 MMscf/d
- Gross liquids, 120,000 bbl/d
- Produced water treatment, 120,000 bbl/d
- Water injection, 120,000 bbl/d

The oil will be sent via an electrically heated pipeline, to the planned Kabaale refinery approximately 50km north east of the Kingfisher field and then onwards to the East African coast via the Export Pipeline System (EPS). Only the Kingfisher to Kabaale pipeline is part of the project scope and Capex. The JV partners will also pay a tariff to the pipeline company, to cover the transportation fee to Kabaale.

At the CPF all associated gas will be used to generate electrical power for the needs of the CPF and electrical heat tracing of the feeder line between the CPF and Kabaale. Any excess electrical power will be fed into the national electricity grid.

FEED studies for the facilities and pipelines are complete. FID is dependent on the resolution of commercial negotiations. For the purpose of this CPR the first oil date assumed is Q1 2023 (see Section 4.1.2 for more background on the start date) .

Tullow provided a cost summary of the development Capex in the form of a slide pack from the "Kingfisher Economics Workshop With Partners, March 2019" and produced by the Operator.

Capex $MM RT19	Past costs	Point forward 1/1/2019	
		CNOOC	Tullow DP CR
Pre-2012 Exploration & Appraisal	245		
2012 -2018 (E&A, Owners costs)	417		
Pre-FID, 2019 (seismic, Owners costs)		88	88
Engineering and Facilities - CPF		489	481
Engineering and Facilities - Pipeline		74	81
Drilling and Completion		521	420
Wellpads and Trunklines		106	90
G&G study		20	20
Site camps and logistics		60	60
QHSE & ESIA		11	11
Pre-Opex		50	50
G&A, support costs		120	120
Total	**662**	**1,539**	**1,421**

6.1.2.1 Kingfisher well costs

Well durations are based on CNOOC global assets, with added factors for geological and technical content, Uganda environment and well complexity. Service and logistic cost are based on previous wells with 10-20% contingency costs dependent on well complexity and ERD requirements. This is a reasonable approach to take. No detail was available for review of well design or well architecture.

Well costs provided were at a high level i.e. total cost per well. Provided rig day rates are within the range of costs seen in previous market enquiries. Additional breakdown was given in the form of % split of costs across service categories (Tangibles, rig, Service & Consumables, overheads etc.) Rig costs make up a higher percentage of well cost than Tilenga but this is to be expected as rig rates will vary with market forces and rig specification.

Taking in to account total well cost and proportion of split between cost type well costs are within the expected range.

6.1.2.2 Facilities costs and Opex

A 2016 Facility Cost Estimate Report from the project feasibility stage indicates that about 45% of the Facilities cost is attributable to the CPF.

The majority of the costs in the table above i.e. the engineering, facilities, drilling and completion cost are based on the FEED study and market price updating. On this basis if the scope is well defined the Capex forecast carries a relatively high level of accuracy. TRACS however did not sight the offers.

A small proportion of the facilities-related Capex in the table above is for Kabaale shared facilities. Capex allocation between the EA-1, EA-2 (N) and EA-3 licences will be based on the ratio of FID resources in each licence, fixed at 65%:17%:18%.

The exclusion of Kingfisher North removes one producer and two injectors plus the associated well pad and trunk line section from the DP CR scope. The pipeline and CPF Capex has been updated since the workshop.

The resulting point forward phased Capex for DP CR only for the EA-3 licence area is shown below.

EA-3 Capex ($MM RT19)	2020	2021	2022	2023	2024	2025	2026	2027	2028
Wells	-	45	82	75	60	76	81	-	-
Surface	61	225	257	111	-	-	-	-	-
Pre-FID, seismic	-	-	-	-	-	-	-	-	-
Owners costs	62	66	119	3	3	3	3	3	3
Total	**123**	**336**	**458**	**188**	**63**	**79**	**83**	**3**	**3**

The "Kingfisher Economics Workshop" slides quote the total 25 year Opex to be $1,775MM RT19, equating to $8.1/bbl over the production period to end 2042. At approximately 5% of the development Capex the annual Opex is high, but not unreasonable given the remoteness of the location, the immaturity of the in-country oil industry and necessary levels of Opex cost contingency. This percentage is also consistent with that of Tilenga. Approximately a third is well integrity related.

The annual Opex profile in the Operator's model, whilst carrying the same total field life Opex as described on the workshop slides does not agree on a year-by-year basis. TRACS understand that the economic model carries the latest Opex. It is approximately flat in real terms at $70MM per year and allows for power import from year 10 of production. TRACS would expect that savings would be made to the annual Opex as operational experience is gained.

The Kabaale Shared Services Opex will be allocated based on the ratio of yearly production between EA-1, EA-2 (N) and EA-3.

The Operator's economic model assumes a tariff of $12.77/bbl (base date 2019) payable to the pipeline company by the JV partners to cover the transportation fee to Kabaale. This was updated to a base date consistent with Tullow's approach to Tilenga (2023).

6.1.2.3 Decommissioning costs

Decommissioning costs are quoted by the Operator as $31MM for facilities and $28MM RT19 for wells in both the workshop slides and economic model.

At 5% of the surface development Capex in TRACS opinion the surface facilities decommissioning costs are very low and carry a high level of uncertainty given that there are no benchmark projects. The well abandonment cost at $0.9MM RT19 per well is reasonable?

Abandonment provision will be made from the year in which 50% of the expected economic recoverable oil is reached.

6.1.3 Chance of Commerciality for Kingfisher and Phase 1

Based on the current status of the project (see Section 1.2) the CoC of Phase 1 (Tilenga and Kingfisher) is estimated to be 50%. This is predominately a commercial risk reflecting the current suspension of the project.

6.1.4 Estimation of Kingfisher Contingent Resources

The Kingfisher field will be developed as part of the Phase 1 development project. All resources associated with Kingfisher are classified as Contingent Resources (CR).

6.1.4.1 Contingent Resources Development Pending

The Kingfisher Phase 1 development is categorised as CR Development Pending (DP). The methodology for generating the DP resources is the same as Jobi Rii.

The oil DP Contingent Resources for Kingfisher are presented in Table 6-11. The Development Pending resources are cut-off at end of 2042 which is the end of the Kingfisher licence (EA3). Note that there are no gas DP Contingent Resources as a gas sales solution still needs to be matured.

6.1.4.2 Contingent Resources Development on Hold

Oil

The key oil projects that have no firm plans for development but have been studied and could form part of further phases of development. These are categorised as Development on Hold (DoH) resources. The projects for Kingfisher are summarised below.

- Extension of Phase 1 reservoirs waterflood from COP to 50 years
- Development of Kingfisher North
- Development of Kingfisher South
- Polymer flood of Phase 1 reservoirs

The same approach as Jobi Rii has been used for generating the range of resources. The overview of DoH oil resources by project is presented in Table 6-9.

CR DoH Oil	Gross (MMbbls)		
	1C	2C	3C
Phase 1 WF extension	17.9	30.7	54.5
Kingfisher North	14.5	26.8	49.3
Kingfisher South	11.2	27.3	58.0
Polymer Flood	28.7	52.9	93.2
Total all oil DoH	**72.3**	**137.8**	**255.0**

Table 6-9 Kingfisher Oil DoH Contingent Resource summary

Gas

The solution gas recovery associated with the Phase 1 oil project as well as the other oil projects have been classified as DoH. The overview of DoH gas resources by Kingfisher project is presented in Table 6-10.

CR DoH Gas	Gross (MMbbls)		
	1C	2C	3C
Phase 1	7.8	14.7	23.8
Phase 1 WF extension	3.4	3.5	6.2
Kingfisher North	1.6	3.0	5.6
Kingfisher South	1.3	3.1	6.6
Polymer Flood	3.3	6.0	10.6
Total gas DoH	7.8	14.7	23.8

Table 6-10 Kingfisher Gas DoH Contingent Resource summary

6.1.4.3 Contingent Resources Development not Viable

There are no resources in this category since Kingfisher does not have a gas cap.

6.1.5 Kingfisher CR summary

The total Contingent Resources for the Kingfisher field are presented in Table 6-11 for oil resources and Table 6-12 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development Pending	80.9	129.9	209.9	8.1	13.0	21.0
Development on Hold	72.3	137.8	255.0	7.2	13.8	25.5
Total All CR Categories	**153.2**	**267.7**	**464.9**	**15.3**	**26.8**	**46.5**

Table 6-11 Kingfisher Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	17.4	30.4	52.8	4.9	8.6	14.9
Total All CR Categories	**17.4**	**30.4**	**52.8**	**4.9**	**8.6**	**14.9**

Table 6-12 Kingfisher Gas Contingent Resource summary

7 KAISO-TONYA FIELDS

7.1 OVERVIEW

The Kaiso-Tonya fields consist of the following three fields:

- Waraga
- Mputa
- Nzizi

The fields are located to the north east of Kingfisher as shown in Figure 1-1. There are no firm development plans for the fields (they are not part of the Phase 1 development) but they are expected to be candidates for a waterflood development.

This section presents the volumetrics and recoverable resources associated with the field.

7.2 WARAGA FIELD

7.2.1 FIELD BACKGROUND / INTRODUCTION

Field Name	Waraga
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field is formed by structural trapping.
HCIIP estimate	Oil GIIP P90 – 85 MMstb 17 Bscf P50 – 105 MMstb 22 Bscf P10 – 127 MMstb 26 Bscf
Development type	Active water flood development
Number of current production & injection wells	3 E&A wells with 1 side track
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production.

7.2.2 Contingent Resources

7.2.2.1 Geoscience review and in place volumes

Introduction

Waraga is the northernmost field in the Kaiso Tonya area. There are four main reservoir packages that have been further subdivided.

- H10M: thin oil sand
- H15: thin oil sands in the Upper and Middle units
- H20L: thick clean sand below a thick shale

- H45: predominately thick, clean sands in the Lower and Middle units with more interbedded sands in the Upper unit

Fluid levels vary vertically to give a series of stacked pools.

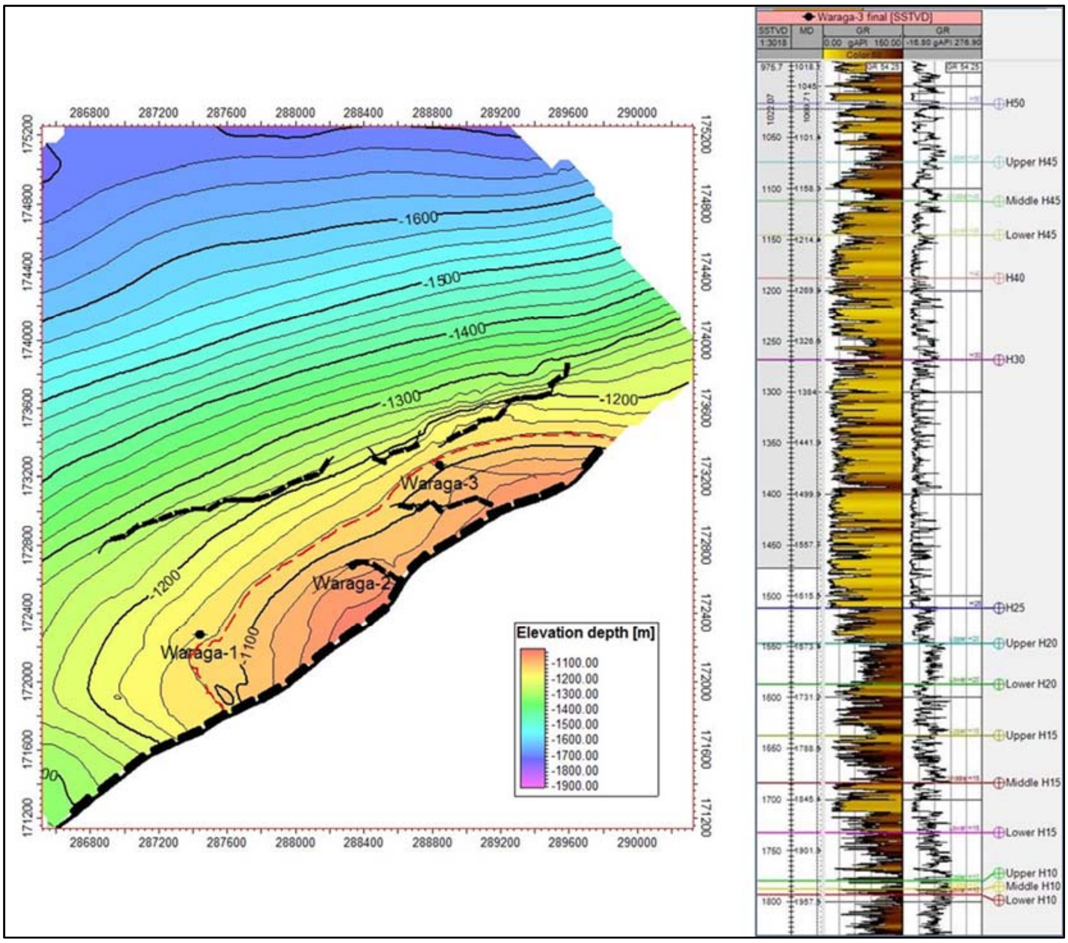


Figure 7-1 Waraga: Tullow depth map and Waraga-3 well

The stratigraphy and structural history of Waraga are similar to those of the Tilenga Phase 1 fields and reference is made to Section 4.2.2.1 for more description. There are, however, some differences with the Tilenga fields and the other Kaiso-Tonya fields. The sediments were deposited in a predominately fluvial/lacustrine alluvial fan environment. The older reservoirs show a mix of depositional environment whereas the younger sediments are interpreted to be mostly fluvial.

The Waraga Field is located at the northern tip of the Kaiso-Tonya relay zone and has received vast amounts of sediment compared to the other Kaiso-Tonya fields. It has been suggested that Waraga has been supplied by a separate depositional system draining a large catchment area to the southeast of the field. Waraga is not filled to spill unlike the other Kaiso-Tonya fields.

The petrophysical description is accepted as is.

Tullow did not supply any static or dynamic models of the Waraga Field.

In place volumes

The Waraga Field carries low Contingent Resources and, therefore, was not reviewed in detail. TRACS carried out a high level review of the inputs to Tullow's (Total's) volumetric estimates.

The GRV inputs as tabulated in the PRR were accepted as is and were input as P90-P50-P10 in the @Risk deck.

Rock property ranges were back-calculated (from PRR tables) and reviewed; they were found to be very narrow. A review of the well averages shows that there is variability between wells. While the wells may not be completely representative of the 'global' average of the reservoirs/field, the range of the global average should reflect the variability in reservoir quality that would be expected in such a depositional system. TRACS made updates to the NTG, PHI and So property ranges for all reservoirs. The emphasis was on ensuring the ranges are sufficiently wide. The property ranges are input as a triangular distribution in @Risk.

The oil formation volume factor is taken to be 1.11for all zones and segments. Waraga has no gas cap.

The range of in-place volumes for oil and gas for Waraga is shown in Table 7-1. An average gas oil ratio of 206 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	**Total oil**	**84.7**	**104.8**	**127.8**
GIIP (Bscf)	Solution gas	17.4	21.6	26.3
	Total gas	**17.4**	**21.6**	**26.3**

Table 7-1 Waraga STOIIP and GIIP range

7.2.2.2 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Waterflood project

One Mid case simulation model was provided for Waraga. No reports were available. The recovery factor from the model was consistent with the Tullow CR summary and the model recovery factor was used for the Mid case.

The Low and High case recovery factors were based on the Kingfisher range, as were the 50 year forecasts.

The range of recovery factors for 50 years for Waraga are presented in Table 7-2.

Field	Project		TRACS
			50 yrs
Waraga	Waterflood	L	0.23
		M	0.28
		H	0.35

Table 7-2 Waraga Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

7.2.3 Estimation of Waraga Contingent Resources

No CR Development Pending resources has been identified for Waraga.

7.2.3.1 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Waraga. This has been carried as DoH for oil and (solution) gas. The results are presented in section 7.2.4.

7.2.3.2 Contingent Resources Development not Viable

There are no resources in this category for Waraga.

7.2.4 Waraga CR summary

The total Contingent Resources for the Waraga field are presented in Table 7-3for oil resources and Table 7-4 for gas resources.

CR Oil	**Gross (MMbbls)**			**Tullow Working Interest (MMbbls)**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Development on Hold	19.9	28.9	44.1	5.6	8.2	12.5
Total All CR Categories	**19.9**	**28.9**	**44.1**	**5.6**	**8.2**	**12.5**

Table 7-3 Waraga Oil Contingent Resource summary

CR Gas	**Gross (Bscf)**			**Tullow Working Interest (Bscf)**		
	1C	**2C**	**3C**	**1C**	**2C**	**3C**
Development on Hold	2.0	3.0	4.5	0.6	0.8	1.3
Total All CR Categories	**2.0**	**3.0**	**4.5**	**0.6**	**0.8**	**1.3**

Table 7-4 Waraga Gas Contingent Resource summary

7.3 MPUTA FIELD

7.3.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Mputa**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are moderate quality sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field consists of five fault-bound panels in a structural trap (dip and fault closure).
HCIIP estimate	Oil GIIP P90 – 102 MMstb 15 Bscf P50 – 131 MMstb 20 Bscf P10 – 164 MMstb 25 Bscf
Development type	Phased active water flood development
Number of current production & injection wells	5 E&A wells
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production.

7.3.2 Contingent Resources

7.3.2.1 Geoscience review

Mputa lies 15km to the southwest of Waraga and is divided into six fault panels (see Figure 7-2), of which five have been penetrated by wells. There are two main reservoir packages, H15 and H20 (Figure 7-2),with some additional pay in the H10. The reservoirs are interpreted to be fluvio-deltaic channel sands and channel mouth bars interbedded with claystones of fluvial/lacustrine origin. The channel bodies appear to be isolated and encased in mud.

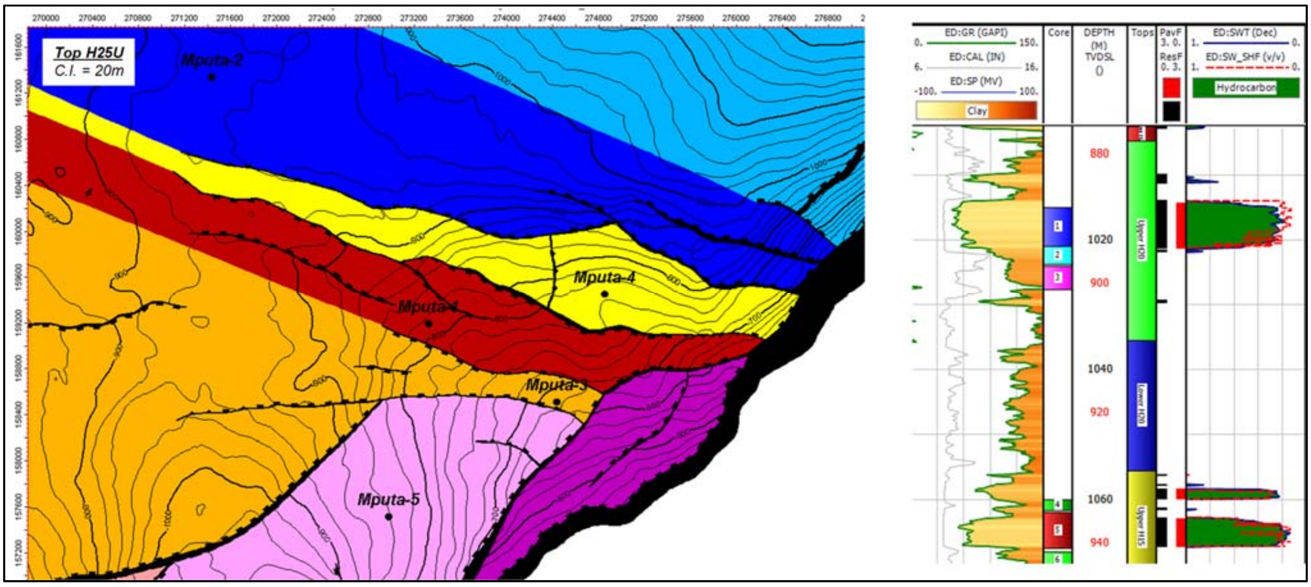


Figure 7-2 Mputa depth map and Mputa-5 well

The stratigraphy and structural history of Mputa are similar to those of the Tilenga Phase 1 fields. There are, however, some differences with the Tilenga fields. Mputa lies close to the breach point of the Kaiso-Tonya relay ramp. As such the area has undergone complex movement leading to a highly compartmentalised structure.

The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

TRACS reviewed the seismic interpretation and depth mapping and concluded that the maps used by Tullow were appropriate for use in determining GRVs.

7.3.2.2 Petrophysics review

The petrophysical description is accepted as is.

Limited data is available for Mputa and properties from the Petrel model are not split into usual U and L units. It is evident from the Petrel properties (Table 7-5) a small range is applied to the NTG and the porosity. The properties from the PRR for H15U indicate that the average porosity in the model is high but the mid NTG is the same as the wells.

	NTG Petrel		
	Low	Mid	High
H25	0.25	0.22	0.20
H20	0.22	0.25	0.27
H15	0.34	0.35	0.43
H10	0.17	0.13	0.18
	POROSITY Petrel		
	Low	Mid	High
H25	0.26	0.26	0.27
H20	0.28	0.27	0.28
H15	0.30	0.29	0.30
H10	0.28	0.28	0.28
	SO Petrel		
	Low	Mid	High
H25	0.40	0.55	0.58
H20	0.46	0.54	0.59
H15	0.50	0.62	0.62
H10	0.40	0.51	0.56

Table 7-5 Mputa low-mid-high properties from Model

	Zone	NTG	PhiAvg
Mputa-1 AH Log	H15U	0.12	0.28
Mputa-2 AH Log	H15U	0.35	0.32
Mputa-3 AH Log	H15U	0.46	0.33
Mputa-4 AH Log	H15U	0.28	0.31
Mputa-5 AH Log	H15U	0.38	0.27

Table 7-6 Example of Mputa properties for H15U from PRR

7.3.2.3 In place volumes

TRACS carried out a high level review of the inputs to Tullow's volumetric estimates. Upon review of the structure maps and contacts the GRV in the Mputa PRR was judged to be slightly pessimistic and were increased by around 10%-20% with the ranges also widened. There were some updates to properties but generally the properties from the PRR were accepted.

The oil formation volume factor is taken to be 1.1for all zones and segments. Mputa has no gas cap.

The range of in-place volumes for oil and gas for Mputa is shown in Table 7-7. An average gas oil ratio of 206 scf/bbl has been used to estimate the solution gas volumes.

	Reservoirs/ areas	P10	P50	P90
STOIIP (MMbbls)	**Total oil**	**102.2**	**130.8**	**164.3**
GIIP (Bscf)	Solution gas	15.2	19.5	24.5
	Total gas	**15.2**	**19.5**	**24.5**

Table 7-7 Mputa STOIIP range

7.3.2.4 Analytical approach to CR assessment

The analytical approach for the various projects is outlined below.

Multiple projects (mainly waterflood)

Multiple projects are noted in a number of panels. Low, Mid and High case simulation models were provided by Tullow with a range of recovery factors. No reports were available. The simulation model recovery factors are lower than the Tullow CR recovery factor, although the latter also includes a polymer flood project.

Given the limited data the only auditable values are those from the models, which have a reasonable range and are summarised below.

The range of recovery factors for 50 years for Mputa are presented in Table 7-8.

Field	**Project**		**TRACS**
			Rf 50 yrs
Mputa	Multiple projects	L	0.10
		M	0.15
		H	0.17

Table 7-8 Mputa Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

7.3.3 Estimation of Mputa Contingent Resources

7.3.3.1 Contingent Resources Development Pending

No CR Development Pending resources has been identified for Mputa

7.3.3.2 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Mputa. This has been carried as DoH for oil and (solution) gas. The results are presented in section 7.3.4.

7.3.3.3 Contingent Resources Development not Viable

There are no resources in this category since Mputa does not have a gas cap.

7.3.4 Mputa CR summary

The total Contingent Resources for the Mputa field are presented in Table 7-9for oil resources and Table 7-10 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development on Hold	10.7	19.0	28.6	3.0	5.4	8.1
Total All CR Categories	**10.7**	**19.0**	**28.6**	**3.0**	**5.4**	**8.1**

Table 7-9 Mputa Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.8	1.4	2.1	0.2	0.4	0.6
Total All CR Categories	**0.8**	**1.4**	**2.1**	**0.2**	**0.4**	**0.6**

Table 7-10 Mputa Gas Contingent Resource summary

7.4 NZIZI FIELD

7.4.1 FIELD BACKGROUND / INTRODUCTION

Field Name	**Nzizi**
Location	Albert Basin Area EA-2
Tullow working interest	Currently 33.33%. After UNOC buy-in: 28.33%
Operator	Tullow
Geology	The reservoirs are good quality, high permeability sands of Miocene/Pliocene age deposited in a fluvial/lacustrine deltaic setting. The field consists of fault-bound panels in a structural trap (dip and fault closure).
HCIIP estimate	Oil GIIP P90 – 36 MMstb 13 Bscf P50 – 34 MMstb 16 Bscf P10 – 43 MMstb 13 Bscf
Development type	Depletion
Number of current production & injection wells	3 E&A wells
Cumulative production to end 2019	Not yet on production.
Current recovery factor (based on 2C STOIIP)	Not yet on production.
Plans for further development	Not yet on production.

7.4.2 Contingent Resources

7.4.2.1 Geoscience review and in place volumes

Introduction

The Nzizi Field lies on the eastern shores of Lake Albert, 5km southwest of Mputa, and is divided into five fault panels, three of which have been penetrated by wells, see Figure 7-3. There are five main reservoir packages, three gas bearing and two oil bearing:

- Upper H30: oil
- H30: gas
- H20: gas
- H15: gas
- Lower H10: oil

The Nzizi reservoirs are interpreted to be fluvio-deltaic channel sands and channel mouth bars interbedded with claystones of fluvial/lacustrine origin. The channel bodies appear to be isolated and encased in mud.

The stratigraphy and structural history of Nzizi are similar to Mputa. As with Mputa, Nzizi lies close to the breach point of the Kaiso-Tonya relay ramp. As such the area has undergone complex movement leading to a highly compartmentalised structure.

The hydrocarbon distribution is complex with fluid levels varying both laterally and vertically to give a series of stacked pools.

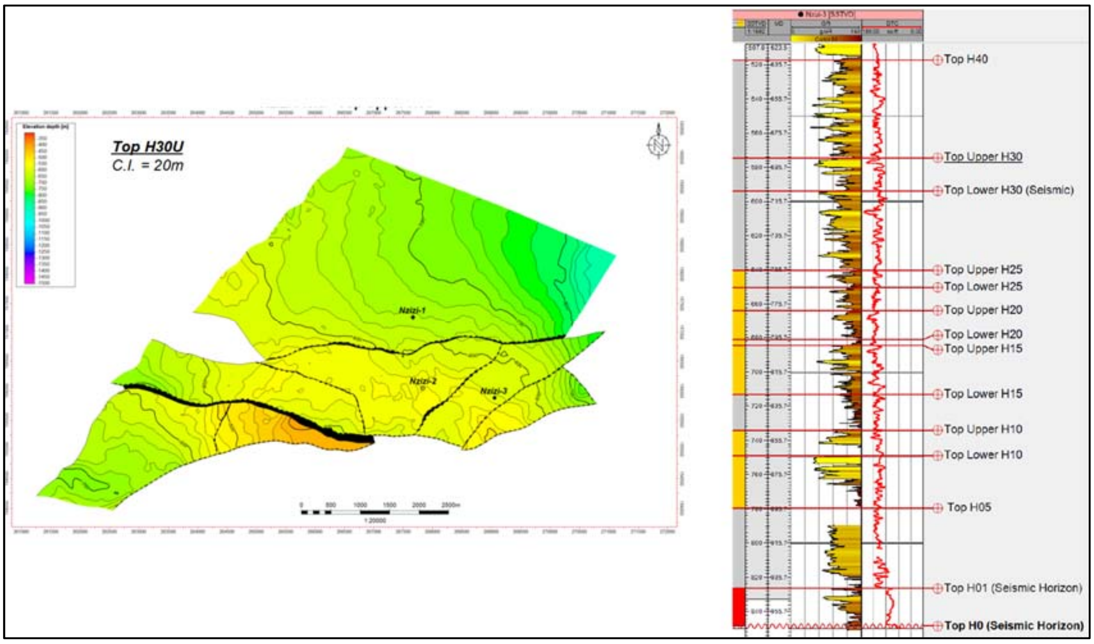


Figure 7-3 Nzizi depth map and Nzizi-3 well

The petrophysical description is accepted as is.

In place volumes

The Nzizi Field carries low Contingent Resources and, therefore, was not reviewed in detail. TRACS carried out a high level review of the inputs to Tullow's volumetric estimates. The GRVs were based on the supplied structure maps and guided by the 2016 PRR.

Generally the properties were accepted but the ranges widened.

The range of in-place volumes for oil and gas for Nzizi is shown in Table 7-11An average gas oil ratio of 200 scf/bbl has been used to estimate the solution gas volumes. Some Nzizi reservoirs are gas bearing. The gas expansion factor used for these reservoirs is 65 v/v.

	Reservoirs/ areas	**P10**	**P50**	**P90**
STOIIP (MMbbls)	**Field**	**25.6**	**33.7**	**43.4**
GIIP (Bscf)	Solution gas	5.1	6.7	8.7
	Free gas	7.7	9.7	13.3
	Total gas	**12.8**	**16.4**	**22.0**

Table 7-11 Nzizi STOIIP range

7.4.2.2 Analytical approach to CR assessment

No models or reports were provided; the recovery factors in the table below are taken from the PRR. These values appear to be consistent with high viscosity (40cp) and low areal sweep efficiency. No further evaluation was performed owing to the small size of the field.

The range of recovery factors for 50 years for Nzizi are presented in Table 7-12.

Field	**Project**		**TRACS**
			Rf 50 yrs
Nzizi	Waterflood	L	0.04
		M	0.06
		H	0.06

Table 7-12 Nzizi Recovery Factors

No production profiles were generated for this project as a commerciality test was not required.

The gas recovery factors follow the same approach as Jobi Rii (section 4.2.2.4).

7.4.3 Estimation of Nzizi Contingent Resources

7.4.3.1 Contingent Resources Development on Hold

Oil and gas

A waterflood development has been identified as a possible future development for Nzizi. This has been carried as DoH for oil and (solution) gas. The results are presented in section 7.4.4.

7.4.3.2 Contingent Resources Development not Viable

The development of the gas bearing reservoirs in Nzizi are carried as DnV as potentially additional facilities will be needed to develop the gas and this has not been studied or feasibility tested.

7.4.4 Nzizi CR summary

The total Contingent Resources for the Nzizi field are presented in Table 7-13for oil resources and Table 7-14 for gas resources.

CR Oil	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
	1C	2C	3C	1C	2C	3C
Development on Hold	1.0	2.0	3.0	0.3	0.6	0.9
Total All CR Categories	**1.0**	**2.0**	**3.0**	**0.3**	**0.6**	**0.9**

Table 7-13 Nzizi Oil Contingent Resource summary

CR Gas	Gross (Bscf)			Tullow Working Interest (Bscf)		
	1C	2C	3C	1C	2C	3C
Development on Hold	0.1	0.2	0.3	0.0	0.1	0.1
Development not Viable	3.9	6.3	10.6	1.1	1.8	3.0
Total All CR Categories	**4.0**	**6.5**	**10.9**	**1.1**	**1.8**	**3.1**

Table 7-14 Nzizi Gas Contingent Resource summary

8 UGANDA SUMMARY OF RESOURCES

Sections 4 to 7 have presented unrisked resources by field for the Uganda assets and categorised the resources based on 2018 SPE PRMS. All resources have been classified as contingent resources but they carry different levels of risk with respect to how likely the resources will ultimately become developed and then be classified as reserves. In order to assess the likelihood of maturing into commercial projects Chances of Commerciality (CoCs) have been assessed for all contingent resources, which are then applied to the CR values to obtain risked resources.

8.1 CHANCE OF COMMERCIALITY

A CoC for the Phase 1 project has been assessed and presented in Section 4.1.3. It is estimated at 50% and all resources associated with this COC are classified as Development Pending. All remaining resources in the Ugandan fields (post Phase 1) require the Phase 1 project to be in place before further development of resources goes ahead. Consequently the COC of all remaining projects and associated resources cannot be higher than 50%.

A COC has been estimated for the following split of resources to give transparency to the risking:

- Phase 1 (DP CR)
- Polymer flood for Phase 1 fields (DoH CR)
- Remaining oil resources after Phase 1 and polymer flood (DoH CR)
- Solution gas resources associated with capturing the gas from the oil developments (DoH CR)
- Development of gas caps in the Uganda fields (DnV CR)

Polymer flooding of the Phase 1 fields has significant estimated resources associated with it. It has been extensively studied and at one stage was considered as part of the Phase 1 project. Further studies and a pilot development are planned to further investigate the potential of polymer flooding. It is considered likely that polymer flooding will be implemented if the Phase project goes ahead. This is therefore given an incremental CoC of 75% which results in a total CoC for the project of 37.5% (75% * 50%).

The remaining oil in the Uganda fields is significant but has more challenges to develop it than the Phase 1 fields and reservoirs. The incremental CoC for these resources is estimated at 50% which results in a total CoC of 25% (50%*50%).

The solution gas resources (mainly associated with Phase 1 fields) will be produced if the oil is produced but there are currently no firm plans associated with Phase 1 to monetise the gas. Possible solutions have been studied and will continue to be investigated (e.g. supplying a gas power plant). The likelihood of a gas solution being developed to monetise the gas once Phase 1 is in place is estimated to be 50% giving a total CoC of 25% (50%*50%).

The volumes associated with developing the gas caps in the Uganda fields are relatively small. However if there is a gas solution in place then there is a possibility that they may be developed. The incremental COC that they will be developed is estimated at 25% (accounting for the fact that a gas solution needs to be in place) giving a total CoC of 12.5% (50%*25%).

Table 8-1 gives a summary of the CoCs by project.

Project	Category	Chance of Commerciality
Phase 1	Development Pending	50%
Polymer flood	Development on Hold	37.5%
Remaining Oil	Development on Hold	25%
Solution gas development	Development on Hold	25%
Gas cap development	Development not viable	12.5%

Table 8-1 Summary of COCs

8.2 SUMMARY OF UNRISKED RESOURCES

The total remaining Gross and Working Interest to Tullow unrisked Contingent Resources for Uganda is given for oil in Table 8-2, for gas in Table 8-3 and total (boe) in Table 8-4. A conversion rate of 167 boe/MMscf is assumed. The Working Interest resources to Tullow are based on a 28.33% share of the Gross CR. The CoC is presented in the table but has not been applied to the resources.

CR Classification (Oil)	Project	Gross (MMbbls)			Tullow Working Interest (MMbbls)			CoC
		1C	2C	3C	1C	2C	3C	
Development Pending	Phase 1	555.9	910.0	1436.6	157.5	257.8	407.0	50.0%
Development on Hold	Polymer flood	184.3	292.7	462.3	52.2	82.9	131.0	37.5%
Development on Hold	Remaining oil	212.6	445.9	736.4	60.2	126.3	208.6	25.0%
Total All CR Categories		**952.8**	**1648.6**	**2635.3**	**269.9**	**467.1**	**746.6**	

Table 8-2 Tullow Uganda Contingent Resource summary – Oil Unrisked

CR Classification (Gas)	Project	Gross (Bscf)			Tullow Working Interest (Bscf)			CoC
		1C	2C	3C	1C	2C	3C	
Development on Hold	Solution gas	83.2	138.9	223.3	23.6	39.3	63.2	25.0%
Development not Viable	Gas caps	28.1	53.2	91.4	8.0	15.1	25.9	12.5%
Total All CR Categories		**111.3**	**192.1**	**314.6**	**31.5**	**54.4**	**89.1**	

Table 8-3 Tullow Uganda Contingent Resource summary – Gas Unrisked

CR Classification (Total)	Project	Gross (MMboe)			Tullow Working Interest (MMboe)			CoC
		1C	2C	3C	1C	2C	3C	
Development Pending	Phase 1	555.9	910.0	1436.6	157.5	257.8	407.0	50.0%
Development on Hold	Polymer flood	184.3	292.7	462.3	52.2	82.9	131.0	37.5%
Development on Hold	Remaining oil	212.6	445.9	736.4	60.2	126.3	208.6	25.0%
Development on Hold	Solution gas	13.9	23.1	37.2	3.9	6.6	10.5	25.0%
Development not Viable	Gas caps	4.7	8.9	15.2	1.3	2.5	4.3	12.5%
Total All CR Categories		**971.4**	**1680.6**	**2687.7**	**275.2**	**476.1**	**761.4**	

Table 8-4 Tullow Uganda Contingent Resource summary – Total boe Unrisked

8.3 SUMMARY OF RISKED RESOURCES

In this section the CoCs have been applied to the unrisked CR to generate risked Contingent Resources. These are presented in Table 8-5, Table 8-6 and Table 8-7 for oil, gas and total boe, respectively.

CR Classification (Oil)	Project	Gross (MMbbls)			Tullow Working Interest (MMbbls)		
		1C	2C	3C	1C	2C	3C
Development Pending	Phase 1	278.0	455.0	718.3	78.7	128.9	203.5
Development on Hold	Polymer flood	69.1	109.8	173.4	19.6	31.1	49.1
Development on Hold	Remaining oil	53.2	111.5	184.1	15.1	31.6	52.2
Total All CR Categories		**400.2**	**676.2**	**1075.8**	**113.4**	**191.6**	**304.8**

Table 8-5 Tullow Uganda Contingent Resource summary – Oil Risked

CR Classification (Gas)	Project	Gross (Bscf)			Tullow Working Interest (Bscf)		
		1C	2C	3C	1C	2C	3C
Development on Hold	Solution gas	20.8	34.7	55.8	5.9	9.8	15.8
Development not Viable	Gas caps	3.5	6.7	11.4	1.0	1.9	3.2
Total All CR Categories		**24.3**	**41.4**	**67.2**	**6.9**	**11.7**	**19.0**

Table 8-6 Tullow Uganda Contingent Resource summary – Gas Risked

CR Classification (Total)	Project	Gross (MMboe)			Tullow Working Interest (MMboe)		
		1C	2C	3C	1C	2C	3C
Development Pending	Phase 1	278.0	455.0	718.3	78.7	128.9	203.5
Development on Hold	Polymer flood	69.1	109.8	173.4	19.6	31.1	49.1
Development on Hold	Remaining oil	53.2	111.5	184.1	15.1	31.6	52.2
Development on Hold	Solution gas	3.5	5.8	9.3	1.0	1.6	2.6
Development not Viable	Gas caps	0.6	1.1	1.9	0.2	0.3	0.5
Total All CR Categories		**404.3**	**683.1**	**1087.0**	**114.5**	**193.5**	**307.9**

Table 8-7 Tullow Uganda Contingent Resource summary – Total boe Risked

9 GLOSSARY OF TERMS

LR13.4.6(2)

$	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
Capex	capital expenditure
CGR	Condensate Gas Ratio
cm^3	cubic centimetre
m^3	cubic metre
COC	Chance of Commerciality
COP	Cessation of Production
CPF	Central Processing Facility
Den	Density log
DST	Drill Stem Test
DT	Sonic log
ft	feet
EPS	Export Pipeline System
FID	Final Investment Decision
FWL	Free Water Level
G & G	Geological and Geophysical
GDT	Gas Down To
GIIP	Gas Initially In Place
GOR	Gas to Oil Ratio
GRV	Gross Rock Volume
GWC	Gas Water Contact
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
N/G	Net to Gross
NFA	No Further Activity
ODT	Oil Down To
Opex	operating expenditure
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
PSC	Production Sharing Contract
psi	pounds per square inch
psia	pounds per square inch absolute
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
SPE	Society of Petroleum Engineers
sq km	square kilometres
ss	subsea
STOIIP	Stock Tank Oil Initially In Place
Sw	water Saturation
Swavg	average water Saturation
Sxo	water Saturation in invaded zone

TD	Total Depth
tvd	true vertical depth
tvdss	true vertical depth subsea
tvt	true vertical thickness
WI	Working Interest

Appendix A Production Profiles for Development Pending

Year	EA-1 Phase 1 Fields		
	1C Oil Mstbd	2C Oil Mstbd	3C Oil Mstbd
2023	103.6	130.1	136.1
2024	118.3	138.6	137.3
2025	111.8	139.2	139.2
2026	86.3	137.9	140.4
2027	67.1	130.6	140.8
2028	57.1	110.7	140.6
2029	49.2	94.4	140.4
2030	43.1	83.0	141.7
2031	38.3	74.1	146.9
2032	35.4	67.0	147.9
2033	31.9	60.9	133.5
2034	29.1	55.6	121.1
2035	26.6	51.0	111.2
2036	24.6	48.5	103.2
2037	22.8	45.0	95.8
2038	21.5	41.5	89.6
2039	20.1	38.6	85.1
2040	18.7	36.3	80.9
2041	17.5	34.3	77.2
2042	16.4	32.3	73.7
2043	15.5	30.7	70.0
2044	14.6	29.6	67.0
2045	13.8	28.1	64.4
2046	13.0	26.6	61.7

Table A-1 Developed Pending EA-1 Production Forecasts

Year	EA-2 Phase 1 Fields		
	1C Oil Mstbd	2C Oil Mstbd	3C Oil Mstbd
2023	30.8	41.7	42.4
2024	40.0	51.4	52.8
2025	40.0	50.8	50.9
2026	35.5	52.1	49.6
2027	26.9	51.3	49.3
2028	19.1	35.0	49.4
2029	15.1	26.3	49.6
2030	12.6	21.2	48.3
2031	10.6	17.8	43.1
2032	8.9	15.1	38.2
2033	8.2	13.1	31.7
2034	7.3	11.8	26.9
2035	6.5	10.7	23.4
2036	5.9	10.1	20.8
2037	5.4	9.0	19.0
2038	4.9	8.2	17.5
2039	4.5	7.5	15.6
2040	4.1	6.8	14.3
2041	3.7	6.3	13.3
2042	3.3	5.8	12.5
2043	3.1	5.4	11.8
2044	2.8	5.0	11.4
2045	2.7	4.8	11.0
2046	2.5	4.3	10.5

Table A-2 Developed Pending EA-2 Production Forecasts

Year	EA-3 Kingfisher Main Field		
	1C Oil Mstbd	2C Oil Mstbd	3C Oil Mstbd
2023	18.7	20.0	20.0
2024	30.0	30.0	30.0
2025	30.9	40.0	40.0
2026	26.7	38.9	40.0
2027	20.5	35.7	40.0
2028	14.8	32.1	40.0
2029	11.2	25.7	40.0
2030	9.3	20.4	40.0
2031	8.0	16.5	39.9
2032	6.9	13.8	38.9
2033	6.1	12.2	33.9
2034	5.5	10.8	28.9
2035	5.0	9.7	25.2
2036	4.7	8.8	22.4
2037	4.5	8.1	20.2
2038	4.2	7.4	17.6
2039	3.9	6.9	16.0
2040	3.8	6.5	14.8
2041	3.5	6.1	13.8
2042	3.2	5.9	12.9

Table A-3 Developed Pending EA-3 (Kingfisher) Production Forecasts

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

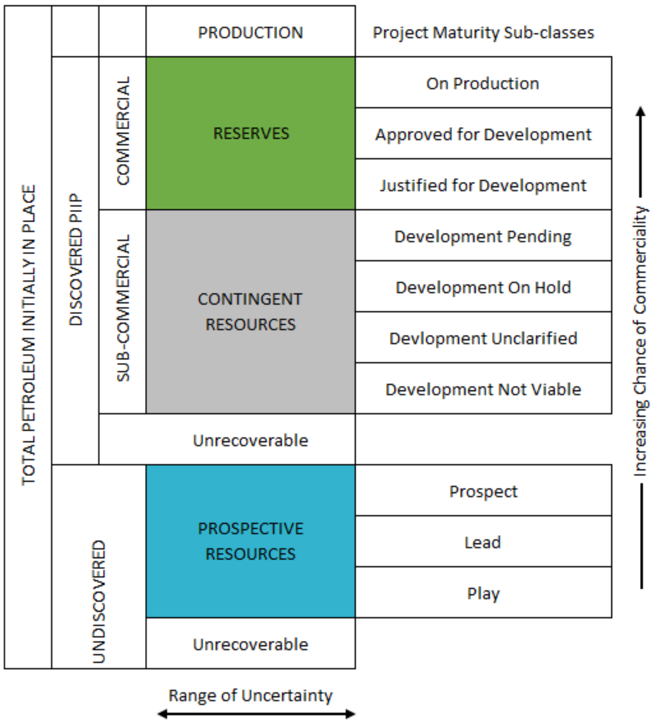


Table B-2 SPE PRMS Petroleum Resources Classification Framework

PART VIII—DEFINITIONS

The following definitions apply throughout this document unless the context requires otherwise:

"2015 Settlement"	has the meaning given to it in Section 9.2(b) of Part VI (*Additional Information)*
"2017 Uganda Assets Farm-down"	Tullow Uganda's proposed farm-down of its assets in Uganda to Total Uganda announced on 9 January 2017
"2017 Uganda Sale Assets"	has the meaning given to it in Section 8.2(b) of Part VI (*Additional Information*)
"2022 Senior Notes"	has the meaning given to it in Section 8.1(g) of Part VI (*Additional Information*)
"2025 Senior Notes"	has the meaning given to it in Section 8.1(i) of Part VI (*Additional Information*)
"Adjusted EBITDAX" . . .	has the meaning given to it on page 5
"Agents"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"AOE"	has the meaning given to it in Section 9.1(b) of Part VI (*Additional Information*)
"ARA"	has the meaning given to it in Section 8.1(c) of Part VI (*Additional Information*)
"Articles"	the articles of association of the Company
"Barclays"	Barclays Bank PLC, acting through its investment bank and incorporated in England and Wales with registered number 01026167 and whose registered address is 1 Churchill Place, London, E14 5HP
"bbl"	standard barrel, being the equivalent of 42 US gallons
"bcf"	billions of cubic feet
"Block 2 North"	the development areas in the northern part of Block 2 licensed under the following petroleum production licences: Petroleum Production Licence 01/2016 in relation to the Kasamene-Wahrindi development area; Petroleum Production Licence 02/2016 in relation to the Kigogole-Ngara development area; Petroleum Production Licence 03/2016 in relation to the Nsoga development area; and Petroleum Production Licence 04/2016 in relation to the Ngege development area
"Block 2 South"	the development areas in the southern part of Block 2 licensed under the Petroleum Production Licence 05/2016 in relation to the Mputa-Nzizi and Waraga development area
"Board"	the board of Directors of the Company
"Bond Guarantors"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Bond Issuer"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Business Review"	the Company's business review as initially disclosed in the Company's announcement of 9 December 2019 of board changes and revisions to 2020 guidance and the results of which were disclosed in the Company's 2019 Full Year Results on 12 March 2020
"Calculation Agent"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"CGT"	has the meaning given to it in Section 3 of Part II (*Risk Factors*)

"CNOOC Uganda"	CNOOC Uganda Limited
"Completion"	Completion in accordance with the provisions of the Sale and Purchase Agreement
"Consolidated EBITDA"	has the meaning given to it in Section 19 of Part I (*Letter from the Executive Chair of Tullow*)
"Conversion Right"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Agency Agreement"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Calculation Agency Agreement"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Deed Poll"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bonds"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Subordination Agreement"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Subscription Agreement"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Terms and Conditions"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Convertible Bond Trust Deed"	has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)
"Corporate Facility"	has the meaning given to it in Section 8.1(e) of Part VI (*Additional Information*)
"Corporate Facility Agreement"	has the meaning given to it in Section 8.1(e) of Part VI (*Additional Information*)
"Covenanted Net Debt"	has the meaning given to it in Section 19 of Part I (*Letter from the Executive Chair of Tullow*)
"CREST"	the UK-based system for the paperless settlement of trades in listed securities, of which Euroclear UK & Ireland Limited is the operator in accordance with the Uncertificated Securities Regulations 2001 (SI 2001/3755)
"CREST Manual"	the manual, as amended from time to time, produced by Euroclear UK & Ireland Limited describing the CREST system, and supplied by Euroclear UK & Ireland Limited to users and participants thereof
"CREST Proxy Instruction"	has the meaning given to it in Part IX (*Notice of General Meeting)*
"Deloitte"	Deloitte LLP, Statutory Auditors, 2 New St Square, London, EC4A 3BZ
"Directors"	the Executive Directors and Non-Executive Directors of the Company

"Disclosure and Transparency Rules"	the Disclosure Guidance and Transparency Rules made by the FCA for the purposes of Part VI of FSMA
"DSBP"	has the meaning given to it in Section 11.3 of Part VI (*Additional Information*)
"EACOP System"	the East African Crude Oil Pipeline System
"Effective Date"	1 January 2020
"ESAP"	has the meaning given to it in Section 11.2 of Part VI (*Additional Information*)
"ESIA"	Environmental and Social Impact Assessment
"ESOP"	has the meaning given to it in Section 11.3 of Part VI (*Additional Information*)
"Euronext Dublin"	The Irish Stock Exchange plc, trading as Euronext Dublin
"Executive Chair"	Dorothy Thompson CBE, the executive chair of the Company
"Executive Directors"	the executive Directors of the Company, being currently Dorothy Thompson CBE and Les Wood
"FCA"	the Financial Conduct Authority of the UK, its predecessors or its successors from time to time, including, as applicable, in its capacity as the competent authority for the purposes of Part VI of FSMA
"FEED"	Front End Engineering Design
"Form of Proxy"	the form of proxy in connection with the General Meeting, which accompanies this document
"FPSO"	has the meaning given to it in Section 8.1(l) of Part VI (*Additional Information*)
"FPSO Contractor"	has the meaning given to it in Section 8.1(l) of Part VI (*Additional Information*)
"Free Shares"	has the meaning given to it in Section 11.3(a) of Part VI (*Additional Information*)
"FSMA"	the Financial Services and Markets Act 2000, as amended
"Gearing"	has the meaning given to it on page 5
"General Meeting"	the general meeting of the Company, notice of which is set out in the Notice of General Meeting in Part IX (*Notice of General Meeting*) of this document
"Global Commitments"	has the meaning given to it in Section 8.1(c) of Part VI (*Additional Information*)
"Good Leaver Reasons"	has the meaning given to it in Section 11.1 of Part VI (*Additional Information*)
"Government of Uganda"	the Government of the Republic of Uganda
"GRA"	Ghana Revenue Authority
"GRA Assessments"	has the meaning given to it in Section 9.1(b) of Part VI (*Additional Information*)
"Guarantee Subordination Agreement"	has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)
"Hedging Banks"	has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)
"Hitec"	HitecVision V, a Norwegian private equity company
"ICC"	the International Chamber of Commerce

"IFC Senior Secured Revolving Credit Facility Agreement"	has the meaning given to it in Section 8.1(d) of Part VI (*Additional Information*)
"IFRS"	the International Financial Reporting Standards, as adopted by the European Union
"Interests"	the entirety of Tullow's interests in each of the assets comprising the Lake Albert Development Project in Uganda, comprising: (i) a 33.3334 per cent. interest in the production sharing agreements for each of Block 1, 1A, 2 and 3A in Uganda and the licences and certain other contracts related thereto; and (ii) its interests in the proposed EACOP System, in each case as identified in the Sale and Purchase Agreement
"Irish Listing Rules"	Book I: Harmonised Rules of the Euronext Rule Book and Book II: Listing Rules of Euronext Dublin, taken together
"Irish SIP"	has the meaning given to it in Section 11.3 of Part VI (*Additional Information*)
"Joint Financial Advisers"	Barclays, J.P. Morgan Cazenove and Robey Warshaw, each in their capacity as joint financial adviser to Tullow in relation to the Transaction
"Joint Operating Agreements"	the joint operating agreements applicable to the Block 1, Block 1A, Block 2 and Block 3A licenced areas in the Lake Albert Rift Basin in Uganda
"Joint Sponsors"	Barclays and J.P. Morgan Cazenove, each in their capacity as joint sponsor to Tullow in relation to the Transaction
"J.P. Morgan Cazenove"	J.P. Morgan Securities plc (which conducts its UK investment banking business as J.P. Morgan Cazenove)
"Kingfisher Development"	means the development of the Kingfisher field located in the Kingfisher Discovery Area covered by a production licence issued in February 2012, the wells and flowlines connecting to a central processing facility (and associated facilities) located in Block 3, the water abstraction infrastructure from Lake Albert, together with a 14" export feeder pipeline connecting to the proposed EACOP System, possible refinery and shared facilities to be located at Kabaale
"Lake Albert Development Project"	the Upstream Segment and the Midstream Segment
"Latest Practicable Date"	15 June 2020
"LC Exposure"	has the meaning given to it in Section 8.1(c) of Part VI (*Additional Information*)
"Liquidity Forecast Test"	has the meaning given to it in Section 19 of Part I (*Letter from the Executive Chair of Tullow*)
"Listing Rules"	the Listing Rules made by the FCA for the purposes of Part VI of FSMA
"London Stock Exchange"	London Stock Exchange PLC, of 10 Paternoster Square, London, EC4M 7LS
"Matching Shares"	has the meaning given to it in Section 11.3(c) of Part VI (*Additional Information*)
"Maximum Available Amount"	has the meaning given to it in Section 8.1(c) of Part VI (*Additional Information*)
"Midstream Segment"	has the meaning given to it in Section 3 of Part I (*Letter from the Executive Chair of Tullow*)
"Minister Consents"	has the meaning given to it in Section 3 of Part I (*Letter from the Executive Chair of Tullow*)
"mmbbl"	standard millions of barrels (a barrel being the equivalent of 42 US gallons)

"mmboe" . . . . standard millions of barrels of oil equivalent (a barrel being the equivalent of 42 US gallons)

"Net Debt" . . . . has the meaning given to it on page 5

"Non-Executive Directors" the non-executive Directors of the Company, being currently Jeremy Wilson, Mike Daly, Sheila Khama, Genevieve Sangudi and Martin Greenslade

"Notes Creditors" . . . . . . has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)

"Notes Guarantee Liabilities" . . . . has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)

"Notice" . . . . has the meaning given to it in Part IX *(Notice of General Meeting)*

"Notice of Dispute" . . . . . has the meaning given to it in Section 9.1(b) of Part VI (*Additional Information*)

"Notice of General Meeting" . . . . the notice of the General Meeting, as set out in Part IX (*Notice of General Meeting*) of this document

"O&M Period" . . . . has the meaning given to it in Section 8.1(l) of Part VI (*Additional Information*)

"Parent Bond Guarantor" has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)

"Partnership Shares" . . . . has the meaning given to it in Section 11.3(b) of Part VI (*Additional Information*)

"PL537" . . . . has the meaning given to it in Section 9.1(c) of Part VI (*Additional Information*)

"PRA" . . . . the Prudential Regulation Authority

"Preference Shareholder" . has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)

"Preference Shares" . . . . has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)

"PR Regulation" . . . . Commission Delegated Regulation (EU) 2019/980 of 14 March 2019 supplementing Regulation (EU) 2017/1129 of the European Parliament and of the Council as regards the format, content, scrutiny and approval of the prospectus to be published when securities are offered to the public or admitted to trading on a regulated market, and repealing Commission Regulation (EC) No 809/2004

"PRMS" . . . . Petroleum Resources Management System

"RBL Creditors" . . . . . . has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)

"RBL Facility" . . . . has the meaning given to it in Section 8.1(c) of Part VI (*Additional Information*)

"RBL Facility Agreement" has the meaning given to it in Section 8.1(c) of Part VI (*Additional Information*)

"RBL Gearing Covenant" has the meaning given to it in Section 19 of Part I (*Letter from the Executive Chair of Tullow*)

"RBL Lender Intercreditor Agreement" . . . . has the meaning given to it in Section 8.1(f) of Part VI (*Additional Information*)

"Registrars" . . . . Computershare Investor Services plc and The Central Securities Depository (Ghana) Limited

"Remuneration Committee" . . . . has the meaning given to it in Section 11.1 of Part VI (*Additional Information*)

"Resolution" . . . . the resolution being proposed at the General Meeting to approve the Transaction and to grant the Directors authority to implement the Transaction

"Retained Group" . . . . . . the Company and its subsidiaries and subsidiary undertakings from time to time (excluding, for the avoidance of doubt, the Interests after Completion), being the continuing business of the Tullow Group following Completion

"RIS" . . . . a Regulatory Information Service that is approved by the FCA and that is on the list of Regulatory Information Services maintained by the FCA

"Robey Warshaw" . . . . . Robey Warshaw LLP

"Sale and Purchase Agreement" . . . . the sale and purchase agreement dated 23 April 2020 entered into between Tullow Uganda Limited, Tullow Uganda Operations Pty Ltd, the Company and Total E&P Uganda B.V. in connection with the sale of the Interests, as described in more detail in Part V (*Summary of the Principal Terms of the Transaction*) of this document

"Senior Creditors" . . . . . has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)

"Senior Discharge Date" . has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)

"Senior Liabilities" . . . . . has the meaning given to it in Section 8.1(j) of Part VI (*Additional Information*)

"Shareholders" . . . . the holders of Tullow Shares from time to time

"SIP" . . . . has the meaning given to it in Section 11.3 of Part VI (*Additional Information*)

"SPE" . . . . the Society of Petroleum Engineers

"Sponsors' Agreement" . . has the meaning given to it in Section 8.1(b) of Part VI (*Additional Information*)

"Spring" . . . . Spring Energy Norway AS

"Spring SPA" . . . . has the meaning given to it in Section 9.1(c) of Part VI (*Additional Information*)

"Subordinated Guarantee" has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)

"Subsidiary Bond Guarantors" . . . . has the meaning given to it in Section 8.1(h) of Part VI (*Additional Information*)

"Tax Agreement" . . . . . . has the meaning given to it in Section 3 of Part I (*Letter from the Executive Chair of Tullow*)

"TEN FPSO Contract" . . has the meaning given to it in Section 8.1(l) of Part VI (*Additional Information*)

"TEN O&M Contract" . . has the meaning given to it in Section 8.1(l) of Part VI (*Additional Information*)

"**Tilenga Development**" . . . means the development of the nine fields (located in Block 1 and Block 2) covered by three production licences in Block 1 (covering Ngiri, Jobi Rii and Gunya fields) and four production licences in Block 2 (covering Kigogole Ngara, Nsoga, Ngege and Kasamene-Wahrindi Fields) issued in June 2016, the wells, flowlines connecting the fields to a central processing facility (and associated facilities) located in Block 1, the water abstraction infrastructure

	from Lake Albert, together with the 24" export feeder pipeline connecting to the proposed EACOP System, possible refinery and shared facilities located at Kabaale
"TIP"	has the meaning given to it in Section 11.1 of Part VI (*Additional Information*)
"TOH"	has the meaning given to it in Section 9.1(c) of Part VI (*Additional Information*)
"Total"	Total SA
"Total Holdings"	Total Holdings S.A.S.
"Total Uganda"	Total E&P Uganda B.V.
"TRACS"	TRACS International Limited
"TRACS Report"	has the meaning given to it on page 3
"Transaction"	the sale of the Interests pursuant to the Sale and Purchase Agreement
"Transaction Agreements"	the Sale and Purchase Agreement, the Tax Agreement, the Tullow guarantee in respect of the Interests and the Total Holdings guarantee in respect of the Interests
"Transaction Announcement"	the announcement of the Transaction made by the Company on 23 April 2020
"Tullow" or "Company"	Tullow Oil plc, incorporated in England and Wales with registered number 03919249 and whose registered office is at 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT
"Tullow Ghana"	Tullow Ghana Limited
"Tullow Group" or "Group"	in respect of any time prior to Completion, the Company and its consolidated subsidiaries and subsidiary undertakings and, in respect of any time following Completion, the Retained Group
"Tullow Shares"	the ordinary shares of 10 pence each in the capital of the Company
"Tullow Uganda"	Tullow Uganda Limited and Tullow Uganda Operations Pty Ltd.
"UK"	the United Kingdom of Great Britain and Northern Ireland
"UNOC"	Uganda National Oil Company
"Upstream Segment"	has the meaning given to it in Section 3 of Part I (*Letter from the Executive Chair of Tullow*)
"URA"	Uganda Revenue Authority
"Vallourec"	Vallourec Oil and Gas France
"VAT"	has the meaning given to it in Section 3 of Part II (*Risk Factors*)
"Working Capital Period"	has the meaning given to it in Section 13 of Part VI (*Additional Information*)

PART IX—NOTICE OF GENERAL MEETING

Tullow Oil plc (the "**Company**") *(Company number 03919249)*

Notice of General Meeting

Notice is hereby given that a General Meeting of the Company will be held at the offices of Tullow Oil plc, at 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT on 15 July 2020 at 12 noon (London time) to consider and, if thought fit, to pass the resolution set out below, which shall be proposed as an ordinary resolution, in connection with the proposed sale of the Interests (the "Transaction"), as described in the circular to Tullow Shareholders dated 18 June 2020 (the "Circular").

Capitalised terms used in this Notice of General Meeting (the "Notice") which are not defined herein shall have the meanings given to them in the Circular of which this Notice forms part.

Ordinary Resolution

THAT:

(a) the proposed sale by the Company of its entire interests in: (i) the production sharing agreements for Block 1, Block 1A, Block 2 and Block 3A in Uganda and the licences and certain other contracts related thereto; and (ii) the proposed East African Crude Oil Pipeline (EACOP) System and associated facilities, as described in the Circular and substantially on the terms and subject to the conditions of the agreement for the sale and purchase dated 23 April 2020 between Tullow Uganda Limited, Tullow Uganda Operations Pty Ltd, the Company and Total E&P Uganda B.V. (the "SPA") and all other agreements and ancillary documents contemplated by the SPA, be and are hereby approved for the purposes of Chapter 10 of the Listing Rules; and

(b) the directors of the Company (the "Directors") (or any duly authorised committee thereof) be and are hereby authorised to take all necessary, expedient or desirable steps and to do all necessary, expedient or desirable things to implement, complete or to procure the implementation or completion of the Transaction and any matters incidental to the Transaction and to give effect thereto with such modifications, variations, revisions, waivers or amendments (not being modifications, variations, revisions, waivers or amendments of a material nature by reference to Listing Rule 10.5.2) as the Directors (or any duly authorised committee thereof) may deem necessary, expedient or desirable in connection with the Transaction and any matters incidental to the Transaction.

By Order of the Board

Adam Holland
Company Secretary
18 June 2020

Registered Office:
9 Chiswick Park
566 Chiswick High Road
London
W4 5XT

Notes

Attending the General Meeting in person

In light of the social distancing measures aimed at reducing the transmission of the COVID-19 virus in the United Kingdom, please note that attendance at the General Meeting in person is not possible. The General Meeting will be a closed meeting. Shareholders should not attempt to attend the General Meeting in person. **Any Shareholders who attempt to attend in person will be refused entry. Shareholders should instead vote in advance by proxy** by appointing the Chair of the General Meeting as their proxy in respect of all of their shares to vote on their behalf.

Audio cast and General Meeting website

Continued Shareholder engagement remains very important to the Company and Shareholders will therefore be able to listen to a live audio-cast of the General Meeting and submit questions remotely throughout, as was possible for the Company's 2020 Annual General Meeting (please see detailed instructions below). Shareholders may also submit questions in advance via ir@tullowoil.com.

Shareholders can listen to the live audio-cast of the General Meeting as well as ask questions remotely by either downloading the dedicated "Lumi AGM" app or by accessing the General Meeting website, http://web.lumiagm.com.

To access the audio-cast and ask questions, you will need to download the latest version of the "Lumi AGM" app onto your smartphone from the Google Play Store™ or the Apple® App Store. The Company recommends that you do this in advance of the General Meeting. Please note that the app is not compatible with certain older devices. Alternatively, you can access the General Meeting using most well-known internet browsers such as Internet Explorer (versions 10 and 11), Chrome, Firefox and Safari on a PC, laptop or internet-enabled device such as a tablet or smartphone. If you wish to access the General Meeting using this method, please visit http://web.lumiagm.com on the day of the General Meeting.

Whether you use the app or the website, you will be asked to enter a meeting ID which is 133-058-592. You will then be prompted to enter your unique Shareholder Reference Number (SRN) and PIN. Your PIN and your Shareholder Reference Number, which starts with a C or G and is 10 digits long, is available on the email broadcast sent to you if you are an online user or on the Form of Proxy if you elected for hard copy mailing. Access to the General Meeting via the app or website, and the ability to submit questions, will be available from 11.00 a.m. (London time) on 15 July 2020. The meeting will formally start at 12 noon (London time).

The process of asking questions and accessing the General Meeting audio casting will be further explained within the application and located on the information page.

Please contact Computershare Investor Services PLC before 11.00 a.m. (London time) on 15 July 2020 on the shareholder helpline number: + 44 (0) 370 703 6242 (UK and other Shareholders) for your Shareholder Reference Number (SRN) and PIN. Lines are open 8.30 a.m. to 5.30 p.m. Monday to Friday (excluding UK public holidays). Shareholders should note that electronic entry to the General Meeting will open at 11.00 a.m. (London time) on 15 July 2020, and the meeting will formally start at 12 noon (London time).

Appointment of proxies

Members are entitled under the Company's articles of association to appoint one or more proxies to exercise all or any of their rights to attend, speak and vote at general meetings. However, as the General Meeting will be a closed meeting in light of the social distancing measures aimed at reducing the transmission of the COVID-19 virus in the United Kingdom, members should appoint the Chair of the Meeting as their proxy rather than any other individual(s). Due to the restrictions on physical attendance at the General Meeting, any other individual(s) will not be able to attend, speak or vote on members' behalf.

To be validly appointed, a proxy must be appointed using the procedures set out in these notes and in the notes to the accompanying Form of Proxy. A member may instruct their proxy to abstain from voting on any resolution to be considered at the General Meeting by marking the 'Vote Withheld' option when appointing their proxy. It should be noted that a vote withheld is not a vote in law and will not be counted in the calculation of the proportion of votes 'For' or 'Against' a resolution. A person who is not a member of the Company but who has been nominated by a member to enjoy information rights does not have a right to appoint any proxies under the procedures set out in these notes and should read the 'Nominated persons' paragraph below.

Appointment of a proxy online

As an alternative to appointing a proxy using the Form of Proxy or CREST, members can appoint a proxy online at: www.investorcentre.co.uk/eproxy. In order to appoint a proxy using this website, members will need their Control Number, Shareholder Reference Number and PIN. This information is printed on the Form of Proxy. If for any reason a member does not have this information, they will need to contact the Registrar in the UK by telephone on +44 (0) 370 703 6242 or by logging on to www.investorcentre.co.uk/contactus (UK and other Shareholders) or the Registrar in Ghana by telephone on +233 302 906 576 or via info@csd.com.gh. Members must appoint a proxy using the website no later than 48 hours (excluding any part of a day that is not a working day) before the time of the General Meeting or any adjournment of that meeting.

Appointment of a proxy using a Form of Proxy

A Form of Proxy for use in connection with the General Meeting is enclosed. To be valid, a Form of Proxy or other instrument appointing a proxy, together with any power of attorney or other authority under which it is signed or a certified copy thereof, must be returned to Tullow's Registrars: (i) in the UK, Computershare Investor Services PLC, The Pavilions, Bridgwater Road, Bristol, BS99 6ZY, as soon as possible and, in any event, so as to be received by no later than 48 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting or any adjournment of that meeting; or (ii) in Ghana, The Central Securities Depository (Ghana) Limited, 4th Floor, Cedi House, P.M.B CT 465 Cantonments, Accra, Ghana, as soon as possible and, in any event, so as to be received by no later than 72 hours (excluding any part of a day that is not a working day) before the time appointed for the holding of the General Meeting or any adjournment of that meeting. If you do not have a Form of Proxy and believe that you should have one, or you require additional Forms of Proxy, please contact the Registrar in the UK by telephone on +44 (0) 370 703 6242 or by logging on to www.investorcentre.co.uk/contactus (UK and other Shareholders) or the Registrar in Ghana by telephone on +233 302 906 576 or via info@csd.com.gh.

Appointment of a proxy through CREST

CREST members who wish to appoint a proxy through the CREST electronic proxy appointment service may do so by using the procedures described in the CREST Manual and by logging on to the following website: www.euroclear.com. CREST personal members or other CREST sponsored members, and those CREST members who have appointed (a) voting service provider(s), should refer to their CREST sponsor or voting service provider(s) who will be able to take the appropriate action on their behalf.

In order for a proxy appointment or instruction made using the CREST service to be valid, the appropriate CREST message (a "CREST Proxy Instruction") must be properly authenticated in accordance with Euroclear UK & Ireland Limited's specifications and must contain the information required for such instruction, as described in the CREST Manual. The message, regardless of whether it constitutes the appointment of a proxy or is an amendment to the instruction given to a previously appointed proxy must, in order to be valid, be transmitted so as to be received by Computershare Investor Services PLC (ID 3RA50) no later than 48 hours (excluding any part of a day that is not a working day) before the time of the General Meeting or any adjournment of that meeting. For this purpose, the time of receipt will be taken to be the time (as determined by the timestamp applied to the message by the CREST Application Host) from which Computershare Investor Services PLC is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST. After this time any change of instructions to proxies appointed through CREST should be communicated to the appointee through other means.

CREST members and, where applicable, their CREST sponsors or voting service provider(s) should note that Euroclear UK & Ireland Limited does not make available special procedures in CREST for any particular message. Normal system timings and limitations will, therefore, apply in relation to the input of CREST Proxy Instructions.

It is the responsibility of the CREST member concerned to take (or, if the CREST member is a CREST personal member, or sponsored member, or has appointed (a) voting service provider(s), to procure that their CREST sponsor or voting service provider(s) take(s)) such action as shall be necessary to ensure that a message is transmitted by means of the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting system providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Uncertificated Securities Regulations 2001 (as amended).

Appointment of proxy through Proxymity

Members who are institutional investors may be able to appoint a proxy electronically via the Proxymity platform, a process which has been agreed by the Company and approved by Computershare Investor Services PLC. For further information regarding Proxymity, please visit www.proxymity.io. Members must appoint a proxy via Proxymity by no later than 48 hours (excluding any part of a day that is not a working day) before the time of the General Meeting or any adjournment of that meeting. Before appointing a proxy via Proxymity, members will need to agree to Proxymity's associated terms and conditions. Members should read such terms and conditions carefully as they will be bound by such terms and conditions, which will govern the electronic appointment of their proxy.

Appointment of proxy by joint holders

In the case of joint holders, where more than one of the joint holders purports to appoint a proxy, only the purported appointment submitted by the most senior holder will be accepted. Seniority shall be determined by the order in which the names of the joint holders stand in the Company's register of members in respect of the joint holding.

Corporate representatives

Any corporation which is a member can appoint one or more corporate representatives. Members can only appoint more than one corporate representative where each corporate representative is appointed to exercise rights attached to different shares. Members cannot appoint more than one corporate representative to exercise the rights attached to the same share(s).

Entitlement to vote

To be entitled to vote at the General Meeting (and for the purpose of determining the votes they may cast), members must be registered in the Company's register of members at 6.00 p.m. (London time) on 13 July 2020 (or, if the General Meeting is adjourned, at 6.00 p.m. (London time) on the day which is two days (excluding non-working days) prior to the adjourned meeting). Changes to the register of members after the relevant deadline will be disregarded in determining the rights of any person to vote at the General Meeting.

Votes to be taken by a poll

At the General Meeting all votes will be taken by a poll. It is intended that the results of the poll votes will be announced to the London Stock Exchange and published on the Company's website as soon as possible after the conclusion of the General Meeting, and no later than 6.00 p.m. (London time) on 15 July 2020.

Nominated persons

Any person to whom this Notice is sent who is a person nominated under section 146 of the Companies Act 2006 ("the Act") to enjoy information rights (a "Nominated Person") may, under an agreement between them and the member by whom they were nominated, have a right to be appointed (or to have someone else appointed) as a proxy for the General Meeting.

If a Nominated Person has no such proxy appointment right or does not wish to exercise it, they may, under any such agreement, have a right to give instructions to the member as to the exercise of voting rights.

Website giving information regarding the General Meeting

Information regarding the General Meeting, including information required by section 311A of the Act, and a copy of this Notice of General Meeting is available from www.tullowoil.com.

Voting rights

As at 15 June 2020, being the latest practicable date prior to the publication of this Notice, the Company's issued share capital consisted of 1,410,844,261 Tullow Shares, carrying one vote each. No shares are held by the Company in treasury. Therefore, the total voting rights in the Company as at 15 June 2020 were 1,410,844,261 votes.

Notification of shareholdings

Any person holding three per cent. or more of the total voting rights of the Company who appoints a person other than the Chair of the General Meeting as their proxy will need to ensure that both they, and their proxy, comply with their respective disclosure obligations under the UK Disclosure Guidance and Transparency Rules. As at 15 June 2020, being the latest practicable date prior to the publication of this Notice, no notifications in respect of substantial shareholdings had been received other than as set out in Section 7 of Part VI (*Additional Information*) of the Circular.

Further questions and communication

Under section 319A of the Act, the Company must cause to be answered any question relating to the business being dealt with at the General Meeting put by a member attending the meeting unless answering the question would interfere unduly with the preparation for the meeting or involve the disclosure of confidential information, or the answer has already been given on a website in the form of an answer to a question, or it is undesirable in the interests of the Company or the good order of the meeting that the question be answered. Members who have any queries about the General Meeting should contact the Company Secretary by email at TullowCompanySecretary@tullowoil.com. Members may not use any electronic address or fax number provided in this Notice or in any related documents (including the Form of Proxy) to communicate with the Company for any purpose other than those expressly stated.

Documents available for inspection

The documents listed in Section 15 of Part VI (*Additional Information*) of the Circular will be available for inspection on the date of the General Meeting at the London offices of Tullow Oil plc at 9 Chiswick Park, 566 Chiswick High Road, London, W4 5XT from the date of this document up to and including the date of the General Meeting.