THIS DOCUMENT IS IMPORTANT AND REQUIRES YOUR IMMEDIATE ATTENTION.

If you are in any doubt as to the contents of this document, or about the action you should take, you are recommended to immediately consult your independent financial adviser (being, if you are resident in Ireland, an organisation or firm authorised or exempted pursuant to the Investment Intermediaries Act 1995 (as amended) or the European Communities (Markets in Financial Instruments) Regulations 2017 (as amended) or, if you are resident in the United Kingdom, an organisation or firm authorised or exempted pursuant to the Financial Services and Markets Act 2000 of the United Kingdom ("FSMA"), or another appropriately authorised adviser if you are in a territory outside Ireland or the United Kingdom).

If you sell or have sold or otherwise transferred all of your Existing Ordinary Shares, please send this Circular together with the accompanying documents as soon as possible to the purchaser or transferee, or to the stockbroker, bank or other agent through whom the sale or transfer was effected, for onward delivery to the purchaser or the transferee except that such documents should not be sent in, into or from any jurisdiction where to do so might constitute a violation of local securities laws or regulations. The distribution of this document and/or any accompanying documents in, into or from jurisdictions other than Ireland and the United Kingdom may be restricted by law and therefore persons into whose possession this document and/or any accompanying documents come should inform themselves about and observe any such restrictions.

For a discussion of certain risk factors which should be taken into account when considering whether to vote in favour of the Resolutions, see Part II of this document. This document should be read as a whole.

Aminex PLC

(Incorporated and registered in Ireland under the Companies Act 2014 with registered number 72399)

Proposed disposal of 50 per cent. interest in the Ruvuma Production Sharing Agreement in Tanzania

Notice of Extraordinary General Meeting

This Circular should be read as a whole. Your attention is drawn to the letter from the Chairman of the Company which is set out at Part I of this Circular and which recommends you to vote in favour of the Resolution to be proposed at the General Meeting referred to below. Please also see Part II of this Circular for a discussion of certain risk factors that you should consider carefully when deciding whether or not to vote in favour of the Resolution to be proposed at the General Meeting. The whole of this Circular should be read in light of these risk factors.

Notice of the Extraordinary General Meeting of Aminex PLC, to be held at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul's Churchyard, London, EC4M 8AL, United Kingdom, at 12.30 p.m. on 4 January 2019, is set out at the end of this document. A Form of Proxy for use at the Extraordinary General Meeting is enclosed and, whether or not you intend to attend the Extraordinary General Meeting in person, please complete, sign and return the Form of Proxy so as to be received by the Company's registrars, Computershare Investor Services (Ireland) Limited, at PO Box 954, Sandyford, Dublin 18, Ireland (if delivered by post) or at Heron House, Corrig Road, Sandyford Industrial Estate, Dublin 18, Ireland (if delivered by hand), by not later than 12.30 p.m. on 2 January 2019. Alternatively, you may appoint a proxy electronically, by visiting the website of the Company's Registrars at www.eproxyappointment.com. You will need the Control Number, your shareholder reference number and your PIN number, which can be found on your Form of Proxy. Completion and return of a Form of Proxy will not prevent Shareholders from attending and voting in person at the Extraordinary General Meeting or any adjournment thereof, should Shareholders wish to do so.

J&E Davy, which is regulated in Ireland by the Central Bank, is acting exclusively for Aminex PLC in connection with the contents of this Circular and the Transaction and for no-one else (including the recipients of this document) and will not be responsible to any other person for providing the protections afforded to customers of Davy or for providing advice in connection with the Transaction or any other arrangement referred to in this document. Apart from the responsibilities and liabilities, if any, which may be imposed on Davy by the Central Bank or by FSMA or the regulatory regime established thereunder, Davy does not accept any responsibility whatsoever and makes no representation or warranty, express or implied, for the contents of this document, including its accuracy, completeness or verification or for any other statement made or purported to be made by Davy, the Company or any other person, in connection with the Company or any other matter described in this document and nothing in this document shall be relied upon as a promise or a representation in this respect, whether as to the past or the future. Davy accordingly disclaims all and any liability whatsoever, whether arising in tort, contract or otherwise (save as referred to above), which it might otherwise have in respect of this document or any such statement.

No person has been authorised to give any information or make any representations other than those contained in this document and, if given or made, such representations must not be relied on as having been so authorised. The delivery of this document shall not, under any circumstances, create any implication that there has been no change to the affairs of the Company since the date of this document or that the information is correct as of any subsequent time.

This document does not constitute, or form part of, any offer or invitation to sell, or any solicitation of any offer to purchase or subscribe for any shares in the Company in any jurisdiction.

The contents of this document should not be construed as legal, business or tax advice. Each shareholder should consult his, her or its own legal adviser, financial adviser or tax adviser for legal, financial or tax advice.

This document is dated 7 December 2018.

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EXPECTED TIMETABLE OF PRINCIPAL EVENTS

Event	*Time and Date*
Date of issue of this document	7 December 2018
Latest time and date for receipt of Forms of Proxy and CREST Proxy Instructions for the Extraordinary General Meeting	12.30 p.m. on 2 January 2019
Time and date of Extraordinary General Meeting	12.30 p.m. on 4 January 2019
Expected Completion of the Transaction	by 31 March 2019

Notes

(i) References to times and dates in this document are to times and dates in Dublin, Ireland/London, UK.

(ii) The dates set out above and mentioned throughout this document may be adjusted by the Company, in which event details of new dates will be notified via a Regulatory Information Service and to the Euronext Dublin, the UK Listing Authority and the London Stock Exchange.

(iii) The Extraordinary General Meeting is being held at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul's Churchyard, London, EC4M 8AL, United Kingdom.

IMPORTANT INFORMATION

Completion of the Transaction is subject to conditions which are described in detail in Section 2 of Part III of this document.

All times referred to in this document are, unless otherwise stated, references to Dublin/London time.

Reference to Defined Terms and Incorporation of Terms

Certain terms used in this document, including capitalised terms and certain technical and other terms, are explained in Part VIII —"*Definitions*" and Part IX—"*Glossary*" of this document. References to the singular include the plural and *vice versa*.

Websites

The Company's website is www.aminex-plc.com. Without limitation, the information on this website or any website mentioned in this document or any website directly or indirectly linked to this website has not been verified and is not incorporated by reference into this document and investors should not rely on it.

Forward-looking statements and the risks associated with them

This document includes statements that are, or may be deemed to be, forward looking statements. These forward looking statements can be identified by the use of forward looking terminology, including the terms "anticipates", "believes", "estimates", "expects", "intends", "may", "plans", "projects", "should" or "will", or, in each case, their negative or other variations or comparable terminology, or by discussions of strategy, plans, objectives, goals, future events or intentions. These forward looking statements include all matters that are not historical facts. They appear in a number of places throughout this document and include, but are not limited to, statements regarding Aminex's and/or the Group's intentions, beliefs or current expectations concerning, amongst other things, Aminex's results of operations, financial position, prospects, growth, strategies and expectations for the industry in which it operates. By their nature, forward looking statements involve risk and uncertainty because they relate to future events and circumstances. Forward looking statements are not guarantees of future performance and the actual results of Aminex's operations, financial position, and the development of the markets and the industry in which Aminex operates may differ materially from those described in, or suggested by, the forward looking statements contained in this Circular. In addition, even if the results of operations, financial position, and the development of the markets and the industry in which Aminex and/or the Group operates, are consistent with the forward looking statements contained in this Circular, those results or developments may not be indicative of results or developments in subsequent periods. A number of factors could cause results and developments of Aminex and/or the Group to differ materially from those expressed or implied by the forward looking statements including, without limitation, general economic and business conditions, industry trends, competition, changes in regulation, currency fluctuations, changes in its business strategy, political and economic uncertainty.

Forward looking statements may, and often do, differ materially from actual results. Any forward looking statements in this document reflect Aminex's and/or the Group's current view with respect to future events and are subject to risks relating to future events and other risks, uncertainties and assumptions relating to Aminex's and/or the Group's operations, results of operations and growth strategy.

Save as required by the Prospectus Rules, the Listing Rules, the Market Abuse Regulations, the Transparency Regulations and Rules and the Disclosure Guidance and Transparency Rules, Aminex undertakes no obligation to update these forward looking statements and will not publicly release any revisions it may make to these forward looking statements that may occur due to any change in Aminex's and/or the Group's expectations or to reflect events or circumstances after the date of this document. Shareholders should note that the contents of these paragraphs relating to forward looking statements are not intended to qualify the statements made as to sufficiency of working capital in this document.

PART I

LETTER FROM THE CHAIRMAN

AMINEX PLC

(Incorporated and registered in Ireland under the Companies Act 2014
with registered number 72399)

Directors	*Registered Office*
Keith Phair *(Independent Non-Executive Chairman)*	6 Northbrook Road
Jay Bhattacherjee *(Chief Executive Officer)*	Dublin 6
Max Williams *(Chief Financial Officer)*	Ireland
John Bell *(Senior Independent Non-Executive Director)*	
Tom Mackay *(Independent Non-Executive Director)*	
Ola Fjeld *(Non-Executive Director)*	
Sultan Al-Ghaithi *(Non-Executive Director)*	

7 December 2018

Proposed disposal of 50 per cent. interest in the Ruvuma Production Sharing Agreement in Tanzania and Notice of Extraordinary General Meeting

Dear Shareholder,

1. INTRODUCTION

On 11 July 2018, the Board announced that the Company, and its wholly-owned subsidiary Ndovu, had entered into a conditional agreement with Zubair to farm-out a 50 per cent. interest in the Ruvuma PSA. The Group currently holds a 75 per cent. interest in the Ruvuma PSA which post Completion will consequently reduce to 25 per cent. interest. APT, an associate of Zubair, will become operator of the Ruvuma PSA with a view to accelerating development of the asset. In exchange for the 50 per cent. interest, APT will conduct a work programme comprising of, amongst other things, the drilling and testing of the Chikumbi-1 well and the establishment an early production system to achieve initial gas production from the Ntorya Field.

Pursuant to the Transaction, APT will carry Aminex for its share of development costs in respect of the Ntorya area up to US$35 million. Should the development of the Ntorya area not require APT to deploy capital on Aminex's behalf representing the full US$35 million, APT is required to make up the uninvested balance by paying cash to Ndovu from a proportion of APT's share of any future gas sales from the Ntorya Field. In addition, Aminex will receive a Cash Consideration at Completion of US$5 million, with US$3 million payable on Completion and US$2 million payable 180 days thereafter.

Further details of the terms of the Transaction are set out in Section 5 of this letter.

Your attention is drawn to Section 9 of this letter for more information on the importance of your vote.

The Transaction constitutes a related party transaction for the purposes of the Listing Rules, due to Zubair's associate company, Eclipse Investments LLC, having a 28.62 per cent. shareholding in the Company. In addition, due to the relative size, and the unlimited nature of an indemnity given by the Company in favour of Zubair under the terms of the Farm-Out Agreement, the Transaction is a Class 1 transaction for the Company under the Listing Rules. Under the Listing Rules, both a related party transaction and a Class 1 transaction require the approval of Shareholders and accordingly the Transaction is conditional on the approval of the Shareholders. An extraordinary general meeting of the Company is being convened for 12.30 p.m. on 4 January 2019 at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul's Churchyard, London, EC4M 8AL, United Kingdom for the purpose of considering, and if thought fit, approving the Transaction. The notice convening the Extraordinary General Meeting is set out at the end of this document. The Transaction is also conditional, *inter alia*, upon certain approvals of the Government of Tanzania.

The purpose of this document is to provide you with details of, and background to, the Transaction, to explain why your Board considers it to be in the best interests of Shareholders as a whole and to recommend that you vote in favour of the Resolution set out in the notice of Extraordinary General Meeting at the end of this document.

2. BACKGROUND TO, AND REASONS FOR, THE TRANSACTION

Aminex's intention is to create shareholder value by developing its portfolio of assets in Tanzania and to seek opportunities in new areas within and outside Africa to balance cost and risk. Aminex's strategy has been to identify prospects on its licences within Tanzania which could be brought onto production close to existing infrastructure. One of the key components of the Group's strategy is to actively manage the Group's portfolio and over several years Aminex has sought partners to share production and development risks over its assets as they mature.

In August 2016, Aminex completed a capital raising of approximately Stg£19.5m which included a strategic equity investment by The Zubair Corporation of Stg£12.8 million. The Zubair Corporation, through its associate company Eclipse, became the Company's largest shareholder with a holding representing, at the time, 29.9 per cent of the then issued share capital and received the right to appoint two non-executive directors to the board of the Company. The Board's rationale for the strategic capital raise was to introduce a strong, supportive shareholder that would greatly assist development of the Company's Tanzanian assets and the strategic investment, together with the balance of the capital raise, facilitating the Company in advancing its capital expenditure programme in Tanzania and specifically the drilling of the Ntorya-2 well. Eclipse subsequently appointed two Directors, Mr. Sultan Al-Ghaithi and Mr. Ola Fjeld, who brought additional strong industry experience to the Board.

In line with its general corporate strategy, Aminex has sought to enhance the value of the Ruvuma PSA through exploration and appraisal work, and subsequently secure a strong partner that would share the development risk at the appropriate time. The Board's long-held belief was that the Company would ultimately benefit from a farm-out of part of its interest in the Ruvuma PSA to enable the development by a larger, well-capitalised partner that could better manage timing and execution of a substantial development programme without the constraints of capital which have delayed Aminex's progress from time to time.

Moreover, the Group has historically been dependent on external funding for the continuation of the exploration, appraisal and development of its assets. While the Group has historically been successful in raising equity funding for its exploration and appraisal programme, the Board concluded that a farm-out would provide the Group with the financial flexibility to create greater shareholder value from the Ruvuma assets without the necessity for short- to medium-term share issuance dilution and accelerate the generation of revenues and cash flows from the Ntorya Field.

Following the success of the Ntorya-2 well, drilled and tested in 2017, the Company carried out analytical work and revised the basin model for Ruvuma which resulted in a substantial increase in independent resource estimates to 1.87 TCF Pmean GIIP and 763 BCF of 2C Contingent Resources for the Ruvuma PSA. This successful appraisal work lead to the Company announcing on 21 March 2018 that the Company was in discussions with Eclipse regarding a possible farm-out and the subsequent announcement on 11 July 2018 of the proposed farm-out to Zubair of a 50 per cent. interest in the Ruvuma PSA.

The carry of up to US$35 million pursuant to the Transaction will allow the acceleration of the development of and production from the Ntorya Field. Moreover, the Board believes that the Group will be able to access cash, including surplus cash flow from future revenues generated by its remaining 25 per cent. interest in the Ruvuma PSA and specifically the Ntorya Field, to continue development of its remaining discovered resource base and will continue to explore and develop the Group's significant existing prospective resource potential. In addition, the Board believes the Group will be able to fund any long term future development costs for the Ntorya Field beyond the proposed carry amount of US$35 million from its share of future cash flows generated from the field should the need arise.

3. INFORMATION ON THE RUVUMA PSA

Ndovu (incorporated in Tanzania), a wholly-owned subsidiary of Aminex, signed the Ruvuma PSA in October 2005, originally comprising two separate and adjacent licences known as Lindi and Mtwara. The Ruvuma Area is located immediately to the north of the Mozambique border and is predominantly onshore. Currently Ndovu holds a 75 per cent. participating interest in the Ruvuma PSA with the remaining 25 per cent. held by Solo Oil.

Two exploration wells (Likonde-1 drilled in 2010 and Ntorya-1 drilled in 2012) and one appraisal well (Ntorya-2 drilled in 2017) have been drilled in the Ruvuma Area. The Likonde-1 exploration well encountered gas shows. Both the Ntorya-1 exploration well and the Ntorya- 2 appraisal well successfully tested gas with flow rates of 20 mmscf/d and 17 mmscf/d respectively. Subsequent technical work concluded that there are 763 BCF of 2C Contingent Resources associated with the Ruvuma PSA, as evaluated in an independent resource report, summarised in the Resources section below. Sparse multi-vintage (2005, 2007, 2014) 2D seismic covers the Ruvuma Area with line length totalling 2,955km.

Both the Lindi and Mtwara Licences have expired. Ndovu has applied for an extension to the Mtwara Licence and the Board has been given a reasonable assurance from the Ministry of Energy for Tanzania of a favourable outcome before completion of the Transaction. The Company expects the extension to be for 1 year with an option to extend the term by a further 2 years. The Company expects that an application for a new production sharing agreement in respect of the area previously governed by the Lindi Licence will be made by the TPDC and Ndovu would seek to become the contractor for the new licence but a firm indication cannot given as to when the application will be sought. The Lindi Licence area is not included in the Farm-Out Agreement.

In September 2017, Ndovu applied to the Ministry of Energy for Tanzania for a 25-year development licence over the Ntorya Blocks. While the Board has a reasonable expectation of Aminex securing the development licence, the Board cannot give a firm indication as to when the approval will be granted. Approval of the Ntorya Development Licence is neither a pre-condition for the Farm-Out Agreement nor is it necessary for the drilling of the Chikumbi-1 well. The initial development work programme in respect of the development licence application recommended the drilling of one well, acquiring 3D seismic over the Ntorya Field and the construction of a raw gas pipeline to the National Gas Gathering System at the Madimba Gas Processing Plant, designed to accelerate first gas production.

Ndovu is actively engaged with the Tanzanian authorities and with third-party engineering firms on advanced well planning and drilling management for the Chikumbi-1 well, which is planned to be drilled as soon as operationally possible after receiving the grant of extension to the Mtwara Licence. Chikumbi-1 is being designed to test the deeper Jurassic sandstones, thereby fulfilling one of the exploration commitment wells on the Mtwara Licence, and to delineate the Ntorya Field, with the well expected to be completed as a producer. Pursuant to the work commitments terms of the Farm-Out Agreement, APT will undertake the drilling of the Chikumbi-1 well and will acquire approximately 200 km^2 of 3D seismic over the proposed Ntorya development area. Aminex's portion of the costs relating to these works will be fully carried by APT (see Section 5 of this Part I for more information).

Resources

There are currently no hydrocarbons categorised as reserves in the Ruvuma Area.

Resources are defined as contingent resources and prospective resources. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent resources have an associated chance of development. Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development.

The Ntorya-1 well drilled in early 2012 intersected a 27-metre gross sand interval of Mid-Cretaceous age. The upper 3.5 metres were perforated and tested in June 2012 and gas flowed at rate of 20 mmscf/d with an estimated 139 barrels of 53 degrees API associated condensate through a one-inch choke. In early 2017, the Ntorya-2 appraisal well was drilled and encountered 31 metres of net pay and 51 metres of gross reservoir. Ntorya-2 was tested and produced at a stabilised rate of approximately 17 mmscf/d through a 40/64" choke.

Set out below are the contingent and prospective resources for the Ruvuma PSA as at 4 December 2018. The volumes for gas have been extracted without material adjustment from the Technical Report prepared by RPS Energy and are presented in accordance with the PRMS. The Technical Report is set out in full in Part VII of this Circular.

Licence Status	Contingent Resources (Bscf)[1]									
	Gross (100%) Licence Basis			Ndovu's Net Working Interest Basis[2]			Ndovu's Net Entitlement Basis[3]			Pd (per cent.)[4]
	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Ntorya Development Pending	26	81	213	19	60	160	16	52	123	75
Ntorya Development Unclarified	342	682	945	257	512	712	195	354	466	25

1. Assuming Ntorya Development Licence is ratified.
2. Aminex working interest is 75%.
3. Net entitlement is based on Aminex share of Cost Gas and Profit Gas calculated using the assumed PSA terms.
4. Pd is Chance of Development.

Lead	GIIP (Bscf)[3]			Prospective Resources (Bscf)[3]						
	Gross on Licence			Gross on Licence			75% Working Interest			Pg (per cent.)[4]
	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
Ntorya[1, 2]	589	1,351	2,522	399	936	1,798	299	702	1,350	8
Namisange	81	467	2,762	56	325	1,925	42	244	1,444	8
Likonde Updip	57	239	1,006	39	166	702	29	125	527	10
Ziwani NW	n/a	n/a	n/a	8	35	153	6	26	115	<5
Ziwani SW	n/a	n/a	n/a	12	54	236	9	41	177	<5

1. Assuming Ntorya Development Licence is ratified.
2. GIIP and prospective resources in Chikumbi-1 Prospect (in the Jurassic below Ntorya development).
3. Assumes PSA term is extended.
4. Pg is Chance of Geological Discovery.

4. FINANCIAL EFFECTS OF THE TRANSACTION AND USE OF PROCEEDS

The aggregate cash consideration for the Transaction is US$5 million, with US$3 million payable on Completion of the Transaction and US$2 million payable 180 days thereafter. The Company's current intention is to use the Cash Consideration to progress planning for acquisition of 3D seismic over parts of the Kiliwani North Development Licence and the Nyuni Area PSA at an estimated cost of US$1.2 million. The balance of cash available will be used to augment working capital and to assist with the identification of other oil and gas assets.

The overall effect of the Transaction is not expected to give rise to a material change in the consolidated net assets for the Group in the next full financial year as the Group's costs in respect of development programme for the Ruvuma PSA will be carried pursuant to the Transaction. Moreover, the Transaction is not expected to impact the earnings of the Group in the next full financial year.

A pro forma statement of net assets for the Group is provided in Part V of this document and has been prepared to illustrate the effect of the Transaction on the net assets of the Group as if the Transaction had taken place on 30 June 2018. The unaudited pro forma statement of net assets has been prepared for illustrative purposes only and, because of its nature, addresses a hypothetical situation and, therefore, does not reflect the Group's actual financial position or results.

The Transaction may give rise to certain potential tax liabilities. However, through the application for exemptions and taking into account accumulated tax losses, the Group believes that any tax liabilities payable will not be material relative to the cash proceeds of the Transaction. The amount of this liability will be determined following discussions with the relevant authorities in Tanzania and it is not yet possible to confirm the amount of such liability.

5. PRINCIPAL TERMS OF THE TRANSACTION

The Transaction will be effected in accordance with the terms of the Farm-Out Agreement and is conditional upon, among others things, the approval of Shareholders. In exchange for a 50 per cent. interest in the Ruvuma PSA, APT will become operator and will conduct the following minimum work programme:

- Drill, complete, and test Chikumbi-1 (formally Ntorya-3) as soon as reasonably practicable;
- Acquire, process and interpret 3D seismic over a minimum of 200 km2 within the Ntorya area, which Aminex believes to be the first time 3D seismic has been acquired onshore Tanzania; and
- Establish an early production system to achieve accelerated first gas to a minimum gross rate of 40 mmcfd (equivalent to approximately 6,700 bbls/d).

The aggregate Cash Consideration to be received by the Group at Completion of the Transaction is $5 million, with US$3 million payable on Completion and US$2 million payable 180 days thereafter.

APT will fully carry Aminex for its share of costs up to US$35 million in respect of its remaining 25 per cent. interest in the Ruvuma PSA, which implies a potential expenditure during the carry period of up to US$105 million for the aggregate 75 per cent. working interest held by APT and Aminex. In the event that the minimum production target of 40 mmcfd is achieved prior to Aminex's 25 per cent. interest having been carried for the full US$35 million, APT will assign one quarter of its share of profit gas to pay the unspent carry amount until the full US$35 million is realised by Aminex. The Board expects that gas production from the Ntorya Field will be significantly more than 40 MMcf/d.

The Farm-Out Agreement contains certain warranties and indemnities from Aminex in favour of Zubair. In particular, Aminex has agreed to indemnify Zubair in respect of any claim by the Tanzanian Government or the TPDC relating to pre-Effective Date work commitments in respect of the Ruvuma PSA which the Tanzanian Government or the TPDC consider have not been completed. This indemnity is unlimited as to time and amount.

A summary of the Farm-Out Agreement is set out in Part III of this Circular.

6. INFORMATION ON ZUBAIR AND RELATED PARTIES

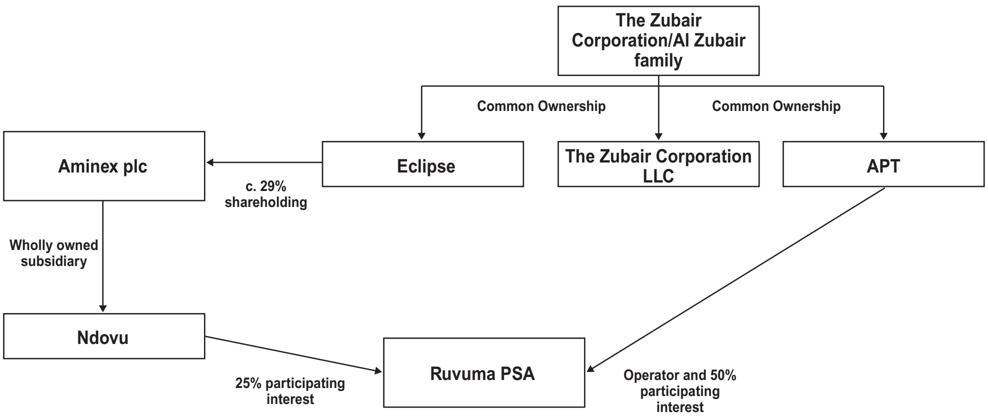
The Zubair Corporation is a family owned business conglomerate which is headquartered in Muscat, Oman. Since its formation by Mohammad Al Zubair in 1967, the company has evolved into a large conglomerate operating over six business verticals, energy and logistics, automotive, engineering, construction and contracting, real estate and hospitality, financial services and information and communication technology and manufacturing. Today, Mohammad Al Zubair and his seven children are the shareholders of The Zubair Corporation. APT, which will assume operatorship of the Ruvuma PSA post completion of the Transaction, and Zubair are associates under the Listing Rules as they are under the common ownership of The Zubair Corporation.

Eclipse is the Company's largest shareholder with an interest of 28.62 per cent. in the Ordinary Shares of the Company and therefore a related party of the Company under the Listing Rules. Eclipse is wholly-owned by members of the Al Zubair family, who in turn own 100 per cent of Zubair. Consequently, Zubair is an associate of Eclipse and therefore a related party of the Company under the Listing Rules. Accordingly, the Transaction is classified as a related party transaction under the Listing Rules and is subject to, and conditional upon, *inter alia* the approval of the Shareholders at the Extraordinary General Meeting.

Eclipse and Zubair will not be entitled to vote on the Resolution and have undertaken to take all reasonable steps to ensure that their associates will not vote at the Extraordinary General Meeting in relation to the approval of the Transaction and at any adjourned meeting.

Mr. Ola Fjeld and Mr. Sultan Al-Ghaithi, two Directors appointed by Eclipse pursuant to the Relationship Agreement, have not taken part in the Board's consideration of the Transaction and have undertaken to take all reasonable steps to ensure that their associates will not vote at the Extraordinary General Meeting in relation to the approval of the Transaction and at any adjourned meeting.

The diagram below sets out the relationship between Aminex and Zubair post Completion.



7. INFORMATION ON THE GROUP

Post Completion, the Group's principal area of focus will continue to be on creating shareholder value by further development and exploration of its portfolio of assets in Tanzania. In addition, the Group will continue to hold a royalty interest in Egypt and continues to look at new venture opportunities that will provide low risk, robust returns to shareholders whilst diversifying the asset base and risk profile of the Company.

The table below sets out the material exploration, appraisal, development and production assets of the Group post Completion.

Country	*Asset*	*Interest (%)*	*Gross area*	*Operator*	*Type*
Tanzania	Nyuni Area PSA(1)	100	845 km^2	Aminex	Exploration
	Ruvuma PSA	25(2)	1,682 km^2	APT	Exploration
	Kiliwani North Development Licence	63.8304	84 km^2	Aminex	Production

Notes:

(1) Following payment default by Bounty Oil & Gas NL, Aminex interests for Nyuni Area PSA and the Kiliwani North Development Licence have increased from 93.3333 per cent and 57.4474 per cent respectively. The amendment to partners' interests remain subject to the completion of certain formalities.

(2) The Company's participating interest in the Ruvuma PSA reduces from 75 per cent to 25 per cent post Completion.

Tanzania

Aminex made its initial investment in Tanzania in 2002 and is currently party to two production sharing agreements (the Nyuni Area PSA and the Ruvuma PSA), the Kiliwani North Development Licence and has applied for a development licence over the Ntorya Field. The Company has operated in Tanzania for 16 years, as well as globally for over 25 years, and has demonstrated an ability to find, appraise and develop oil and gas fields successfully from first concept through to production. In addition, the Directors affirm that the Group has extensive and constructive relationships with local stakeholders including the Tanzanian authorities and the country's national oil company.

Since 2002, Aminex has participated in the drilling of seven wells in Tanzania, including six as operator, and has made two gas discoveries and successfully drilled an appraisal well in 2017.

Ruvuma PSA

Post Completion of the Transaction, Aminex will retain a 25 per cent. interest in the Ruvuma PSA. Details on the proposed work programme for the Ruvuma PSA are set out under Section 5 of this Part I above.

Kiliwani North Development Licence

The Kiliwani North Development Licence was granted in April 2011 and includes the Kiliwani North-1 gas well, which commenced production in April 2016. The Licence is governed by the terms of the Nyuni East Songo Songo PSA, although the exploration phase of this licence ended in 2011.

The Gas Sales Agreement for Kiliwani North is dated 31 December 2015. Key aspects of the Gas Sales Agreement include: take or pay provisions (meaning the TPDC purchase as much gas as can be delivered by the Kiliwani North-1 well), payment protection, transaction and payment currency in US dollars. The initial price of gas under the agreement was set at US$3.00 per mmBTU and is indexed to the US urban CPI. In the second half of 2017, production rates and well pressure started to decline. In 2018, production has continued to fail to meet expectations and as at the Latest Practicable Date, the Company was not producing gas from the well. Kiliwani North-1 had been the Company's only producing asset. The Company is currently implementing a well remediation programme with the intent of increasing production over the existing reservoir sands and also potentially perforate an untested deeper zone. Consideration has been given to the installation of a compressor and this remains an option whether or not the Company proceeds with the perforation of the lower zone.

RPS Energy (February 2018 Competent Person's Report) ascribed 2P reserves to the Kiliwani North-1 well of gross 1.94 billion cubic feet and mean GIIP for the Kiliwani North structure of gross 30.8 billion cubic feet.

Nyuni Area PSA

The Nyuni Area PSA was awarded in late 2011 for an eleven-year period and replaced the Nyuni East Songo-Songo PSA after it had expired, with all obligations met and a commercial discovery established. Aminex has drilled, as operator, four exploration wells in the Nyuni acreage since 2003, including the Kiliwani North gas discovery which is now the subject of a separate development licence.

Egypt

Aminex retains a 1 per cent. gross overriding royalty on all sales revenues in excess of US$2.5 million from the South Malak-2 discovery well. This well is not yet on production.

8. CURRENT TRADING AND PROSPECTS OF THE GROUP

On completion of the Transaction, Aminex intends to progress its Tanzanian assets and other opportunities. The Company's technical team has experience of operating in many hydrocarbon regions worldwide and consideration is being given to opportunities which would provide a balance of cost and risk with its existing assets in Tanzania.

Ruvuma PSA

The Company's remaining 25 per cent. interest in the Ruvuma PSA is expected to require no further material investment by Aminex in the medium term as the Transaction provides the potential to accelerate the development of the Ntorya Field through to material levels of production without recourse for further equity or asset dilution by the Company.

Kiliwani North Development Licence

In April 2018 Aminex received a letter from the TPDC requesting payment of certain amounts of which Aminex's share is US$2.73 million (net) for liabilities arising on revenues from gas sales from Kiliwani North-1. Aminex refutes TPDC's position and remains in discussions with the TPDC. No provisions have been made in the financial statements beyond amounts Aminex had already accrued. Pending the outcome of these discussions, the TPDC has withheld payments due and invoiced for Kiliwani North gas sales and interest thereon amounting to US$2.99 million (net) and this has impacted short-term cash flow.

Nyuni Area PSA

Aminex intends to develop further the potential for additional gas production and revenues from its Kiliwani North Development and the Nyuni Area Licences to utilise existing capacity at the Songo Songo Island Gas Processing Plant. The Company is therefore planning to acquire 3D seismic data over leads on both the Kiliwani North Development Licence and the Nyuni Area Licence. The programme is intended to cover leads which will be further assisted by the reprocessing of existing 2D seismic and will cover the Kiliwani North and Kiliwani South structures and leads identified over and around Nyuni Island where Aminex has previously drilled the Nyuni-1/1A and Nyuni-2 wells. In order to take advantage of economies of scale, Aminex would seek to acquire all of the 3D seismic data as part of one programme. Prior to acquiring the 3D seismic data, Aminex has requested that the work commitment for the Nyuni Area PSA be amended so that the current work commitment to acquire 3D seismic data over the deep-water is transferred to the shallow-water and shelf and with an overall alteration to the size of the surveys. Approval of the amendment to the work commitment for the Nyuni Area PSA is pending the approval of the Tanzanian authorities and while the Board has a reasonable expectation of Aminex receiving the approval, the Board cannot give a firm indication as to when the approval will be granted. Preparations for the acquisition of 3D seismic data will be financed by the proceeds of the Transaction and, if Completion does not occur, the preparation work will not be undertaken in the short term, that is for at least the next 12 months from the date of this Circular unless alternative financing is secured. Presently the Company does not intend acquiring the 3D seismic in the short term, being the 12-month period from the date of this Circular. The ultimate timing for the acquisition is dependent on Aminex securing equity or alternative financing the timing of which is uncertain.

9. IMPORTANCE OF VOTE

The Company is of the opinion that, taking into account existing cash resources and the net proceeds of the Transaction, the Group has sufficient working capital for its present requirements, that, is for at least the 12-month period from the date of this Circular.

If the Resolution is not approved at the EGM, the Transaction would not complete and the Company would not receive the net proceeds from the Transaction. As explained in Section 4 above, it is the Board's intention to use the net cash proceeds from the Transaction to progress planning for acquisition of 3D seismic over parts of the Kiliwani North Development Licence and the Nyuni Area PSA, to augment working capital and to assist with the identification of other oil and gas assets. If the Transaction does not proceed, the Group would have to curtail its preparation for the acquisition of 3D seismic, have less working capital headroom and significantly curtail the search for assets.

As noted in Section 7 above, the Company is not currently producing gas from the Kiliwani North-1 well and the Board cannot determine with a reasonable level of certainty as to when production will re-commence. Kiliwani North was the Company's only producing asset and primary source of revenue. Consequently, in the preparation of this Circular, the Board has assumed that payments from TPDC for invoiced gas sales from Kiliwani North will be the Company's only source of cash flow from operations over the 12-month period from the date of this Circular.

The Board expects TPDC will recommence making payments for invoiced gas sales within the requisite time period. However in the event of no payments being made, the Group having not received the net proceeds of the Transaction, and no mitigating actions being taken by Aminex, it is possible that the Group would have a working capital shortfall in the 12 month period from the date of this Circular. In these circumstances, the Group has a range of mitigating actions available to deal with a potential cash shortfall. Such actions could include reducing the Group's cost base including technical and administrative overheads, reducing capital expenditure and conserving cash through stricter working capital management. In the event that TPDC does not make any payments in respect of invoiced gas sales and the Group has not received the proceeds of the Transaction, these mitigating actions may need to provide additional working capital of up to approximately US$2.86 million in aggregate over the period from April 2019 to 31 December 2019 which primarily relates to the Company's general and administrative expenses.

Whilst the Directors are confident that such mitigating actions could be achieved within the requisite time period, the consequences of such actions would be inconsistent with the long-term strategy of the Group and in particular would mean that the medium term strategy would be substantially, or entirely, curtailed. As an alternative, the Group could seek to undertake a non-pre-emptive equity issue or seeking a loan or credit facilities in order to provide short term financing arrangements however there can be no guarantee that such financing would be available within the requisite time period.

10. EXTRAORDINARY GENERAL MEETING

A notice convening the Extraordinary General Meeting, to be held at 12.30 p.m. on 4 January 2019 at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul's Churchyard, London, EC4M 8AL, United Kingdom is set out at the end of this document. The purpose of the Extraordinary General Meeting is to seek Shareholder approval of the Resolution in connection with the Transaction.

The Resolution is an ordinary resolution to approve the Transaction on the terms and subject to the conditions of the Farm-Out Agreement.

The full text of the Resolution is set out in the notice convening the Extraordinary General Meeting at the end of this document.

11. ACTION TO BE TAKEN

You will find enclosed with this document the Form of Proxy for use at the Extraordinary General Meeting or at any adjournment thereof. You are requested to complete and sign the Form of Proxy in accordance with the instructions printed on it and return it as soon as possible to, but in any event so as to be received no later than 12.30 p.m. on 2 January 2019, by Computershare. You may also deliver the Form of Proxy by hand to Computershare during usual business hours. CREST members may also choose to use the CREST electronic proxy appointment service in accordance with the procedures set out in the notice convening the Extraordinary General Meeting at the end of this document.

12. FURTHER INFORMATION AND RISK FACTORS

Your attention is drawn to the further information set out in Parts II to VII (inclusive) of this document and, in particular, to the Risk Factors at Part II of this document.

13. RECOMMENDATIONS AND VOTING INTENTIONS

The Board, which has been so advised by Davy, acting as sponsor (for the purposes of the Listing Rules) to the Company, considers the terms of the Transaction, including the Indemnity, to be fair and reasonable as far as Shareholders are concerned. In providing financial advice to the Board, Davy has taken into account the Directors' commercial assessments of the Transaction.

In addition, the Board considers the terms of the Transaction, including the Indemnity, to be in the best interests of Shareholders as a whole. Accordingly, the Board unanimously recommends that Shareholders vote in favour of the Resolution, as each of the Directors intend to do in respect of their own beneficial shareholdings, amounting to 60,939,811 Ordinary Shares in aggregate, representing approximately 2.34 per cent. of the existing Voting Share Capital as at the Latest Practicable Date.

Mr. Ola Fjeld and Mr. Sultan Al-Ghaithi, two Directors appointed by Eclipse pursuant to the Relationship Agreement, have not taken part in the Board's consideration of the terms of the Transaction, including the Indemnity, and have undertaken to take all reasonable steps to ensure that their associates will not vote at the Extraordinary General Meeting in relation to the approval of the Resolution and at any adjourned meeting.

Yours sincerely,

Keith Phair
Chairman

PART II

RISK FACTORS

Prior to making any decision to vote in favour of the proposed Resolution at the Extraordinary General Meeting, Shareholders should carefully consider, together with all other information contained in this document, the specific risk factors described below. The Directors consider the following to be all the material risks of which the Directors are currently aware. There may be other risks of which the Board is not aware or which it believes to be immaterial which may have an adverse effect on the business, financial condition, results or future prospects of the Group after the Transaction. The majority of the risk factors set out below are contingencies which may or may not occur and the Board is not in a position to express a view on the likelihood of any such contingency occurring.

1. Risks relating to the Transaction not proceeding

The Group may not realise the perceived benefits of the Transaction if it does not complete

The Board believes that the Transaction is in the best interests of Shareholders as a whole and that it currently provides the best opportunity to realise cash value and an attractive carried interest in the Ruvuma PSA. If the Transaction does not proceed, the Group will not receive the net cash proceeds due pursuant to the terms of the Farm-Out Agreement and its ability to implement the Group's stated strategy of creating shareholder value by further development and exploration of its portfolio of assets in Tanzania may be prejudiced. In addition, the Group may have difficulty realising a farm-out of the Company's interest in the Ruvuma PSA in the near future on the same or better terms as those offered pursuant to the Transaction.

If the Transaction does not complete, the planned work on the Ntorya Field per the terms of the Farm-out Agreement will not be undertaken by the Group, and specifically the drilling of the Chikumbi-1 well, in the short term being the 12 month period from the date of this Circular. The timing for drilling of the Chikumbi-1 well would be uncertain as it would be dependent on Aminex's ability to secure an alternative partner or attaining equity financing. Delaying this work would not be in the interests of the Company as it would delay production and revenues from the Ntorya Field.

The Transaction is conditional upon, amongst other things, the approval of Shareholders at the EGM and relevant approvals of the Transaction being granted by the Ministry of Energy for Tanzania. There can be no assurance that these, and the other Conditions will be satisfied and that Completion will be achieved by the long stop date of 31 March 2019 or at all. Although the Board is confident that the requisite approvals will be obtained, there can be no assurances as to the timing or outcome of this process.

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

If the Resolution is not approved at the EGM, the Transaction would not complete and the Company would not receive the net proceeds from the Transaction. It is the Board's intention to use the net cash proceeds from the Transaction to progress planning for acquisition of 3D seismic over parts of the Kiliwani North Development Licence and the Nyuni Area PSA, to augment working capital and to assist with the identification of other oil and gas assets. If the Transaction does not proceed, the Group would have to curtail its preparation for the acquisition of 3D seismic, have less working capital headroom and significant curtail the search for assets.

The Company is not currently producing gas from the Kiliwani North-1 well and the Board cannot determine with a reasonable level of certainty as to when production will re-commence. Kiliwani North was the Company's only producing asset and primary source of revenue. Consequently, in the preparation of this Circular, the Board has assumed that payments from TPDC for invoiced gas sales from Kiliwani North will be the Company's only source of cash flow from operations over the 12-month period from the date of this Circular.

The Board expects TPDC will recommence making payments for invoiced gas sales within the requisite time period. However in the event of, no payments being made, the Group having not received the proceeds of the Transaction, and no mitigating actions being taken by Aminex, it is possible that the Group would have a working capital shortfall in the 12 month period from the date of this Circular. In these circumstances, the Group has a range of mitigating actions available to deal with a potential cash shortfall. Such actions could include reducing the Group's cost base including technical and administrative overheads, reducing capital expenditure, and conserving cash through stricter working capital management. In the event that TPDC does not make any payments in respect of invoiced gas sales and the Group has not received the proceeds of the Transaction, these mitigating actions may need to provide additional working capital of up to approximately US$2.86 million in aggregate over the period from April 2019 to 31 December 2019 which primarily relates to the Company's general and administrative expenses.

Whilst the Directors are confident that such mitigating actions could be achieved within the requisite time period, the consequences of such actions would be inconsistent with the long-term strategy of the Group and in particular would mean that the medium term strategy would be substantially, or entirely, curtailed. As an alternative, the Group could also seek to undertake a non-pre-emptive equity issue or seeking a loan or credit facilities in order to provide short term financing arrangements.

2. Risks relating to the Transaction

The Group will no longer have a right of veto by itself over significant matters relating to the operation of the Ruvuma PSA

The Group currently has a 75 per cent. Participating Interest in and maintains operatorship of the Ruvuma PSA. Post Completion of the Transaction, the Group will have a 25 per cent. Participating Interest and APT will have a 50 per cent. Participating Interest and assume operatorship. Although the Group will have consultation rights or the right to withhold consent in relation to significant operational matters, it has limited control over day-to-day management. There is a risk that the Group and APT may disagree in relation to the operations and activities carried out by APT as operator (including decisions relating to drilling programmes, including the number, identity and sequencing of wells, appraisal and development decisions and decisions relating to production and including in respect of certain material decisions, as outlined above). In these circumstances, and in particular where the Group no longer has a right of veto in respect of such decisions, such activities may be undertaken irrespective of the intentions of the Group at a time or in a sequence which the Group considers is not in the best interests of the Group and which may adversely affect the Group's business, prospects, financial condition and results of operations.

Warranties and indemnities in the Farm-Out Agreement

The Farm-Out Agreement contains certain warranties and indemnities from Aminex in favour of Zubair. In particular, Aminex has agreed to indemnify Zubair in respect of any claim by the Tanzanian Government or the TPDC relating to pre-Effective Date work commitments in respect of the Ruvuma PSA which the Tanzanian Government or the TPDC consider have not been completed. This indemnity is unlimited as to time and amount. If the Group is required in the future to make payments under any of the warranties or indemnities the costs of such payments could have an adverse effect on its business, financial condition and results of operations. Further details of the Farm-Out Agreement, including the indemnities, are set out in Part III (Principal Terms of the Farm-Out Agreement) of this Circular.

The Group does not receive a development licence over the Ntorya Field

Although not a condition to the Completion of the Transaction, in order for the Group to take advantage of the terms of the Farm-Out Agreement, and in particular the carry under the Farm-Out Agreement, the Group and its partners in the Ruvuma PSA, will require the grant of a development licence over the Ntorya Field. Although the Directors of Aminex believe that a development licence will be granted, Aminex may experience difficulties or delays with respect to the grant of the development licence. Should such a delay arise, it may have a material adverse effect on the Group's business, prospects, financial condition and results of operations.

3. Risks relating to the Group

Position regarding outstanding debts owed by the TPDC

Included in trade and other receivables at 30 June 2018 is an amount of US$7.22 million due from the TPDC for the gross receivables due to the partners in jointly controlled operations for gas sales from Kiliwani North. Aminex's net share of the receivable is US$2.99 million. On 11 April 2018, the Company received notification from the TPDC of certain claims amounting to US$5.97 million for liabilities arising on revenues from gas sales, of which Aminex's share is estimated to be US$2.73 million. Aminex has advised the TPDC that it does not accept the claims and no provision has been made in the financial statements beyond amounts Aminex had already accrued. No amounts have been received from the TPDC while the Company and the TPDC continue discussions. However, as the trade receivable balance is not disputed Aminex anticipates recovering the full amount.

If Aminex is unable to resolve, in whole or in part, the claims made by the TPDC which are delaying the receipt of payments for outstanding gas invoices, the Company may be unable to carry out further work on the Kiliwani North Development Licence and the Nyuni Area PSA which may impact on the timing of additional future revenues. See the risk factor entitled "*The Company may face risks associated with its funding position if the Transaction does not complete*" for further risks relating to outstanding debts owed by the TPDC.

The Group's business requires significant capital expenditure and the future expansion and development of the Group's business could require future debt and equity financing. The future availability of such funding is not certain

The Group's business requires significant capital expenditure and future expansion and development of its business and capital expenditure beyond the Group's current committed capital expenditure for the next 12 months could require debt or further equity financing. The availability of any future funding, whether obtained through debt or equity financing, is not certain. Alternatively, the Group may in the future seek funds for such activities by selling part of its operations and/or by farming down its assets. If the Group is unable to generate or obtain further additional funding (for expenditure beyond its current committed capital expenditure for the next 12 months) it is likely to be limited in its ability to undertake any additional operations, exploration, appraisal, development or appraisal plans. If the Transaction completes, the Group's contribution towards any capital expenditure required in respect of the Ruvuma PSA will be significantly reduced.

Exploration activities are capital intensive and their successful outcome cannot be assured

The success of Aminex primarily depends on its ability to acquire, find, develop and commercially exploit resources and reserves within its Tanzanian assets. Exploration and development activities are capital intensive and their successful outcome cannot be assured. Aminex undertakes exploration activities with no guarantee that such expenditure will result in the discovery of commercially recoverable oil or gas.

If Aminex should make no discoveries from which it is able to produce oil or gas commercially, or if appraisal and development of discoveries should prove unsuccessful, then this would have a material and adverse impact on the business, prospects, financial condition and results of operations of Aminex.

There is a long lead time between discovery and production of oil and gas, particularly for gas. During this long lead time, Aminex will incur significant costs at a level which may be difficult to predict. It will also have exposure to many of the risk factors described in this Part II, and may become exposed to additional risks not currently envisaged. These risks may individually or collectively diminish the returns obtainable by Aminex in relation to any discovery or even the ability to realise any value from the discovery at all, which may have a material adverse effect on the business, prospects, financial position and results of operations of Aminex.

The Group may be unable to acquire, retain, convert or renew the licences, permits and contracts and other regulatory approvals necessary for its operations

The ability of the Group to develop and exploit oil and gas reserves depends on the Group's continued compliance with the obligations of its current exploration and development licences and the Group's ability to convert these licences into production licences. The continuing validity of the licences and their renewal depends on the steps taken by the Group or its joint activity partners to maintain their good standing. The Group depends on a number of approvals, permits, licences and contracts whose grant and renewal are subject to the discretion of, *inter alia*, government or petroleum industry regulatory authorities in those countries in which the Group operates and cannot be assured. As a result, the Group may have limited control over the nature and timing of development and exploration of oil and gas fields in which it has or seeks interests and therefore the continued good standing and, where appropriate, renewal of these approvals, permits and licences cannot be assured. In addition, exploration licences held by the Group may not be converted into development licences. Any withdrawal, non-renewal or change in the terms of any of the above could materially adversely affect the Group's business, prospects, financial condition and results of operations.

Moreover, if the Group does not meet its work and/or expenditure obligations under permits and licences, this may lead to dilution of its interest in, or the loss of, such permits and licences. Such dilution of interest or loss of permits or licences would reduce the attractiveness of the Group's exploration portfolio to existing and potential investors.

It is also possible that the Group may be unable to comply with the terms or requirements of the licences it holds, including the meeting of specified deadlines for prescribed tasks and other obligations set out in the work programmes attached to the licences, in circumstances that entitle the relevant authority to suspend or withdraw the terms of such licences. Non-compliance with these obligations may give rise to enforcement action by the relevant authorities, who may agree to waivers and extensions or may require remedial action but who may also be entitled to revoke the licences in such circumstances.

The terms of the Ruvuma PSA required two wells to be drilled on the Lindi Licence, which expired in January 2018 and the Company will not seek an extension in respect of the licence. Although the wells have not been drilled, the Group has met the minimum expenditure for the Lindi Licence. If the Tanzanian authorities require two exploration wells to be drilled on the Lindi Licence, the Farm-Out Agreement clarifies that Zubair will not be liable for any costs related to such wells as it is not farming into the Lindi Licence. Consequently, Aminex would be required to bear the costs and expenses of such wells in proportion to its participating interests prior to Completion (i.e. 75 per cent.). The Company will not undertake the spudding of any wells on the Lindi Licence within the 12 month period from the date of this Circular.

An addendum to the Ruvuma PSA was entered into between the Tanzanian Government, the TPDC and Ndovu on 28 January 2014, pursuant to which Ndovu agreed to grant security of up to 15 per cent. of additional Profit Gas from the Kiliwani North Development Licence to the Tanzanian Government in the event that the work commitments for the Ruvuma PSA are not fulfilled, such security to be met by the partners in the Ruvuma PSA in accordance with their Participating Interests in the Ruvuma PSA. While Zubair is farming into the Ruvuma PSA, it will not have a participating interest in the Kiliwani North Development Licence. Consequently, Aminex's interest in the Kiliwani North Development Licence is exposed to Zubair or APT, as operator of the Ruvuma PSA, not fulfilling work commitments for the Ruvuma PSA.

The Group's success depends upon its senior management and its skilled technical personnel

Aminex believes that the Group's future success will *inter alia* depend upon the expertise and continued service of certain key executives and technical personnel, including the Executive Directors. Although employment arrangements have been entered into with each of the Group's key personnel to secure their services, the Group cannot guarantee the retention of such key executives and technical personnel.

Should key personnel leave or should the Group be unable to attract and retain skilled and qualified personnel, the Group's business, its results of operations and financial condition may be adversely affected.

Political, social and economic instability may affect Aminex and, following Completion, the Group, their respective operations and personnel

There are inherent risks in foreign operations in the oil and gas industry, including in jurisdictions such as Tanzania and Egypt. As a result, members of the Group may be subject to political, economic and other uncertainties, including, but not limited to, terrorism, military repression, war, piracy, unrest or earthquakes, changes in law, energy policies and regulation or in the personnel administering them, nationalisation or expropriation of property, foreign exchange rates and restrictions, currency instability or non-convertibility, high rates of inflation, royalty and tax increases, changes in policies or laws governing foreign ownership and the operations of foreign-based companies, inability to enforce or cancellation or modification of contractual rights and other risks arising out of foreign governmental sovereignty over the areas in which the Group's operations are conducted.

In the event of a dispute arising in connection with its foreign operations, members of the Group may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdiction of the courts in the relevant member of the Group's home jurisdiction or foreign jurisdictions. Further, members of the Group may have difficulty, or may be unable to enforce awards or judgments obtained in courts or tribunals against foreign entities.

In addition, jurisdictions in which members of the Group operate may have relatively less developed legal systems than in more established economies. This could result in risks such as (i) effective legal redress in the courts of such jurisdictions, whether in respect of a breach of law or regulation, or in an ownership dispute, being more difficult to obtain; (ii) a higher degree of discretion on the part of governmental authorities; (iii) the lack of judicial or administrative guidance on interpreting applicable rules and regulations; (iv) inconsistencies or conflicts between and within various laws, regulations, decrees, orders and resolutions; or (v) relative inexperience of the judiciary and courts in such matters. The commitment of local business people, government officials and agencies and the judicial system in the jurisdictions in which the Company's assets are located to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to the Company's licences and agreements for business. These may be more susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance that licences, licence applications or other legal arrangements will not be adversely affected by the actions of government authorities or others and the effectiveness of and enforcement of such arrangements in these jurisdictions cannot be assured.

Litigation could adversely affect the Group's business, results of operations or financial condition

Members of the Group may, from time to time, face the risk of litigation in connection with its business. Recovery may be sought against members of the Group for very large and/or indeterminate amounts and the existence and scope of liability may remain unknown for substantial periods of time. Substantial legal liability in the future could have a material adverse effect on the Group's business, results of operations and/or financial condition.

The Group is subject to foreign currency risk

The Group's results of operations are affected by movements in exchange rates, particularly movements in the value of Sterling and the euro against the US Dollar, the reporting currency of the Group. While this is mitigated somewhat by the fact that the US Dollar is the currency most commonly used in the pricing of petroleum commodities, the Group's results of operations could be adversely or positively affected by movements in exchange rates, given that a proportion of the Group's costs are denominated in Sterling and/or euro.

Fluctuations in interest rates may indirectly adversely or positively affect interests in projects

Any future borrowings of the Group or its joint ventures are likely to be reliant on project cash flows for their servicing and repayment. Fluctuations in interest rates may adversely or positively affect the Group's cash available for investment and consequently its working interests in projects.

Aminex may be subject to change in tax law

Any change in Aminex's tax status (or that of other members of its Group) or taxation legislation could affect the Company's ability to provide returns to Shareholders and/or alter post tax returns to Shareholders. The taxation of an investment in Aminex depends on the individual circumstances of investors.

Tax regimes in certain jurisdictions in which the Group has a presence may be subject to differing interpretations and are often subject to legislative change and changes in administrative interpretation. Such changes may be implemented with retrospective effect. As a result, the Group may be challenged by tax authorities and any profits from activities in those jurisdictions where it is challenged may be assessed to additional tax.

The nature of the Group's operations exposes it to a wide range of significant health, safety, security and environment (HSSE) risks

The HSSE risks to which members of the Group are potentially exposed cover a wide spectrum, given the geographic range and technical complexity of the Group's daily operations. The location of the Group's operations potentially exposes it to the risk, amongst others, of major process safety incidents, effects of natural disasters, social unrest, personal health and safety and crime. If a major HSSE risk materialises, such as an explosion or hydrocarbon spill due to a process safety incident, this could result in injuries, loss of life, environmental harm, disruption to business activities and, depending on their cause and severity, may adversely affect the Group's business, its results of operations and financial condition.

The Group's investment in joint ventures may reduce its degree of control, as well as its ability to identify and manage risks

The majority of the Group's projects and operations are conducted through joint ventures. This means that the Group has less influence over and control of the behaviour, performance and cost of operations than if it were to hold a 100 per cent. interest. The Group may be unable to undertake certain activities because of opposition from a joint venture partner, or it may experience delays in undertaking activities due to the time taken to obtain the necessary joint venture consent. Additionally, the Group's partners or members of a joint venture or associated company may not be able to meet their financial or other obligations to the projects, threatening the viability of a given project. As a result, the Group's business, its results of operations and financial condition may be adversely affected.

An erosion of the business and operating environment in Tanzania could adversely impact the Group's financial position

The majority of the Group's exploration assets are located in Tanzania. The Group faces various risks in its Tanzanian operations that could adversely impact its financial position. These risks include security issues surrounding the safety of the Group's employees and operations, the Group's ability to enforce existing contractual rights, limited infrastructure and potential legislation that could increase taxes or otherwise led to asset impairment.

Tanzania and surrounding countries have lower levels of economic and state development than some other jurisdictions where oil and gas exploration and production companies operate. This could result in significant difficulties securing infrastructure and services in a timely and cost effective manner required to implement Aminex's exploration and development plans.

The Group's exploration activities may be impaired due to the condition of infrastructure in Tanzania. In general, Tanzania's physical infrastructure, including power generation and transmission stations, communication systems and road network are comparatively less developed. Any failure to maintain or improve adequate transport services and networks or any disruption to transport services could cause delays to the Group's exploration activities.

Any government action concerning the economy, including the oil and gas industry (such as a change in oil or gas pricing policy, domestic supply obligation or taxation rules or practice, or renegotiation or nullification of existing concession contracts or oil and gas exploration policy, laws or practice), could have a material adverse effect on Aminex.

The Group may experience unexpected shutdowns at its facilities

Mechanical problems, accidents, oil or gas leaks or other events at the Group's facilities may cause an unexpected production shutdown of the affected wells. Any unplanned production shutdown of the Group's facilities could have a material adverse effect on the Group's business, financial condition and results of operations.

PART III

PRINCIPAL TERMS OF THE FARM-OUT AGREEMENT

The Farm-Out Agreement was entered into on 11 July 2018 between Ndovu, Aminex and Zubair and is the principal agreement in respect of the sale of the Assigned Interest by Ndovu. A deed of amendment to the Farm-Out Agreement was entered into on 21 November 2018 which extended the long stop date for Completion to 31 March 2019. The following is a summary of the principal terms of the Farm-Out Agreement.

1. Transfer of the Assigned Interest

Subject to the terms and conditions of the Farm-Out Agreement, Ndovu agrees (i) to transfer the Assigned Interest to the Farmee and (ii) to transfer the operatorship under the JOA in respect of the Ruvuma PSA to the Farmee. As a result, following Completion (but before any exercise by the Tanzanian Government of its right to participate under the Ruvuma PSA), the Participating Interests of each of participants in the Ruvuma PSA are expected to be as follows:

Contractor	*Participating Interest*
Farmee	50%
Ndovu	25%
Solo Oil	25%

2. Conditions precedent

The Farm-Out Agreement is conditional upon a number of matters being either satisfied or (where applicable) waived, including:

- approvals by the Tanzanian Government and by Solo Oil of the transfers of the Assigned Interest and of the operatorship under the JOA to the Farmee;
- any other third party consents and approvals required under the documents being obtained in respect of the transfer of the Assigned Interest;
- the Mtwara Licence being granted in a form satisfactory to both Ndovu and the Farmee;
- the shareholders of the Company passing a resolution in general meeting to approve the sale by Ndovu of the Assigned Interest to the Farmee;
- there being no material failures (within the Ruvuma Area) to comply with applicable environmental laws/regulations or good oilfield practices relating to environmental matters identified in any environmental assessment/baseline study undertaken by a firm of suitably qualified and experienced environmental consultants for the Farmee; and
- any operational agreements being transferred to the Farmee or terminated at no cost to the Farmee.

Ndovu and the Farmee have the right to terminate the Farm-Out Agreement if the conditions are not satisfied (or waived), by 5.00pm on 31 March 2019. Completion is to take place on the fifth business day after the satisfaction (or, where applicable, waiver) of all the conditions. In addition, Ndovu may terminate the Farm-Out Agreement in the event that the taxes and other charges payable by Ndovu in respect of the sale of the Assigned Interest exceed an amount agreed between the parties.

3. Carry Work Programme and transfer back of Assigned Interest

Pursuant to the Farm-Out Agreement, the Farmee agrees to perform the Carry Work Programme and to use all reasonable endeavours to spud the Chikumbi-1 well as soon as reasonably practicable after Completion. If, upon completion of the Carry Work Programme, the operating committee fails to approve a field development plan and the Farmee notifies Ndovu that it wishes to withdraw from the Ruvuma PSA and the JOA, then the Farmee shall transfer the Assigned Interest back to Ndovu for no consideration. In such event, the Farmee's obligations under the Carry shall cease and Ndovu shall be responsible for any taxes, fees, costs and expenses relating to such transfer.

Pursuant to the Farm-Out Agreement, Ndovu has agreed that should the Tanzanian Government or the TPDC include within the Mtwara Licence a work commitment to drill up to two exploration wells, then the costs and expenses of such wells shall be borne in accordance with their respective Participating Interests and those costs and expenses shall not form part of the Carry. Notwithstanding this, the Chikumbi-1 well is expected to be an exploration well and would meet one of the exploration well commitments with the Company fully carried, reducing its exposure to its Participating Interest of the remaining exploration well. The Company does not expect such work commitments to be required to be completed within the 12 month period from the date of this Circular.

4. Consideration

The consideration payable under the Farm-Out Agreement is as follows:

- ***Cash consideration at Completion***: US$3 million to be paid in cash by the Farmee to Ndovu at Completion.
- ***Deferred cash payment***: US$2 million to be paid by the Farmee to Ndovu 180 calendar days after the date of Completion.
- ***Carry consideration***: The Farmee will pay Ndovu's Participating Interest share of the charges, costs, expenses or Liabilities incurred or arising under the Contract, the JOA or any other document (including without limitation, Ndovu's Participating Interest share of the charges, costs, expenses and Liabilities arising in respect of or related to the Carry Work Programme) from the Effective Date. The amount of money that the Farmee undertakes to spend in discharging this shall be capped at US$35 million (the "**Carry**").

In the event that production commences from the Ruvuma Area, then:

- for so long as petroleum operations remain cash-flow negative, Ndovu has agreed that its Participating Interest share of any cost hydrocarbons recovered under the Ruvuma PSA may be applied by the Farmee towards Ndovu's share of the costs of petroleum operations within the Ruvuma Area, with any excess being met from the Carry; and
- in the event that Ndovu's Participating Interest cumulative share of the charges, costs, expenses and Liabilities is less than the Carry, then the Farmee shall pay to Ndovu an amount equal to one quarter of the Farmee's Participating Interest share of any profit hydrocarbons recovered under the Ruvuma PSA.

5. Interim period undertakings by Ndovu

In respect of the period commencing on the Effective Date and ending on Completion:

- Ndovu will notify the Farmee and provide details upon the occurrence of:
  - any written notice of default or termination received or given by Ndovu with respect to the Ruvuma PSA or the JOA;
  - any written notice of any pending or threatened claim, demand, action, suit, inquiry or proceeding related to the Ruvuma PSA or the JOA;
  - any material damage, destruction or loss to major assets under the Ruvuma PSA or the JOA; or
  - any event or condition between the date of the Farm-Out Agreement and Completion that (i) would have a material adverse effect on the business, operations, financial conditions or results of operations under the Ruvuma PSA or JOA, taken as a whole; or (ii) would render impossible the Farmee's right to the Assigned Interest; and
- Ndovu agrees to consult with the Farmee before voting on all decisions under the JOA and the Ruvuma PSA.

6. Warranties

The parties have given customary warranties to one another in connection with the Farm-Out Agreement, all of which will be deemed to be repeated at Completion. Ndovu's liability under these warranties is subject to certain limitations.

7. Effective economic date and historic cost recoveries

The parties have agreed that the Effective Date shall be the effective economic date of the transaction. Accordingly:

- Ndovu has agreed to indemnify the Farmee against all liabilities which are attributable (on an accruals basis) to the Assigned Interest prior to (but not including) the Effective Date
- The Farmee has agreed to indemnify Ndovu against all liabilities which are attributable (on an accruals basis) to the Assigned Interest on and from the Effective Date

The parties have also agreed that any cost recoveries made under the Ruvuma PSA shall be shared between them in accordance with their Participating Interests under the JOA (irrespective of when the relevant costs were incurred and irrespective of whether those costs were the subject of the Carry).

8. Indemnities

Pursuant to the Farm-Out Agreement, Ndovu has agreed to indemnify the Farmee, with effect from Completion, against any liabilities arising from:

- the Ruvuma PSA Addendum which is an addendum to the Ruvuma PSA that was entered into between the Tanzanian Government, the TPDC and Ndovu on 28 January 2014, pursuant to which Ndovu agreed to grant security to the Tanzanian Government and the TPDC over Ndovu's and its partner's, Solo Oil, Profit Gas interests in the Kiliwani North Development Licence in the event that the work commitments for the Ruvuma PSA are not fulfilled;
- any integrity issues in respect of well NT-1 drilled previously within the Ruvuma PSA, save where any such liabilities arise from any work-over of or other intervention undertaken in, such well after Completion;
- any operational agreements entered into by Ndovu or any prior operator;
- the condition of any equipment used on petroleum operations, save where such liabilities arise from the use or intervention with such equipment by the Farmee after completion;
- any claim by the Tanzanian Government or the TPDC relating to pre-Effective Date work commitments which the Tanzanian Government or the TPDC consider have not been completed. In this connection, the parties have however agreed that if any requirement is included within the Mtwara Licence to drill up to two exploration wells, then the costs and expenses of such wells shall be borne in accordance with their respective Participating Interests (and those costs and expenses shall not form part of the Carry); and
- any claim by the Tanzanian Government or the TPDC arising from any enquiry, investigation or audit in respect of any act or omission by Ndovu.

9. Parent company guarantees

Aminex will guarantee all of Ndovu's obligations under the Farm-Out Agreement. If Zubair assigns its rights and obligations under the Farm-Out Agreement to an affiliate, then Zubair will guarantee all of its affiliate's obligations under the Farm-Out Agreement.

10. Governing law and dispute resolution

The Farm-Out Agreement is governed by English Law. The parties have agreed that any disputes arising out of or in connection with the Farm-Out Agreement shall be determined by arbitration in London by one arbitrator pursuant to the arbitration rules of the London Court of International Arbitration.

PART IV

FINANCIAL INFORMATION RELATING

TO THE RUVUMA PSA

1. Basis of financial information

The following financial information relating to the Ruvuma PSA has been extracted without material adjustment from the consolidation schedules which underlie the consolidated audited accounts for the Group for the three years ended 31 December 2015, 2016 and 2017 and the unaudited interim financial information for the Group for the six months ended 30 June 2018. Shareholders should read the whole of this Circular and not rely solely on the financial information contained in this Part IV. The financial information contained in Sections 2 and 3 of this Part 4 relates to the accounting periods in which Aminex's assets included a 75 per cent. participating interest in the Ruvuma PSA. Therefore, the financial information relates to both the 50 per cent participating interest proposed to be disposed of in the Transaction and the remaining 25 per cent participating interest to be retained by the Company post Completion. The financial information contained in this Part IV has been prepared solely for the purposes of this document and does not constitute statutory financial statements within the meaning of the Companies Acts. The statutory accounts for the Group in respect of each of the three financial years ended 31 December 2015, 2016 and 2017 have been delivered to the Registrar of Companies. The financial information in Sections 2 and 3 of this Part IV has been prepared using the IFRS accounting policies used to prepare the consolidated financial statements of the Group for the 12 months ended 31 December 2017.

2. Income Statements for the three years ended 31 December 2015, 2016 and 2017 and the six months ended 30 June 2018

	Unaudited Six months ended 30 June 2018	*Unaudited Year ended 31 December 2017*	*Unaudited Year ended 31 December 2016*	*Unaudited Year ended 31 December 2015*
	US$'000	*US$'000*	*US$'000*	*US$'000*
Revenues	–	–	–	–
Profit/(loss) from operating activities	**–**	**–**	**–**	**–**
Finance costs(1)	(15)	(33)	(16)	(14)
Income tax expense	–	–	–	–
Profit/(loss) for the financial period	**(15)**	**(33)**	**(16)**	**(14)**

(1) The finance costs relate to the unwind of the decommissioning provision for wells on the Ruvuma PSA

3. Historical Balance Sheet

	Unaudited 30 June 2018	*Unaudited 31 December 2017*
	US$'000	*US$'000*
Assets		
Non-current assets		
Exploration and evaluation assets	53,267	52,488
Total non-current assets	**53,267**	**52,488**
Current assets		
Trade and other receivables	1,008	721
Cash and cash equivalents	141	741
Total current assets	**1,149**	**1,462**
Total assets	**54,416**	**53,950**
Equity		
Issued capital	–	–
Retained earnings	(91)	(76)
Total equity	**(91)**	**(76)**
Liabilities		
Non-current liabilities		
Decommissioning provision	304	289
Amounts due to Group undertakings	53,402	52,909
Total non-current liabilities	**53,706**	**53,198**
Current liabilities		
Trade and other payables	801	828
Total current liabilities	**801**	**828**
Total liabilities	**54,507**	**54,026**
Net equity and liabilities	**54,416**	**53,950**

PART V

PRO FORMA FINANCIAL INFORMATION ON THE GROUP

Section A: Unaudited Pro Forma Statement of Net Assets of the Group

The following unaudited pro forma statement of net assets of the Group has been prepared under IFRS, in accordance with the Group's accounting policies as set out in its Annual Report for the period ended 31 December 2017 and on the basis of the notes set out below to illustrate how the Transaction might have affected the balance sheet of the Group as shown in its unaudited financial statements for the 6 months to 30 June 2018 had it been undertaken at that date. The pro forma financial information has been prepared for illustrative purposes only and because of its nature only addresses a hypothetical situation and, therefore, does not represent the actual financial position of the Group. The pro forma statement of net assets has been prepared in accordance with paragraph 10.3.3 of the Listing Rules of the Euronext Dublin and paragraph 13.3.3R of the Listing Rules of the Financial Conduct Authority.

	Unaudited 30 June 2018[(1)]	*Adjustments to account for the Transaction*	*Adjustments to account for Transaction related fees*[(5)]	*Pro Forma for the Group*[(6)]
	US$'000	*US$'000*	*US$'000*	*US$'000*
Assets				
Non-current assets				
Exploration and evaluation assets	100,710	(5,000)[(4)]	–	95,710
Property, plant and equipment	2,406	–	–	2,406
Total non-current assets	**103,116**	**(5,000)**	**–**	**98,116**
Current assets				
Trade and other receivables	9,806	2,000[(2)]	–	11,806
Cash and cash equivalents	2,650	3,000[(3)]	(350)	5,300
Total current assets	**12,456**	**5,000**	**(350)**	**17,106**
Total assets	**115,572**	**–**	**(350)**	**115,222**
Equity				
Issued capital	69,062	–	–	69,062
Share premium	122,267	–	–	122,267
Other undenominated capital	234	–	–	234
Share option reserve	2,710	–	–	2,710
Foreign currency translation reserve	(1,939)	–	–	(1,939)
Retained earnings	(86,499)	–	(350)	(86,849)
Total equity	**105,835**	**–**	**(350)**	**105,485**
Liabilities				
Non-current liabilities				
Decommissioning provision	668	–	–	668
Total non-current liabilities	**668**	**–**	**–**	**668**
Current liabilities				
Trade and other payables	9,069	–	–	9,069
Total current liabilities	**9,069**	**–**	**–**	**9,069**
Total liabilities	**9,737**	**–**	**–**	**9,737**
Net equity and liabilities	**115,572**	**–**	**(350)**	**115,222**

Notes:

1. The financial information in respect of the Group has been extracted without material adjustment from the unaudited financial statements of the Group for the six months ended 30 June 2018 prepared in accordance with IFRS.
2. The adjustment recognises a debtor of US$2 million for the second tranche due 180 days after the Farm-Out Completion Date.
3. The adjustment recognises the receipt of the first tranche of US$3 million due on completion of the Farm-Out, increasing cash and cash equivalents.
4. The total cash and cash receivable consideration of US$5 million reduces the carrying value of the Group's intangible fixed assets related to the Ruvuma PSA. The carrying value of the Group's intangible fixed assets is not expected to be impacted by the Carry Work Programme unless Aminex's share of costs exceed US$35 million. Aminex is carried for a maximum of US$35 million under the terms of the Farm-Out Agreement.
5. The adjustment reflects expenses pursuant to the Transaction amounting to US$0.35 million being charged to retained earnings.
6. No account has been taken of the trading results of the Group since 30 June 2018 and management is of the opinion that the Transaction will not give rise to an impairment in the carrying value of exploration and evaluation assets.

Section B: Report on the Unaudited Pro Forma Statement of Net Assets of the Group

KPMG

KPMG
Chartered Accountants
1 Stokes Place
St. Stephen's Green
Dublin 2
Ireland

The Directors
Aminex PLC
6 Northbrook Road
Dublin 6

7 December 2018

Dear Sirs

We report on the unaudited pro forma statement of net assets for the Group (the "Pro forma financial information") set out in Part V of the Class 1 circular dated 7 December 2018, which has been prepared on the basis described in notes 1 to 6, for illustrative purposes only, to provide information about how the proposed disposal of a 50 per cent. interest in the Ruvuma PSA might have affected the financial information presented on the basis of the accounting policies adopted by Aminex PLC in preparing the interim financial statements for the period ended 30 June 2018. This report is required by paragraph 10.3.3 of the Listing Rules of the Euronext Dublin and paragraph 13.3.3R of the Listing Rules of the Financial Conduct Authority and is given for the purpose of complying with those requirements and for no other purpose.

Responsibilities

It is the responsibility of the directors of Aminex PLC to prepare the Pro forma financial information in accordance with paragraph 10.3.3 of the Listing Rules of the Euronext Dublin and paragraph 13.3.3R of the Listing Rules of the Financial Conduct Authority.

It is our responsibility to form an opinion, as required by paragraph 7 of Annex II of the Prospectus Directive Regulation, as to the proper compilation of the Pro forma financial information and to report that opinion to you.

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.

Save for any responsibility which we may have to those persons to whom this report is expressly addressed and which we may have to ordinary shareholders as a result of the inclusion of this report in the Class 1 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 10.4.1 (6) of the Listing Rules of the Euronext Dublin and Listing Rule 13.4.1R(6) of the Listing Rules of the Financial Conduct Authority, consenting to its inclusion in the Class 1 circular.

Basis of Opinion

We conducted our work in accordance with the Standards for Investment Reporting issued by the Auditing Practices Board of the United Kingdom and Ireland. 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 of Aminex PLC.

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 Aminex PLC.

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

Opinion

In our opinion:

- the Pro forma financial information has been properly compiled on the basis stated; and
- such basis is consistent with the accounting policies of Aminex PLC.

Yours faithfully
KPMG
Chartered Accountants
Dublin, Ireland

PART VI

ADDITIONAL INFORMATION

1. THE COMPANY

Aminex was incorporated and registered in Ireland on 23 November 1979 with registered number 72399, as a public limited company under the Companies Acts, 1963 to 1977 and is domiciled in Ireland. The principal legislation under which the Company operates is the Companies Act and the regulations made thereunder. The registered office of the Company is at 6 Northbrook Road, Dublin 6, Ireland (Tel: +353 1 4959200) and its UK representative office is at Kings Buildings, 16 Smith Square, London SW1P 3JJ, England (Tel: +44 20 3198 8415).

2. RESPONSIBILITY

The Company and the Directors of the Company (whose names appear in Section 3 below) 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.

3. DIRECTORS' INTERESTS

The table below sets out the direct and indirect interests of the Directors (and of persons connected with them) in the share capital of the Company as at the Latest Practicable Date:

Name of Director	*Number of Ordinary Shares*	*% of Existing Issued Share Capital*
K.J. Phair	9,019,401	0.25
J.C. Bhattacherjee	46,406,815	1.27
M.V. Williams	4,484,648	0.12
J. Bell	–	–
T.A. Mackay	1,028,947	0.03
O. Fjeld	–	–
S. Al-Ghaithi	–	–

As at the Latest Practicable Date, the Directors hold the following Options granted pursuant to the Share Option Scheme:

Name of Director	*Options held*	*Options price*	*Exercisable between*	
K.J. Phair	200,000	Stg8.5p	Jan-10	Jan-20
	6,000,000	Stg1.34p	May-16	May-19
M.V. Williams	1,000,000	Stg8.5p	Jan-13	Jan-20
	29,000,000	Stg1.34p	May-16	May-19
	7,000,000	Stg3.08p	Jan-18	Jan-21
J.C. Bhattacherjee	30,000,000	Stg1.34p	May-16	May-19
	8,000,000	Stg3.08p	Jan-18	Jan-21
J. Bell	2,000,000	Stg3.08p	Jan-18	Jan-20
T.A. Mackay	6.000,000	Stg1.34p	May-16	May-19

No options have been granted to Mr. O. Fjeld and Mr. S. Al-Ghaithi as at the Latest Practicable Date.

4. MAJOR INTERESTS IN SHARES

As at the Latest Practicable Date the Company had been notified of notifiable interests in the Company's issued shares, being holdings equating to at least three per cent. of the Company's issued share capital as set out below:

Shareholder	*Number of Ordinary Shares*	*% of Issued Share Capital*
Eclipse Investments LLC	1,042,636,095	28.62
Majedie Asset management Limited and Majedie Asset Management Investment Fund Company	345,061,624	9.47

Save as detailed in Sections 3 and 4 above, the Company is not aware of any person who as at the Latest Practicable Date) exercises, or could exercise, directly or indirectly, jointly or severally, control over the Company.

5. KEY INDIVIDUALS IN RESPECT OF THE RUVUMA PSA

Aminex does not consider that there are any key individuals important to the Ruvuma PSA.

6. MATERIAL CONTRACTS

6.1 ***Group***

Save for the Farm-Out Agreement described in Part III of the Circular and the Relationship Agreement (a summary of which is incorporated by reference to the 2016 Prospectus), no contracts (other than contracts entered into in the ordinary course of business) have been entered into by the Company or any other member of the Group (i) within the two years immediately preceding the Latest Practicable Date and which are or may be material to the Group; or (ii) which contain any provision under which any member of the Group has any obligation or entitlement which is, or may be, material to the Group as at the Latest Practicable Date.

6.2 ***Ruvuma PSA***

Save as disclosed in Section 6.1 (above), no contracts (other than contracts entered into in the ordinary course of business) have been entered into by the Company or any member of the Group in respect of the Ruvuma PSA (i) within the two years immediately preceding the Latest Practicable Date and which are or may be material in respect of the Ruvuma PSA; or (ii) which contain any provision under which any member of the Aminex Group has, or there otherwise exists, any obligation or entitlement which is, or may be, material in respect of the Ruvuma PSA as at the Latest Practicable Date.

7. RELATED PARTY TRANSACTIONS

Save as disclosed in Note 30 on page 61 of the 2016 Annual Report and in Note 29 on page 60 of the 2017 Annual Report (which are incorporated by reference in this document), no members of the Group entered into related party transactions during any of the financial years ended 31 December 2015, 2016 or 2017, respectively, nor during the period between 1 January 2018 and the Latest Practicable Date.

8. LITIGATION

8.1 ***The Group***

There are not, and have not been, any governmental, legal or arbitration proceedings (including any proceedings which are pending or threatened as far as the Company is aware), during the 12 months immediately preceding the date of this Circular which may have, or have had in the recent past, significant effects on the Company's or the Group's financial position or profitability.

8.2 ***Ruvuma PSA***

There are not, and have not been, any governmental, legal or arbitration proceedings (including any proceedings which are pending or threatened as far as the Company is aware), during the

12 months immediately preceding the date of this Circular which may have, or have had in the recent past, significant effects on the Ruvuma PSA's financial position or profitability.

9. WORKING CAPITAL

The Company is of the opinion that, taking into account existing cash resources and the net proceeds of the Transaction, the Group has sufficient working capital for its present requirements, that is, for at least the 12-month period from the date of this Circular.

10. CONSENTS

10.1 J&E Davy, of Davy House, 49 Dawson Street, Dublin 2, Ireland, which is regulated in Ireland by the Central Bank, has given and has not withdrawn its written consent to the inclusion in this document of its name and references thereto in the form and context in which it appears.

10.2 KPMG, Chartered Accountants and Registered Auditor, 1 Stokes Place, St. Stephen's Green, Dublin 2, Ireland is a member firm of the Institute of Chartered Accountants in Ireland and has given and not withdrawn its written consent to the inclusion of its report set out in "*Pro Forma Financial Information for the Group*" in Part V of this document, and references to its report and its name in the form and context in which they appear.

10.3 RPS Energy Consultants Limited has given and has not withdrawn its written consent to the inclusion of the Competent Person's Report on the Ruvuma PSA set out in "Technical Report" in Part VII, in the form and context in which it appears and RPS Energy has authorised those parts of this document which comprise of its report for the purpose of paragraph 13.4.1 R(6) of the Listing Rules.

11. SIGNIFICANT CHANGE

11.1 ***Group***

There has been no significant change in the financial or trading position of the Group since 30 June 2018 (being the date to which the latest published unaudited interim financial information on Aminex has been prepared).

11.2 ***Ruvuma PSA***

There has been no significant change in the financial or trading position for the operations relating to the Ruvuma Area since 30 June 2018 (being the date to which the latest published unaudited interim financial information on Aminex has been prepared).

12. DOCUMENTS INCORPORATED BY REFERENCE

The 2016 and 2017 Annual Reports and the 2016 Prospectus are on the Company's website at http://aminex-plc.com/FinancialStatements.aspx

The table below sets out the various sections of the 2016 and 2017 Annual Reports and 2016 Prospectus which are incorporated by reference into this Circular so as to provide the information required under the Listing Rules and to ensure that Shareholders and others are aware of all information which, according to the particular nature of Aminex is necessary to enable Shareholders and others to make an informed assessment of the assets and liabilities, financial position, profits and losses and prospects of the Company.

Document	*Section*	*Page Numbers*	*Circular Reference*
2016 Annual Report	Related party transactions	61	Section 7 of Part VI
2017 Annual Report	Related party transactions	60	Section 7 of Part VI
2016 Prospectus	Relationship Agreement	132 – 133	Section 6 of Part VI

The parts of the 2016 and 2017 Annual Reports and 2016 Prospectus other than those incorporated by reference (as per the table above) are either not relevant or covered elsewhere in this Circular. Information that is itself incorporated by reference in the 2016 and 2017 Annual Reports and 2016 Prospectus is not incorporated by reference into this Circular. It should be noted that, except as set forth above, no other parts of the 2016 and 2017 Annual Reports and 2016 Prospectus are incorporated by reference into this Circular.

13. DOCUMENTS AVAILABLE FOR INSPECTION

Copies of the following documents will be available for inspection during normal business hours on any weekday (Saturday, Sundays and public holidays excepted) at the offices of the Company at Kings Buildings, 16 Smith Square, London SW1P 3JJ, United Kingdom and at the offices of ByrneWallace, 88 Harcourt Street, Dublin 2, Ireland up to and including the date of the Extraordinary General Meeting:

(a) the Memorandum and Articles of the Company;

(b) the report from RPS Energy Consultants Limited set out in Part VII of this document;

(c) KPMG's report on the pro forma financial information set out in Part V of this document;

(d) the audited consolidated accounts of Aminex for the three financial years ended 31 December 2015, 31 December 2016 and 31 December 2017, and the unaudited consolidated interim accounts of the Group for the six month period ended 30 June 2018;

(e) the Farm-Out Agreement and Deed of Amendment;

(f) the consent letters referred to under "*Consents*" at Section 10 above;

(g) the Form of Proxy; and

(h) the Circular.

PART VII

TECHNICAL REPORT

Set out on the following pages is the statement of resources data and other oil and gas information in relation to the Ruvuma PSA, effective as of 31 December 2017, prepared in accordance with the PRMS.

Unless stated otherwise, the RPS Report has been prepared in accordance with the standards established by the PRMS. The estimates of resources and value contained in the RPS Report are based on the data set available to, and provided by, Aminex. RPS Energy has accepted, without independent verification, the accuracy and completeness of these data. The data set supplied by Aminex included geological, geophysical and engineering data, together with reports and presentations pertaining to the contractual and fiscal terms applicable to the asset. The data provided by Aminex included management estimates and forward-looking statements, which should not be unduly relied upon. In carrying out its review, RPS Energy relied solely upon this information. The RPS Report, reproduced in its entirety on the following pages, contains the estimates, assumptions and conversion rates used in preparing the resources data.

Estimates of resources are forward-looking statements based on judgements regarding future events that may be inaccurate. See "Forward-looking statements and the risks associated with them". The accuracy of resources estimates and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgement. Shareholders should not therefore place undue reliance on the forward-looking statements in the RPS Report or on the ability of the RPS Report to predict actual resources. This document should be accepted with the understanding that resources and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material and in the event of material revision before the EGM, the Company may be required to publish a supplementary circular.

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

The estimates of oil and gas resources as set out in the Technical Report are based on technical information supplied by the Company to RPS Energy. The technical information supplied by the Company to RPS Energy has not been independently verified by RPS Energy and is the sole responsibility of the management of the Company. All technical information obtained from the Company or from public sources for purposes of the Technical Report has been accepted, without further investigation. It is RPS Energy's opinion that the technical information received from the Company is reasonable, based on similar evaluations prepared by RPS Energy in its experience of the oil and gas industry.

RPS Energy

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ECV2252

4 December 2018

COMPETENT PERSON'S REPORT ON CERTAIN TANZANIAN ASSETS OF NDOVU RESOURCES LTD

Pursuant to a Letter of Engagement dated 23 October 2017 as amended by Amendment 1 (dated 26 January 2018), Amendment 2 (dated 29 June 2018) and Amendment 3 (dated 27 November 2018) thereto (the "Agreement"), with Ndovu Resources Ltd ("Ndovu"), RPS Energy Consultants Limited ("RPS") has completed an audit of the Ruvuma PSA including the Ntorya Development Area on behalf of Ndovu.

This report (the "Report") is issued by RPS and is produced as part of the Services detailed in the Agreement and is subject to the terms and conditions of the Agreement.

Ndovu Resources Ltd is a subsidiary of Aminex PLC. At the request of Ndovu and with the agreement of RPS, the Report is also addressed to Aminex PLC and is only capable of being relied on by Aminex PLC as the owner of Ndovu under and pursuant to (and subject to the terms of) the Agreement.

All Reserves and Resources definitions and estimates shown in this Report are based on the 2018 SPE/AAPG/WPC/SPEE/SEG/SPWLA/EAGE Petroleum Resource Management System ("PRMS"). All Resource estimates have an effective date of 1st December 2018.

No site visits have been undertaken by RPS.

QUALIFICATIONS

RPS is an independent consultancy specialising in petroleum reservoir evaluation and economic analysis. The provision of professional services has been solely on a fee basis. Ms Eleanor Rollett managed the project and Mr Gordon Taylor, Director, Consulting for RPS Energy, has supervised the evaluation. Ms Rollett is a Chartered Geologist with 20 years' experience. Mr Taylor is a Chartered Geologist and Chartered Engineer with over 35 years' experience in upstream oil and gas.

Other RPS employees involved in this work hold at least a Master's degree in geology, geophysics, petroleum engineering or a related subject or have at least ten years of relevant experience in the practice of geology, geophysics or petroleum engineering. Key discipline leaders are also Chartered Geologists or Chartered Engineers.

BASIS OF OPINION

The results presented herein reflect our informed judgement based on accepted standards of professional investigation, but are subject to generally recognised uncertainties associated with the interpretation of geological, geophysical and engineering data. The Services have been conducted within our understanding of petroleum legislation, taxation and other regulations that currently apply to these interests. However, RPS is not in a position to attest to the property title, financial interest relationships or encumbrances related to the properties. Our estimates of resources are based on the data set available to, and provided by, Ndovu. We have accepted, without independent verification, the accuracy and completeness of these data.

Our approach has been to review Ndovu's technical interpretation of geoscience data for the licence for reasonableness and to review the ranges of uncertainty for each parameter around the base case in order to estimate a range of petroleum initially in place and recoverable for the Contingent Resources. Where appropriate, we have estimated P90, P50 and P10 Prospective Resources based on data supplied by Ndovu.

The Report represents RPS's best professional judgement and should not be considered a guarantee or prediction of results. It should be understood that any evaluation, particularly one involving exploration and future petroleum developments, may be subject to significant variations over short periods of time as new information becomes available. As stated in the Agreement, RPS cannot and does not guarantee the accuracy or correctness of any interpretation made by it of any of the data, documentation and information provided by Ndovu or others in accordance with the Agreement. RPS does not warrant or guarantee, through the Services, this Report or otherwise, any geological or commercial outcome.

This Report is prepared as a mineral expert's report in accordance with paragraphs 131 to 133 of the ESMA update (ESMA/2013/319) of the Committee of European Securities Regulators' (CESR) recommendations for the consistent implementation of the Prospectus Directive Regulation EC 809/2004 implementing Prospectus Directive 2003/71/EC (the ESMA Guidelines). This Report is prepared as a mineral expert's report for inclusion by Aminex in a circular in connection with a Class 1 Transaction.

RPS has given and not withdrawn its written consent to the issue of the circular, with its name included within it, and to the inclusion of this Report and references to this Report in the circular. For the purposes of Listing Rule 13.4.1(6) RPS accepts that the RPS Report has been prepared in accordance with and is provided subject to the terms and conditions of the Agreement and declares that to the best knowledge and belief of RPS the information contained herein is in accordance with the facts and does not omit anything likely to affect the import of such information.

This Report relates specifically and solely to the subject assets and is conditional upon various assumptions that are described herein. The Report, of which this letter forms part, must therefore be read in its entirety. Except with permission from RPS, this Report may only be used in accordance with the Agreement.

Yours faithfully,
RPS Energy Consultants Limited

Gordon R Taylor, *CEng, CGeol*
Director, Consulting

1 EXECUTIVE SUMMARY

Ndovu has a portfolio of exploration and production assets in licences in Tanzania. RPS has reviewed the Resources in the Ruvuma PSA for this Report in which Ndovu has a 75% working interest and is operator. The Ruvuma PSA contains the Mtwara licence and the Ntorya development area. The second extension of the Mtwara licence expired in December 2017 and Ndovu is currently negotiating a further extension. Ndovu is also negotiating a 25-year development licence for the Ntorya development for which it made a submission in September 2017.

Ntorya is an undeveloped discovery of gas in a Lower Cretaceous reservoir. RPS has estimated a range of Contingent Resources for the development assuming the development licence is granted. There is a firm initial plan to produce through two existing wells and a third, new, well which Ndovu advise is planned for Q2 2019. If this initial development is successful, an incremental development with a further eight wells may be considered. The initial development is classed as Contingent Resources "Development Pending" and the larger development as Contingent Resources "Development Unclarified". Table 1-1 shows RPS' estimates of Contingent Resources. The new well planned for Q2 2019 well will target a deeper Jurassic prospect, Chikumbi, as well as appraising the Lower Cretaceous discovery. Table 1-2 shows RPS' estimates of Prospective Resources for Chikumbi.

	Gas Contingent Resources (Bscf)[1]									Pd[4] (%)
	Gross (100%) Licence Basis			Ndovu's Net Working Interest Basis[2]			Ndovu's Net Entitlement Basis[3]			
	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Development Pending	26	81	213	19	60	160	16	52	123	75
Development Unclarified	342	682	945	257	512	712	195	354	466	25

1. Assuming Development Licence is ratified
2. Ndovu Working Interest is 75%
3. Ndovu net entitlement is based on Ndovu share of Cost Oil and Profit Oil calculated using the assumed PSA terms.
4. Pd is Chance of Development

Table 1-1: Contingent Resources for Ntorya Development

GIIP (Bscf)[1]			Prospective Resources (Bscf)[1]						Pg[2] (%)
Gross on Licence			Gross on Licence			75% Working Interest			
1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
589	1,351	2,522	399	936	1,798	299	702	1,350	8

1. Assuming Development Licence is ratified
2. Pg is Chance of Geological Discovery

Table 1-2: GIIP and Prospective Resources in Chikumbi Prospect (below Ntorya Development)

Additional prospectivity exists on the Mtwara licence of the Ruvuma PSA for which Ndovu is currently negotiating a licence extension. For completeness Ndovu has requested that RPS tabulate Prospective Resources estimated by other consultancies (RISC in 2012[1] and Senergy in 2015[2]).

1 Nyuni Area PSA Technical Evaluation, RISC Consultants, June 2012

2 Competent Persons Report Resource Assessment of Assets of Aminex in Tanzania, Senergy, May 2015

There are a number of leads as defined by Senergy and RISC in the Ruvuma PSA. Senergy evaluated the high graded leads as shown in Table 1-3. Additional leads reviewed by RISC are shown in Table 1-4. RPS considers the Senergy evaluation of the high graded leads in the Ruvuma licence to be reasonable.

Lead	GIIP (Bscf)[1]			Prospective Resources (Bscf)[1]						Pg[2] (%)
	Gross on Licence			Gross on Licence			75% Working Interest			
	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
Namisange	81	467	2,762	56	325	1,925	42	244	1,444	8
Likonde Updip	57	239	1,006	39	166	702	29	125	527	10

1. Assumes PSA term is extended
2. Pg is Chance of Geological Discovery

Table 1-3: Prospective Resource Resources of High-graded Leads (Senergy 2015)

Lead	GIIP (Bscf)[1]			Prospective Resources (Bscf)[1]						Pg[2,3] (%)
	Gross on Licence			Gross on Licence			75% Working Interest			
	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
Ziwani NW	n/a	n/a	n/a	8	35	153	6	26	115	<5%
Ziwani SW	n/a	n/a	n/a	12	54	236	9	41	177	<5%

1. Assumes PSA term is extended
2. RPS assessment of Pg (RISC did not include risking)
3. Pg is Chance of Geological Discovery

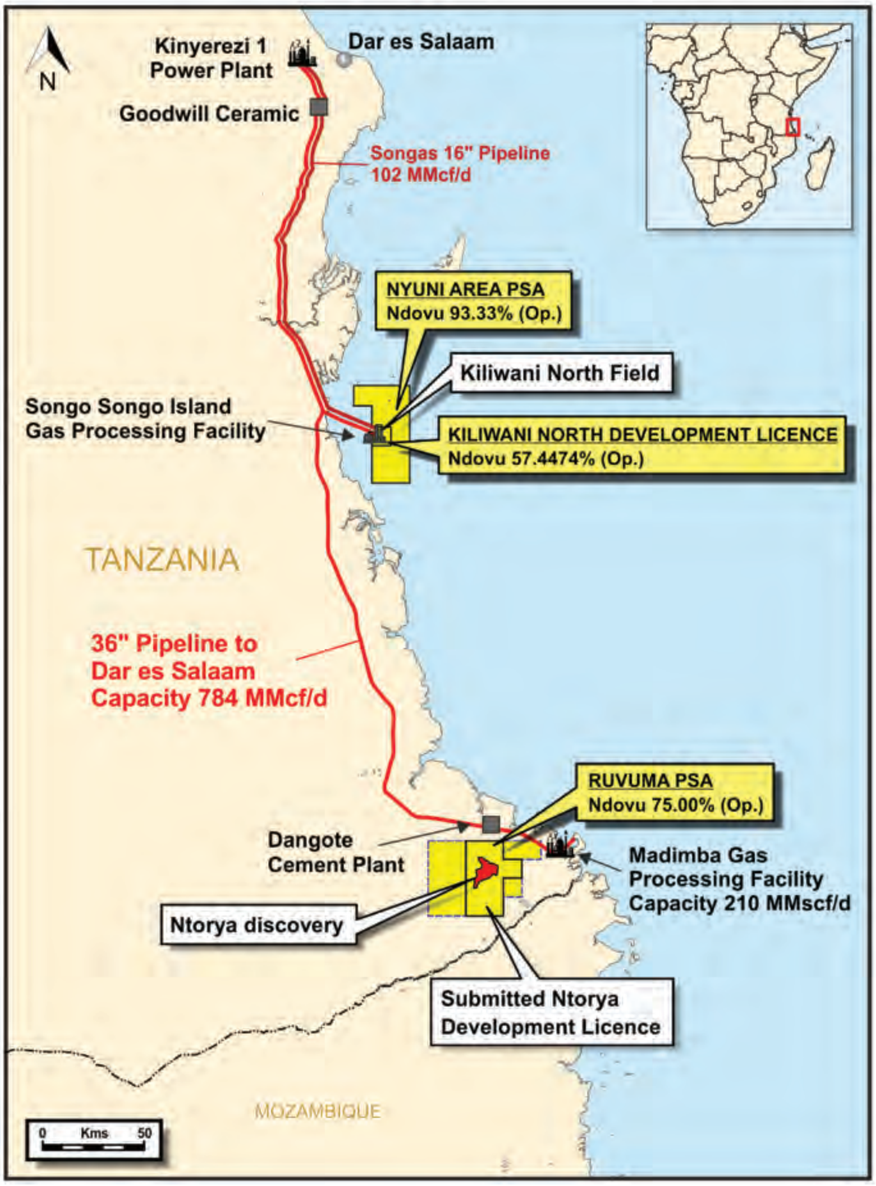
Table 1-4: Prospective Resources of Other Leads (RISC 2012)

2 INTRODUCTION

2.1 *Description of Assets*

Ndovu has a portfolio of exploration and production assets in Tanzania including the Ruvuma PSA. This Report only addresses the Ruvuma PSA. The locations of the licences are shown in Figure 2-1.

Ndovu Resources Ltd is a wholly owned subsidiary of Aminex PLC. Aminex has provided data and interpretations to RPS on behalf of Ndovu.



Source: Ndovu

Figure 2-1: Location of Ndovu's Licences

The Ruvuma PSA consists of the Mtwara licence (Figure 2-2). It is located onshore, immediately to the north of the Mozambique border.

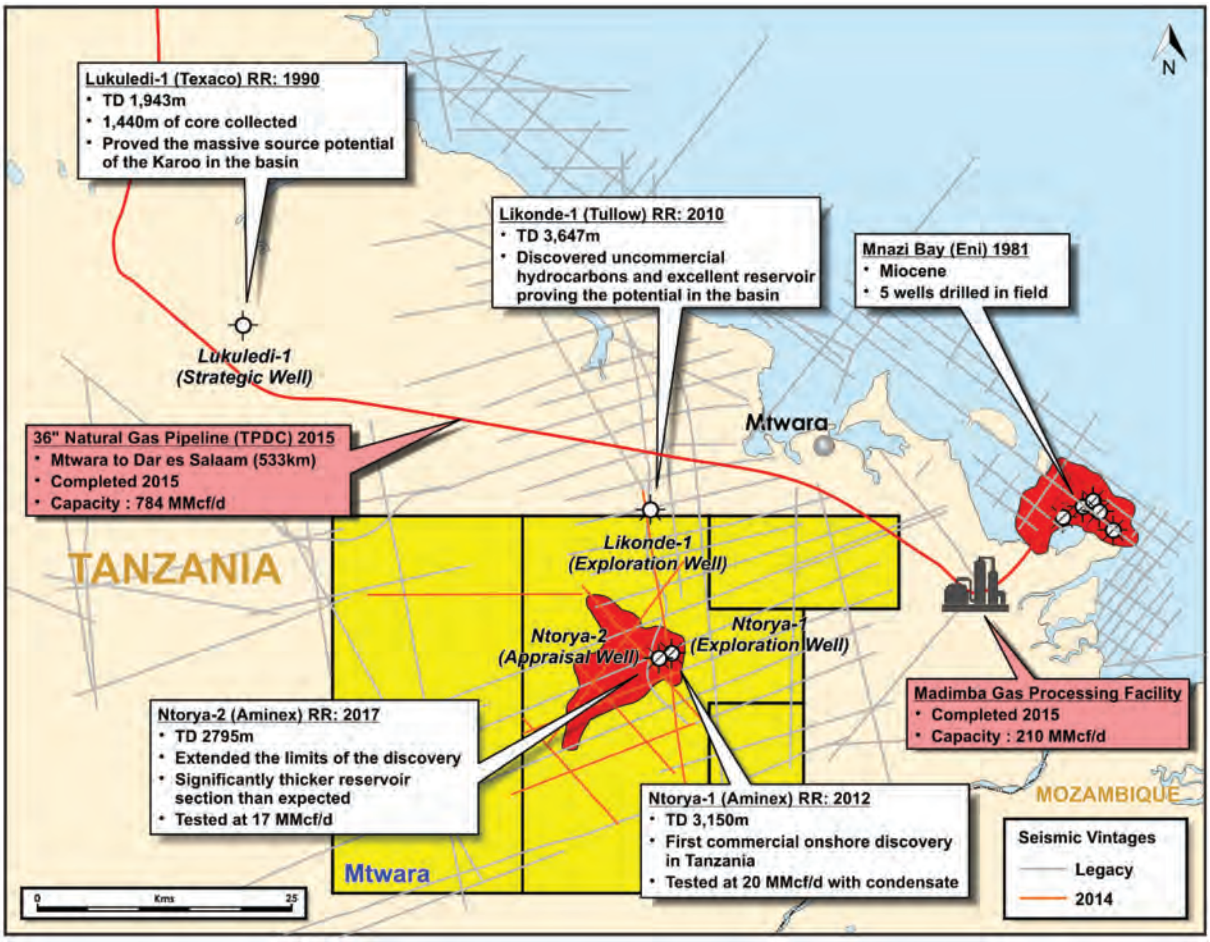
Details of the Ruvuma PSA are given in Table 2-1. Ndovu has a 75% working interest and is operator; Solo Oil has the remaining 25%.

The Mtwara licence has expired. Ndovu is currently in negotiation to extend the Mtwara licence and in September 2017, submitted an application for a Development Licence for Ntorya. Ndovu has advised RPS that it has reasonable expectations of securing the licence over the expired licence area and is awaiting a response on the Development Licence.

This Report is based on the assumption that the licence is awarded. However, RPS does not opine on the likelihood of Ndovu securing the licence and the evaluation in this Report should not be taken as an indication that the licence will be secured by Ndovu.

PSA	Licence	Area (sq. km)	Ndovu Equity	Awarded	Licence Status
Ruvuma	Mtwara	1,682	75%	October 2005	Second extension expired 08/12/2017 Ndovu is negotiating a further extension
	Ntorya Development	757[1]	75%	Negotiating	Ndovu is negotiating a 25-year licence
1. To be carved out from the Mtwara licence					

Table 2-1: Summary of Licences



Source: Ndovu

Figure 2-2: Ruvuma PSA and Mtwara Licence

In this Report RPS has assumed that the fiscal terms of a Development Licence or extended PSA will be the same as the terms negotiated for the Kiliwani North Gas Sales Agreement (see Section 5.9), as Ndovu advise the terms are expected to be similar.

2.2 *Exploration History*

Two exploration wells (Likonde-1 drilled in 2010 and Ntorya-1 drilled in 2012) and one appraisal well (Ntorya-2 drilled in 2017) have been drilled in the PSA area. Both Ntorya-1 and Ntorya-2 successfully tested gas with flow rates of 20 MMscf/d and 17 MMscf/d respectively. Likonde-1 encountered gas shows.

Sparse multi-vintage (2005, 2007, 2014) 2D seismic covers the area with line length totalling 2,955 km. Overall data quality is poor. Ndovu plans to acquire approximately 217 sq. km of 3D seismic over the proposed Ntorya development area. Ndovu has planned an additional 2D survey over the entire Mtwara licence.

3 METHODS USED IN THIS REPORT

3.1 *Reserves and Resource Classification*

Reserves and Resources are estimated in line with the 2018 PRMS guidelines[3] which are summarised in Appendix B.

In estimating Reserves and Resources, we have used appropriate industry standard petroleum engineering techniques.

Hydrocarbon Resource and Reserve estimates are expressions of judgement based on knowledge, experience and industry practice and are restricted to the data made available. They are, therefore, imprecise and depend to some extent on interpretations, which may prove to be inaccurate. Estimates that were reasonable when made may change significantly when new information from additional exploration or appraisal activity becomes available.

3.1.1 *Contingent Resources*

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be subclassified based on project maturity and/or economic status.

Development projects and associated recoverable quantities may be subclassified according to project maturity levels and the associated actions (i.e., business decisions) required to move a project toward commercial production. For Contingent Resources the sub-classifications are:

- Development Pending
- Development On Hold
- Development Unclarified
- Development Not Viable

PRMS also states that projects currently classified as Contingent Resources may be broadly divided into two groups:

- Economically Viable Contingent Resources are those quantities associated with technically feasible projects where cash flows are positive under reasonably forecasted conditions but are not Reserves because they do not meet the commercial criteria.
- Economically Not Viable Contingent Resources are those quantities for which development projects are not expected to yield positive cash flows under reasonable forecast conditions.

3.1.2 *Prospective Resources*

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorised in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

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3 Petroleum Resource Management System (“PRMS”), 2018. Sponsored by SPE/AAPG/WPC/SPEE/ SEG/SPWLA/EAGE

3.2 *Uncertainty Estimation*

The estimation of in-place hydrocarbon volumes is an integral part of the evaluation process. It is normal practice to assign a range to the volume estimates because of the uncertainty over exactly how large the field or discovery will be.

The range of uncertainty is represented by a probability distribution, a low, best, and high estimate shall be provided such that there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the low estimate; at least a 50% probability (P50) that the quantities actually recovered will equal or exceed the best estimate; and at least a 10% probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

The approach to describing uncertainty may be applied to Reserves, Contingent Resources, and Prospective Resources (Figure 3-1). When applied to Reserves these confidence levels equate to the Proved (1P), Proved plus Probable (2P) and Proved plus Probable plus Possible (3P) cases respectively. When applied to Contingent Resources these confidence levels equate to the 1C, 2C and 3C cases, respectively and when applied to Prospective Resources they equate to 1U, 2U and 3U.

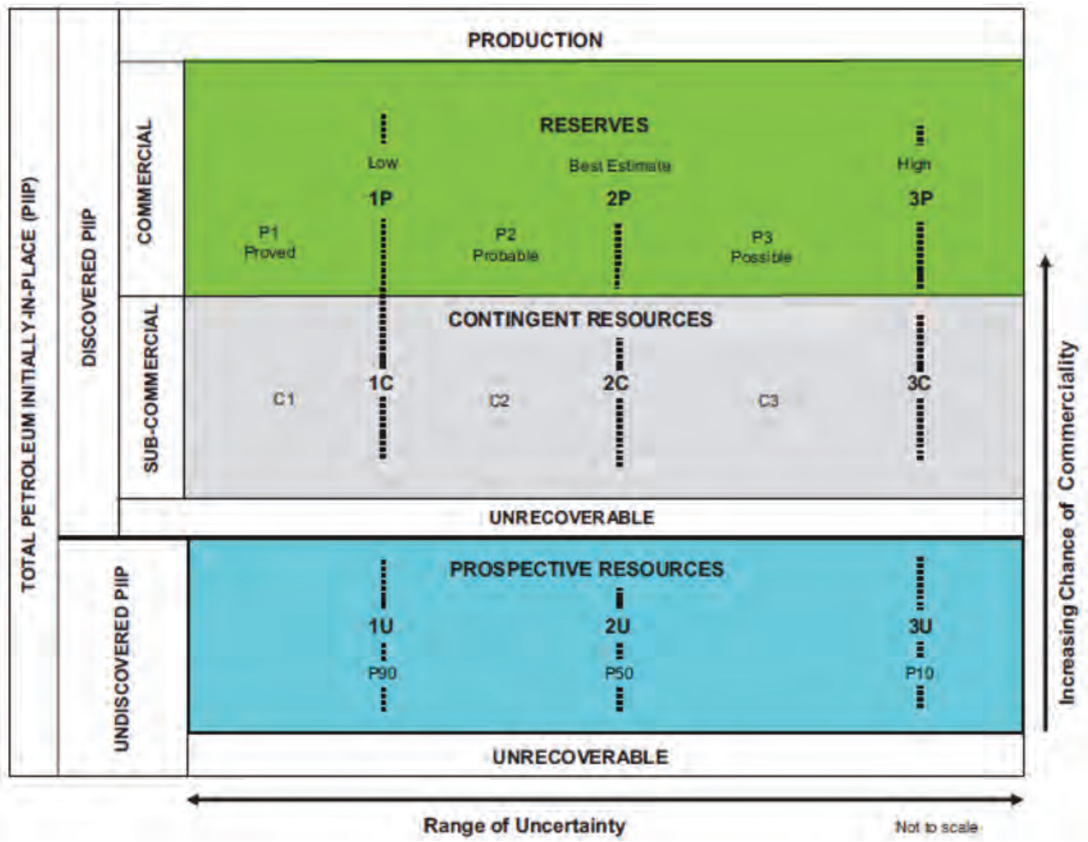

Figure 3-1: PRMS Resource Classification Framework

The estimation of expected hydrocarbon resource is an integral part of the evaluation process. It is normal practice to assign a range to the volume estimates because of the uncertainty over exactly how large the discovery or prospect will be. Estimating the range is normally undertaken probabilistically (using Monte Carlo simulation), using a range for each input parameter to derive a range for the output volumes. Key contributing factors to the overall uncertainty are data uncertainty, interpretation uncertainty and model uncertainty. Volumetric input parameters, gross rock volume (GRV), porosity, net-to-gross ratio (N:G), water saturation (Sw), fluid expansion factor (Bo or Bg) and recovery factor, are considered separately. RPS has internal guidelines on the best practice in characterising appropriate input distributions for these parameters. Systematic bias in volumetric assessment is a well-established phenomenon. There is a tendency to estimate parameters to a greater degree of precision than is warranted[4] and to bias pre-drill estimates to the high side[5]. Rose and Edwards observe the tendency towards assessing volumes in too narrow a range with overly large low-side and mean estimates. RPS uses benchmarked P90/P10 ratios and known field size distributions to check the reasonableness of estimated volumes.

3.3 *PRMS Definitions of Chance*

As a project moves to a higher level of commercial maturity in the classification (see Figure 1.1 vertical axis), there will be an increasing chance that the accumulation will be commercially developed and the project quantities move to Reserves. For Contingent and Prospective Resources, this is further expressed as a chance of commerciality (Pc), which incorporates the following underlying chance component(s):

- The chance that the potential accumulation will result in the discovery of a significant quantity of petroleum, which is called the "chance of geological discovery," (Pg).
- Once discovered, the chance that the known accumulation will be commercially developed is called the "chance of development," (Pd).

There must be a high degree of certainty in the chance of commerciality, Pc, for Reserves to be assigned; for Contingent Resources, Pc = Pd; and for Prospective Resources, Pc is the product of Pg and Pd.

3.3.1 *Chance of Geological Discovery*

When dealing with undrilled prospects there is an accepted industry approach to risk assessment for Prospective Resources. It is standard practice to assign Pg depending on the likelihood of source rock, charge, reservoir, trap and seal combining to result in a present-day hydrocarbon accumulation. RPS assesses risk by considering both a Play Risk and a Prospect Risk. The chance of success for the Play and Prospect are multiplied together to give Pg. RPS considers three factors when assessing Play Risk: source, reservoir, seal and considers four factors when assessing Prospect Risk: trap, seal, reservoir and charge. The result is the chance or probability of discovering hydrocarbon volumes within the range defined. It is not an estimation of commercial chance of success.

3.3.2 *Chance of Development*

When assessing the chance of a Contingent Resource reaching commercial status and hence being classified as a Reserve the auditor has to estimate the chance that the following will be forthcoming:

- Evidence of a technically mature, feasible development plan.
- Evidence of financial appropriations either being in place or having a high likelihood of being secured to implement the project.
- Evidence to support a reasonable time-frame for development.
- A reasonable assessment that the development projects will have positive economics and meet defined investment and operating criteria. This assessment is performed on the estimated entitlement forecast quantities and associated cash flow on which the investment decision is made.
- A reasonable expectation that there will be a market for forecast sales quantities of the production required to justify development. There should also be similar confidence that all produced streams (e.g., oil, gas, water, CO2) can be sold, stored, re-injected, or otherwise appropriately disposed.
- Evidence that the necessary production and transportation facilities are available or can be made available.

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4 Rose, P.R., 1987. Dealing with Risk and Uncertainty in Exploration: How Can We Improve? AAPG Bulletin, 71 (1), pp. 1-16.

5 Rose, R.P. and Edwards, B., 2001. Could this prospect turn out to be a mediocre little one-well field? Abstract, AAPG Bulletin, 84(13)

- Evidence that legal, contractual, environmental, regulatory, and government approvals are in place or will be forthcoming, together with resolving any social and economic concerns.

4 REGIONAL GEOLOGY

4.1 *Structural Evolution*

Figure 4-1 shows the main structural elements in Eastern Tanzania. The Ruvuma PSA is located within the Ruvuma Basin.

During the Carboniferous to the Permian, extended rift structures over Gondwana linked to create a broad platform depression that filled with thick sequences of terrigenous and carbonate formations known as the Karoo Group. This was the first phase of basin development in Eastern Tanzania, forming a series of coastal basins along the East African coast over high grade metamorphic basement mainly gneisses of the Mozambique orogenic belt. North to northeast trending rifts formed and were subsequently re-used during the early Jurassic extension that ultimately led to the separation of Madagascar from East Africa. Where rift faults are well imaged in the Mandawa Basin and the Dar Es Salaam platform a strong northeast trend is evident, parallel to the ultimate axis of separation.

A secondary north-northwest trend may represent a Jurassic strike-slip trend but is also the later Cretaceous fault orientation. The end of Jurassic rifting is recorded in the stratigraphy by an unconformity within the Aalenian. In the Late Jurassic salt movement dominated structural development in the Mandawa basin, but as with the older Jurassic this sequence is not consistently imaged on seismic data elsewhere.

The development of a major coarse clastic system in the Neocomian was likely to have been caused by uplift of the interior of Africa, but there is no tectonism evident in the coastal basins at this time. North trending extensional faults developed in the later part of the early Cretaceous as extension in the Indian Ocean started, and continued into the late Cretaceous. As the coastal basins became part of the passive margin of the Indian Ocean during the late Cretaceous and Tertiary, subsidence of the margin formed a regional east dipping palaeo-slope, and the presence of plastic shales in the basal Upper Cretaceous and Tertiary allowed listric fault systems to develop. In the south of the region the thick Tertiary sequence of the Ruvuma Basin produced by the delta of the Ruvuma river has major listric faults developed at several levels.

There appear to be periods of major regional uplift of the region related to the development of the East African Rift System to the west. These were early in the Eocene and early in the Miocene, and almost certainly stopped the generation of hydrocarbons in the onshore basins. Local uplifts produced large anticlinal structures, the culmination of one of which is Mafia Island. The mechanism for production of these uplifts is not clear. Regional compression, possibly by “ridge push” is likely to have caused these regional uplifts and smaller inversion features observed in many areas.

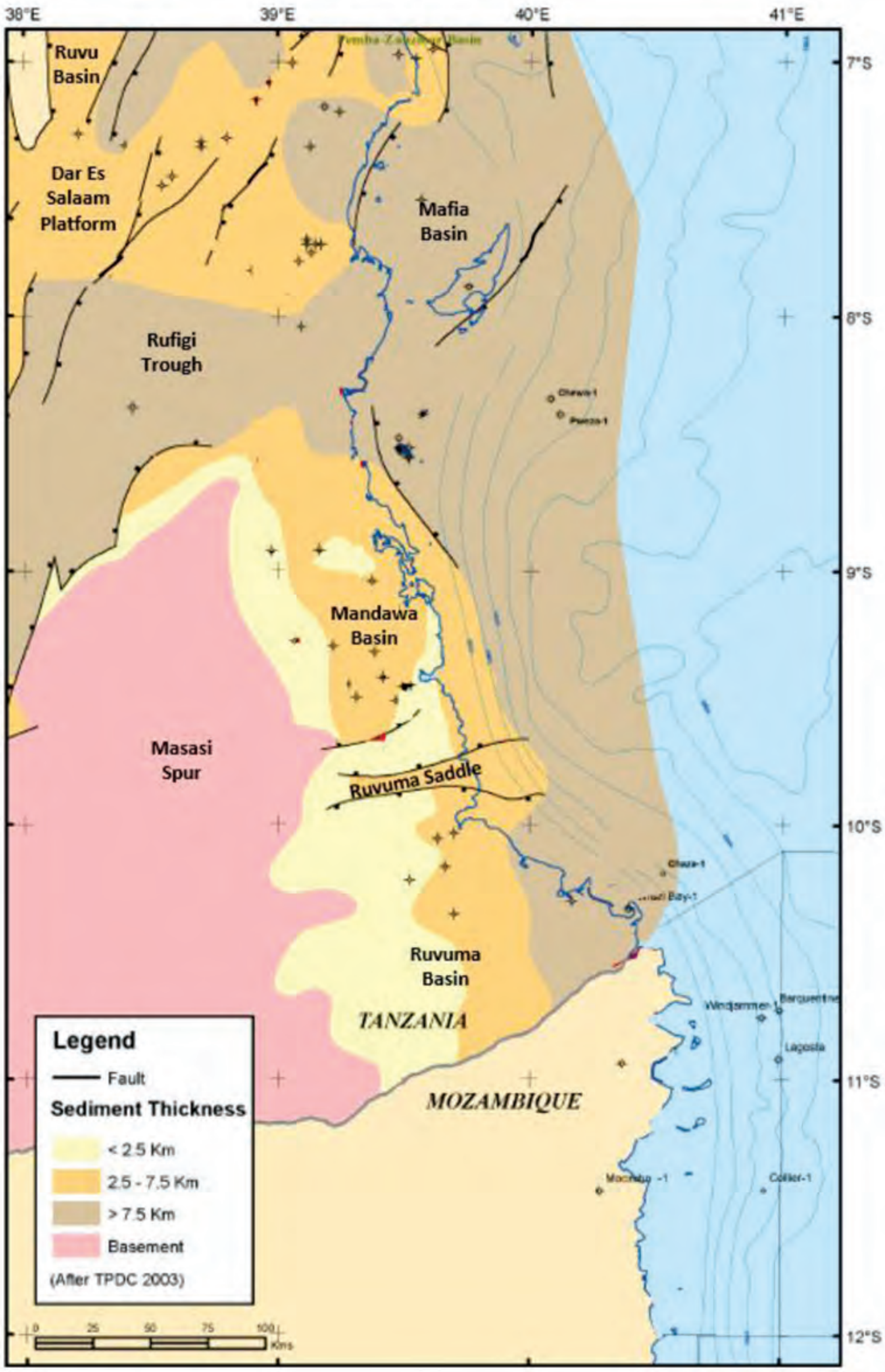


Figure 4-1: Structural Elements of Eastern Tanzania

4.2 *Stratigraphy*

The rift phase began in the late Carboniferous and continued throughout the Permo-Triassic into the early Jurassic. Stratigraphic units are known from the interior Selous and associated basins and the Mandawa basin of eastern Tanzania. In the Mandawa Basin, basement is overlain by Pliensbachian to Lower Aalenian rift sequence clastics and evaporites. Overlying and possibly laterally equivalent to the upper part are shallow marine sandstones, carbonates and shales. Thick limestones of Aalenian age are present in the west. To the northwest, in the Rufiji Trough and on the Dar Es Salaam Platform, the Jurassic clastic rift sequence contains fewer shales and there are no evaporites.

The Early Jurassic transition stage encompassed the last pulses of major rifting and is associated with differential subsidence leading to the formation of a series of semi-enclosed basins around the flanks of the Masasi Basement Spur and the Dar Es Salaam Platform. A widespread transgression resulted in the development of restricted marine conditions in the subsiding basins leading to the possible extensive deposition of evaporates, the Nondwa Formation found in the Mandawa basin. On the flanks of the basins, continental conditions persisted with Early Jurassic sediments (Ngerengere Beds) demonstrating similar lithofacies to the underlying megacycles of the older Karoo, particularly the widespread distribution of fluvial sandstones.

The post-rift phase, the active break-up of Gondwana, started in the Middle Jurassic with a regional unconformity, and the onset of sea floor spreading (Bajocian), further advancing the marine transgression which resulted in the deposition of thick shales in the west. In the Mandawa Basin shallow marine sandstones and shales are present, capped by the Bajocian to Bathonian Mtumbei limestone. During Kimmeridgiana and Titonian times, the Tethyan transgression extended widely, resulting in discordant deposition of Late Jurassic marine shale and limestone. A significant sequence boundary or disconformity separates the Mtumbei Limestone from the shales and shallow marine sandstones of the Mtumbei Formation. The oldest rocks drilled offshore are Callovian to Oxfordian shales with minor, apparently deep-water sandstones.

Regression in the Early Cretaceous resulted in the accumulation of thick continental, deltaic and marginal marine deposits. At the end of the Early Cretaceous, Madagascar had virtually stopped drifting with respect to Africa, and, by that time, formation of the main structures of the East Africa continental margin had been completed. A regional mid-Cretaceous unconformity is overlain by a shelf/slope setting with turbidite sands and slope shales. The deposition of platform carbonates marks the end of the regressive phase and the onset of a major marine transgression in the Late Cretaceous. Local regressive sedimentation persists in the Cenomanian but generally the Late Cretaceous comprises shelf and slope claystones.

In response to the early uplift and doming that preceded rifting of the modern-day East African Rift System, the Rufiji and Ruvuma River delta systems began to form during the Oligocene. The passive margin sequence was thus succeeded by Mid-Tertiary to Recent deltaic progradation to produce a thick, eastward prograding wedge of rapidly deposited clastic sediments containing sandstones at a number of levels. The position of the Ruvuma Delta depo-centre was constrained by fault block rotation and basin subsidence during the Tertiary, with the early centre located towards the northern part of the Ruvuma Basin. These sediments have been subjected to intensive gravity-driven deformation, shale diapirism and slumping eastward prograding wedge of rapidly deposited clastic sediments containing sandstones at a number of levels.

Figure 4-2 shows a stratigraphic column for the Tanzania Coastal Basins.

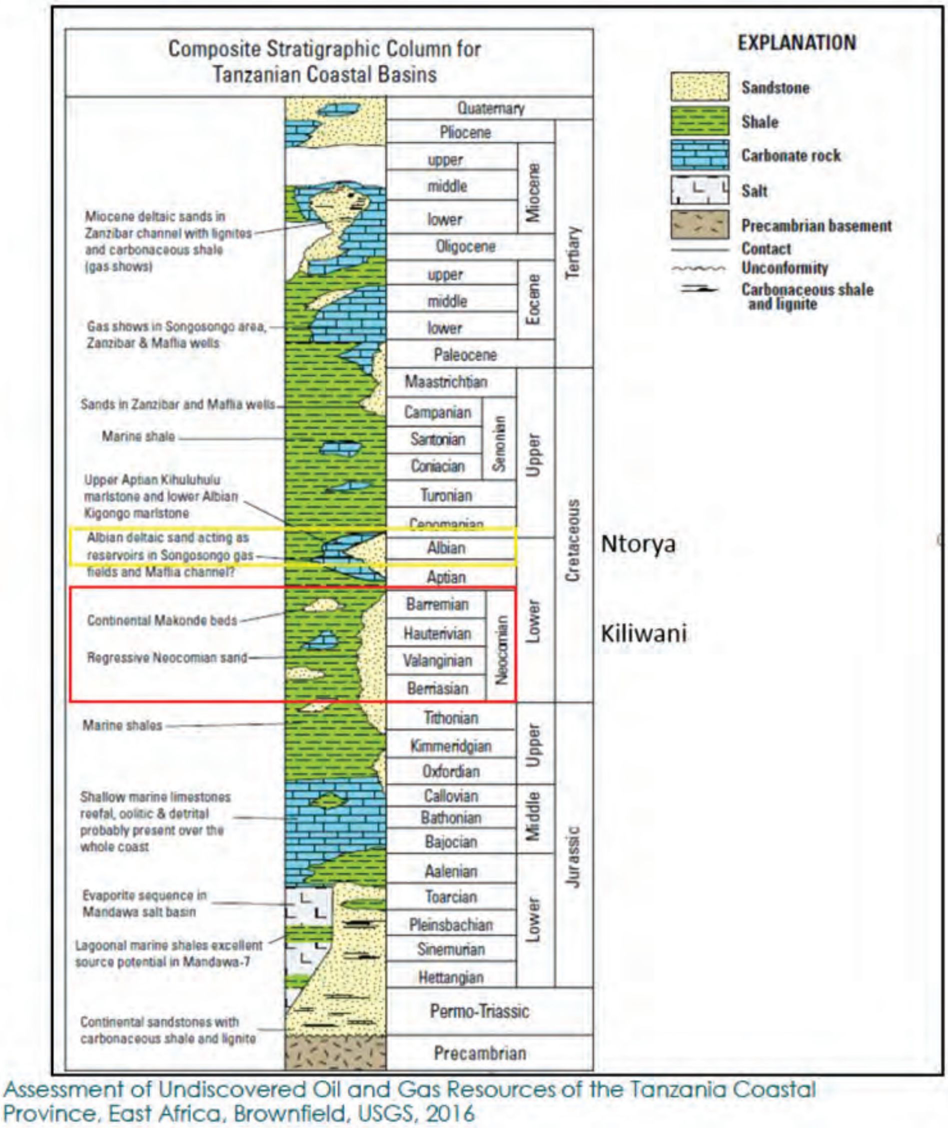


Figure 4-2: Stratigraphic Column for the Tanzania Coastal Basin, Ntorya and Kiliwani Reservoirs Highlighted

4.3 *Source Rock*

A proven world class Jurassic source rock exists on the margins of East Africa. Jurassic (and Permian) source rocks are believed to be responsible for the major offshore gas discoveries. There are also live oil seeps and oil shows that may be assigned to the Jurassic source rock.[6]

The main source rocks in the Ruvuma basin consist of Permian lacustrine shales, Early Jurassic shales and Late Cretaceous marine shales. The oldest known sediments in the Ruvuma PSA area are of the Permian Karoo Formation with locally developed source rocks. In the Lukuledi-1 well, coals and coaly shales were encountered. The Early to Middle Jurassic section contains restricted marine Type II kerogen source rock and marginal marine, deltaic Types II and III kerogen source rocks, and Type I lacustrine source rock. The Early to Middle Jurassic lacustrine Type I and restricted marine Type II source rocks contain as much as 8.7 weight percent TOC. The Permian to Jurassic section is likely to be mature over most of the licence areas. At the time of deposition, an enclosed basin existed in the narrow strait between Africa and the continental masses of Madagascar and India. These organic-rich sediments were deposited and preserved under anoxic conditions. Maturation, which led to gas/condensate generation, occurred in the Late Cretaceous to Early Tertiary. The Karoo shales are organic rich and generally sand poor. The Lukuledi-1 well encountered rich gas prone source rock

6 Basin Modelling on Ruvuma License; SPIE, September 2014

within the Permian and lower Jurassic sections but was immature; modelling indicates it will be gas mature immediately off structure[5]. Deep-seated faults may act as migration conduits from Karoo units into the shallower Cretaceous and Early Tertiary reservoir intervals.

The primary hydrocarbon phase in the Ruvuma areas is anticipated to be gas although oil shows were encountered in the Likonde-1 well and minor condensate was encountered from the Ntorya-1 well test. In Ntorya-2, black oil was encountered across the shakers at the top of the reservoir section.

5 NTORYA DISCOVERY

Ntorya is a gas discovery stratigraphically trapped in Albian-age channel sandstones. The resource assessment for the Ntorya discovery have been split into two cases (Case A and Case B) based on the current development plans. There is a firm plan to develop the field with the two existing wells plus a third new well called Chikumbi-1. The primary target of Chikumbi-1 is a deeper Jurassic prospect but the well will appraise the Ntorya gas discovery and will be used as a producer.

Depending on the performance of this initial development a second project consisting of up to eight additional wells may be considered.

Case A relates to volumes that it is considered could be accessed and recovered using the initial three well development scenario. Case B relates to volumes that it is considered could be accessed and recovered by an extended development of up to a total of 11 wells.

Resources in Case A are classified, in accordance with PRMS, as Contingent Resources "Development Pending". Resources in Case B are classified as Contingent Resources "Development Unclarified",

5.1 *Database*

RPS has been provided with a Kingdom project containing a sparse irregular grid of 2D seismic data of varying line vintage. The Ntorya discovery has sparse coverage of 1988-2007 vintage seismic data, with additional infill of 2014 vintage data (Figure 5-1). The seismic data is generally of poor to moderate quality, although some improvements were gained due to improved modelling of the weathered layer. Line spacing is in the order of 2.0 - 7.5 km, with NE-SW orientated lines typically closer spaced than those orientated NW-SE.

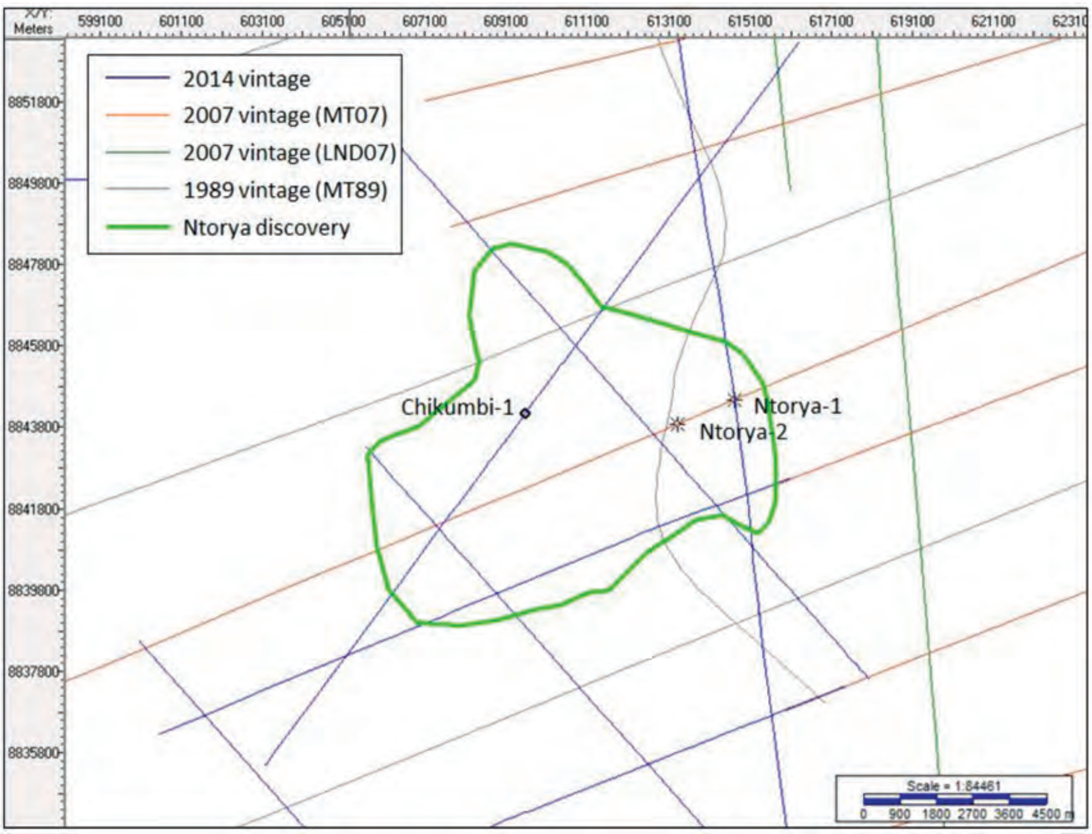


Figure 5-1: Location of 2D seismic data over Ntorya discovery

The Kingdom project included the Ntorya-1, Ntorya-2 and Likonde-1 wells, complete with deviation data, formation tops and wireline logs. Structural grids and horizons were made available in the project, as were amplitude extractions and isochores for the key intervals.

The following well data were provided for Ntorya-1 and Ntorya-2 outside of the Kingdom project:

- Raw and interpreted wireline logs
- Composite log
- Mud log
- End of well reports
- Checkshot data
- Various reports including mapping updates, geophysics interpretations, third party evaluation of the Ruvuma PSA and 2015 CPR by Senergy.

No core or MDT data were acquired for either of the Ntorya wells. Additional data was provided for the offset well, Likonde-1.

5.2 *Geophysical and Geological Interpretations*

The reservoir for the Ntorya discovery is interpreted to be Albian age sandstones deposited as part of a NE flowing confined channel complex. The trapping mechanism is interpreted to be a stratigraphic pinchout updip into the canyon, with lateral pinchouts to the NW and SE confined within the canyon system. The downdip extent of the discovery is mostly controlled by a likely gas-down-to, but is also partly facies controlled as fan facies are expected to be present further downdip of the Ntorya wells.

5.2.1 *Well Evaluation*

The Ntorya-1 well was drilled in 2012 and discovered gas-bearing sandstones at a depth of 2,662m MD. The well discovered a 5m sand and a 16m sand, separated by a 3.5m shale (Figure 5-2). The wireline logs show the upper (5m) sand to be gas bearing, which was confirmed by a successful test over the interval that flowed at a maximum rate of 20 MMscf/d with 139 barrels of associated condensate. The lower (16m) sand was not included in the test. The wireline logs for this interval are less definitive than for the sand above, but petrophysical work by both RPS and the operator conclude that the lower sand is also gas bearing, giving a gas down to of 2,510m TVDSS. In good hole sections, RPS considers the observed separation between TCMR and DMRP curves to be a good indicator of gas in both the upper and lower sands. Senergy interpreted the lower sand as water bearing in their 2015 CPR. The upper sand is of better reservoir quality with an average porosity of 19% and water saturation of 17%, whereas the lower sand has a porosity of 14% and a water saturation of 34%.

The Ntorya-2 well reached TD in February 2017 and discovered a 51m gross interval of gas-bearing sandstones at a depth of 2,593m MD (Figure 5-2). Wireline logs indicate the entire sandstone interval is gas-bearing, which is confirmed by a test that flowed at 17 MMscf/d. The reservoir penetration in Ntorya-2 is structurally higher than Ntorya-1, so the GDT in Ntorya-1 remains the deepest observed hydrocarbons in the discovery. The Ntorya-2 well encountered a single gross sandstone interval with an average porosity of 16% and water saturation of 29%.

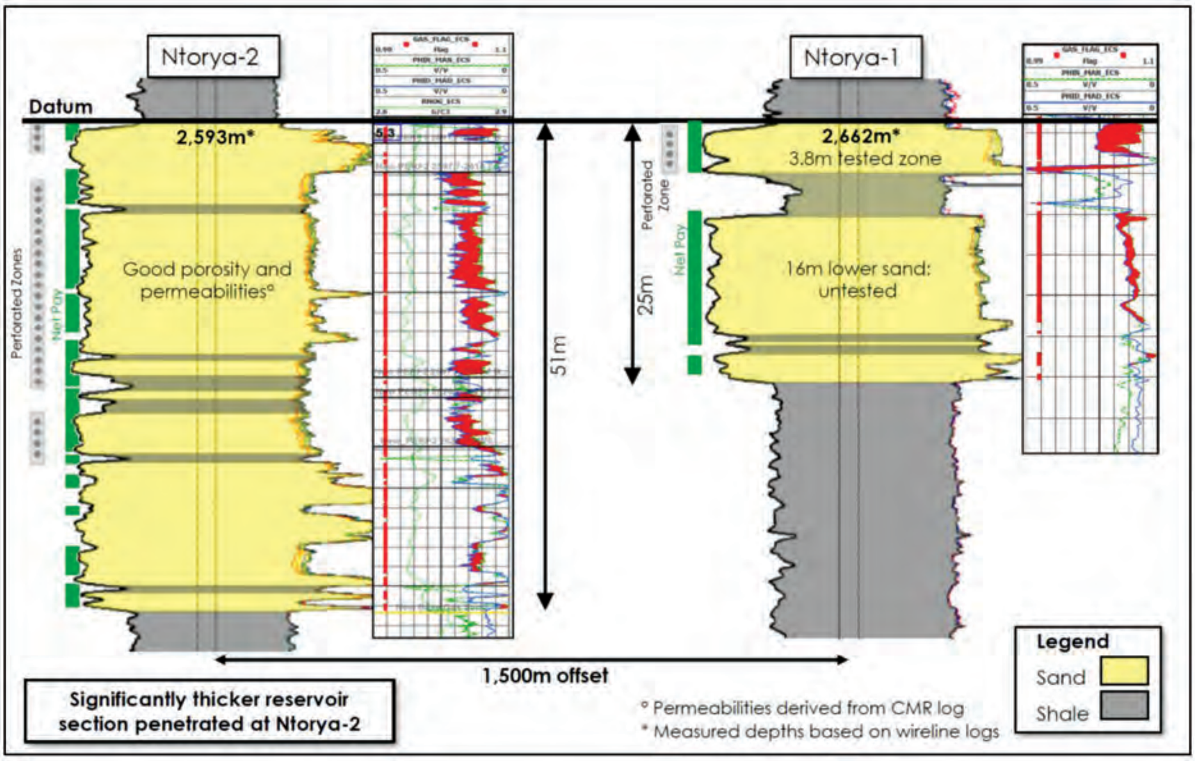


Figure 5-2: Reservoir Section of Ntorya-1 and Ntorya-2 Wells

RPS performed independent petrophysical interpretation of Ntorya-1 and 2; CPI plots are shown in Figure 5-3 and Figure 5-4. As no formation water analysis data was available, formation water resistivity used for the study was based on Pickett plots and compared with CMR data. The Sw calculated for these wells are uncertain, due to uncertainty around water salinity, cementation factor etc. Log data is not conclusive for identifying contacts for Ntorya-1 and no MDT/RFT data were obtained in the wells. The well test produced from perforations above in the upper sand package of NT-1 and no water was produced. Ndovu state that there was no cement behind casing over the reservoir section and water would have been anticipated to be produced from below 2,665m if the section from 2,666m to 2,689m was water bearing. Therefore, RPS support the interpretation of the deeper GDT based on CMR logs and the lack of water production.

Porosity cut-off of 8% and VCL of 0.5 have been used to define net sand. In the absence of core data for Ntorya, analogue data from the core analysis of Lukuledi-1 has been used to define the 8% cut-off, corresponding to a 0.1 mD permeability.

A Sw cut-off of 50% has been applied for derivation of net pay. This is consistent with the Sw cut-off used in previous petrophysical reports provided by Ndovu. Zone thicknesses are summarised in Table 5-1. Petrophysical averages are shown in Table 5-2.

6 Basin Modelling on Ruvuma License; SPIE, September 2014

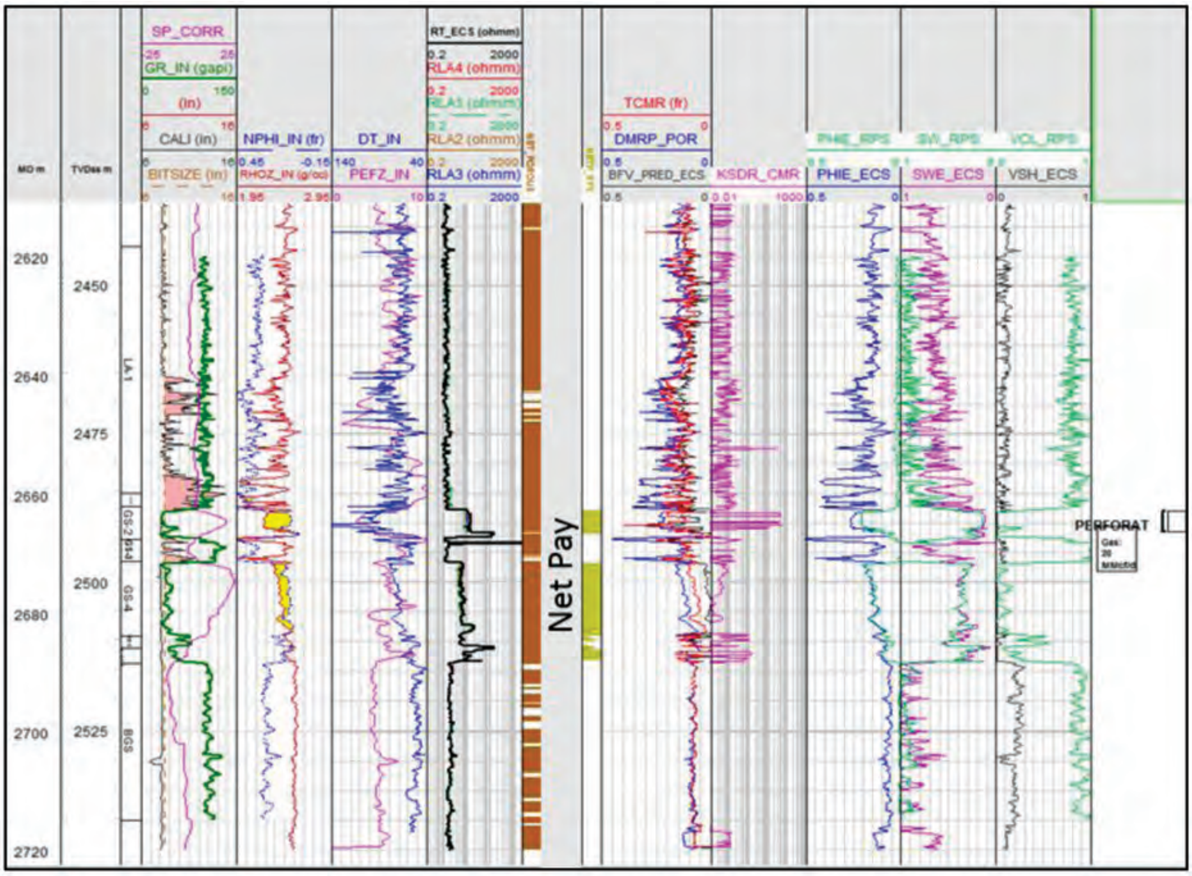


Figure 5-3: CPI Plot for Ntorya-1 with Net Pay Highlighted in Yellow/green

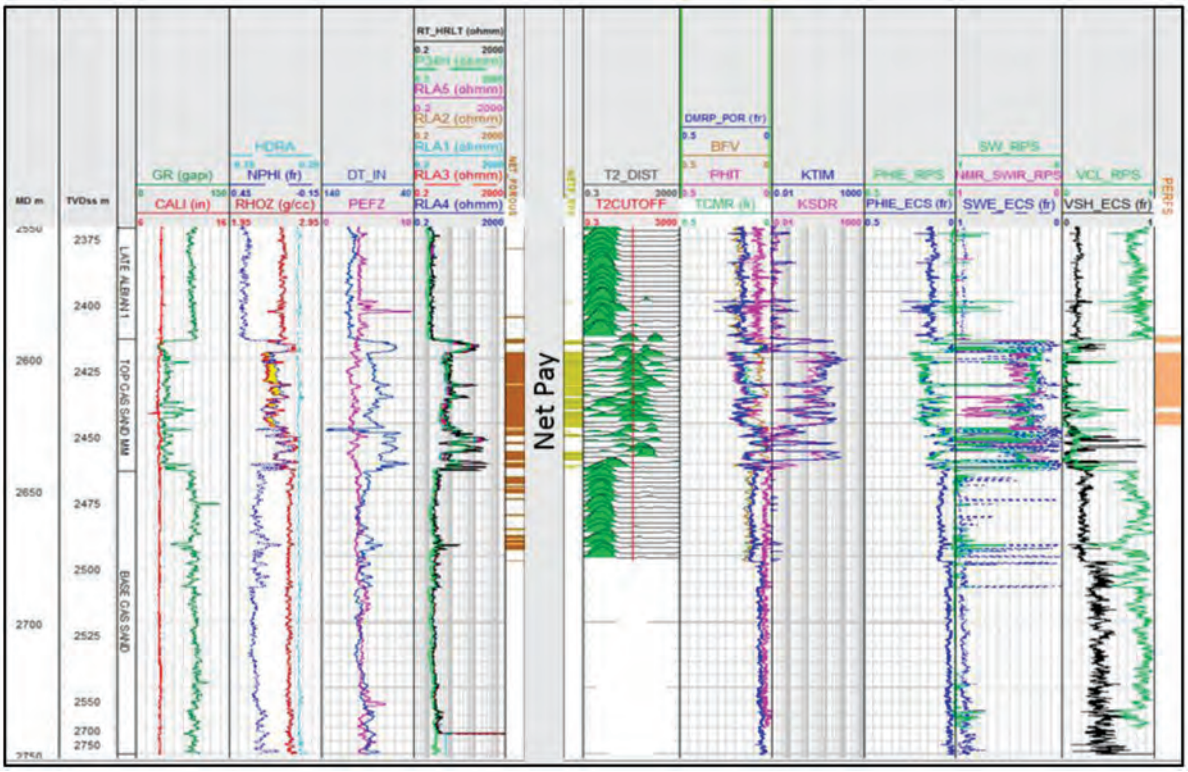


Figure 5-4: CPI Plot for Ntorya-2 with Net Pay Highlighted in Yellow/green

Zone	TOP MD (m)	Base MD (m)	Top TVDSS (m)	Base TVDSS (m)	Gross TVD (m)	Net TVD (m)	NTG (%)	Pay TVD (m)
Ntorya-1	2,662.1	2,688.7	2,487.8	2,514.3	26.5	17.1	65	17.1
Ntorya-2	2,592.7	2,642.8	2,413.8	2,463.9	50.1	30.0	60	29.1

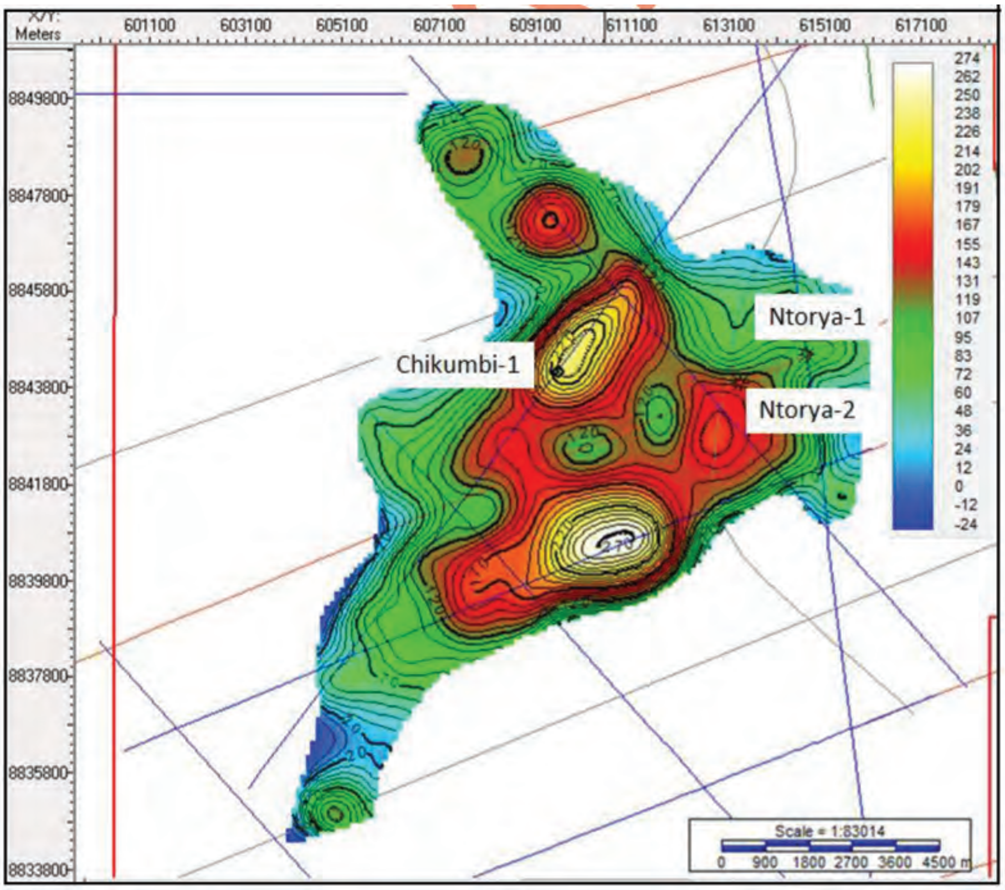
Table 5-1: Ntorya-1 and 2 Petrophysical Reservoir Analysis

Zone	Phie net	Sw net	Phie pay	Sw pay
	(%)	(%)	(%)	(%)
Ntorya-1	15	30	15	30
Ntorya-2	16	31	16	29

Table 5-2: Petrophysical Averages for Ntorya-1 and 2

5.2.2 *Seismic Interpretation and Mapping*

Ndovu has mapped the top of the reservoir on a peak on the seismic data which is confirmed by a synthetic seismogram generated by Schlumberger for Ntorya-1. The base of the sandstone is typically represented by a trough on the seismic, although the reservoir is generally near, or below, the tuning thickness. This means the thickness of the gross sandstone interval cannot reliably be mapped from seismic. Ndovu has also mapped the Intra-Albian Unconformity, which was used to define the gross Albian reservoir fairway thickness (Figure 5-5), but is greater than the sand thickness observed in the wells. Figure 5-6 shows a key seismic line through the Ntorya wells, showing the seismic picks and trap geometry.



Source: Ndovu

Figure 5-5: Ndovu Reservoir Fairway Isopach (source Ndovu)

The top reservoir pick jumps at various locations, which RPS interprets to be the transition between different channel bodies within the complex, although poor data quality means there is some uncertainty associated with this interpretation. RPS considers all the discrete channel bodies within Ntorya to be connected (in a geological timeframe) and therefore considered part of a single discovered volume. The ability of individual wells to efficiently drain multiple channel bodies remains uncertain. Figure 5-6 shows the potential downdip extension of the discovery into a deeper sand body that is unpenetrated by wells. This down dip sand body carries a large uncertainty regarding facies and fluid fill.

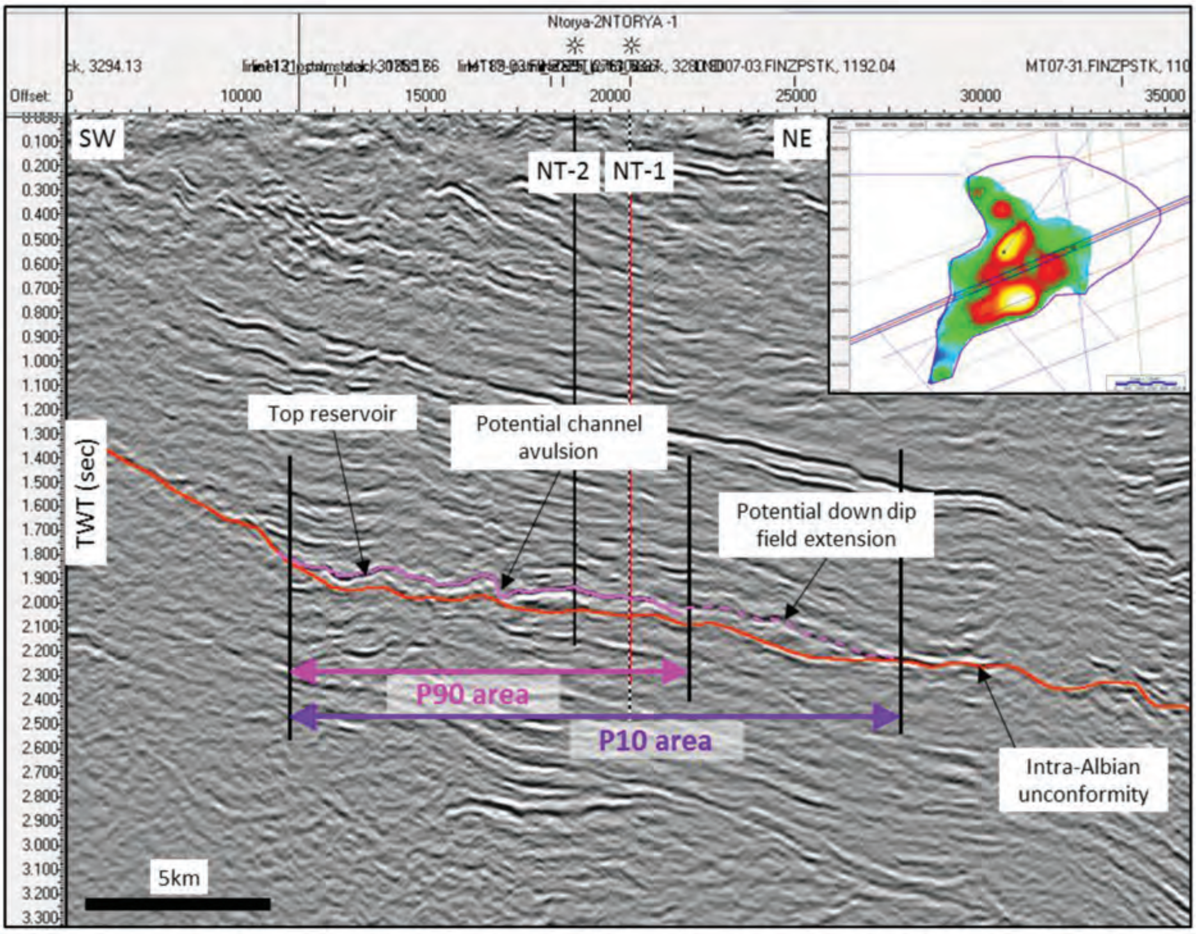


Figure 5-6: Key Seismic Section through Ntorya Wells

5.3 *Engineering and Production Data*

Separator samples were obtained from the Ntorya-1 and Ntorya-2 wells (NT-1 and NT-2) and PVT tests for both were performed. The gas composition analysis for the recombined samples shown in the next two graphs reveals that the two wells share the same fluid (Figure 5-7 and Figure 5-8). Notice that both graphs show the same data but for Figure 5-7, the x axis is in log scale to show the heavier components and the second one is in normal scale to show the lighter, much more abundant methane and ethane.

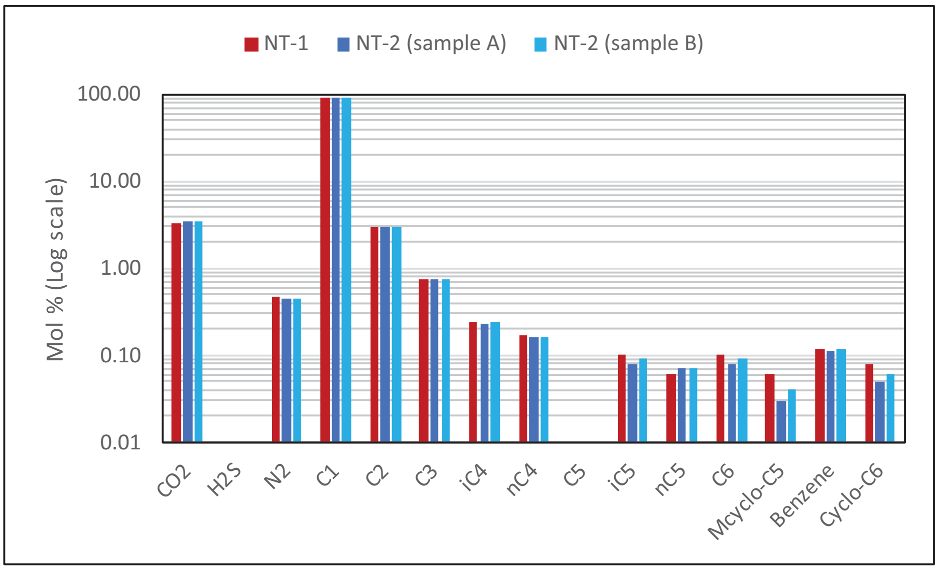


Figure 5-7: Ntorya Gas Composition (Log scale)

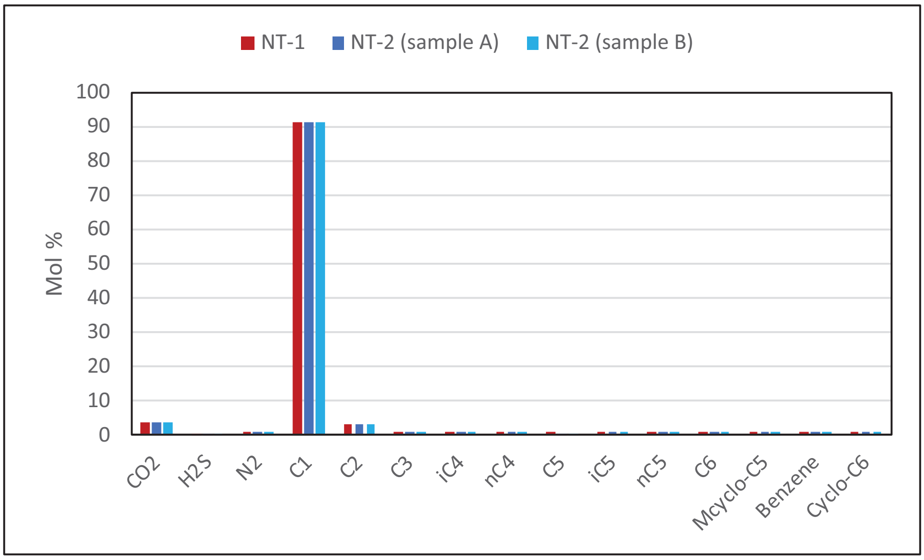


Figure 5-8: Ntorya Gas Composition (Normal Cartesian Scale)

Constant composition expansion tests were performed for samples from both wells. Based on these data, RPS calculated a range of Gas Formation Volume Factors (Bg) i.e. 0.0045-0.0042-0.0039 rcf/scf for the low, base and high cases respectively.

A drill stem test was performed on Ntorya-1 and a production test was performed on Ntorya-2. The interval test performed for both wells revealed a low reservoir deliverability with absolute open flow rates of around 20 MMscf/d. The maximum stable rates achieved in the tests were approximately 10 MMscf/d and between 15-17 MMscf/d for the Ntorya-1 and Ntorya-2 wells respectively.

The test interpretation for Ntorya-1 showed a certain level of crossflow between layers. Different models successfully matched the data. Four out of five models assumed bounded depleted layers of limited dimension and one with extent size not delimited by the test.

In case of Ntorya-2 the multiple interpretations that match the data also suggest multi-layer situations and include barriers with different geometries.

In summary, the well tests inform about the heterogeneity of the reservoir, with barriers and baffles produced by lower permeability layers intercalated with high permeability, plus the existence of faults, is expected. The well tests' radius of investigation also proved a minimum connected volume to the wells of, at least, one Bscf. The minimum connected volumes are treated in this case as the P99 in anchoring the range for GIIP calculations because the well tests did not identify closed boundaries within the limited duration of the well tests.

In addition, a PLT was run for the Ntorya-2 well which revealed 78% of the flow was coming from two metres on the upper part of the perforations (2,593 to 2,595 m MD) (Figure 5-9). The Operator attributes this to the ineffectiveness of the clean-up of the well, which prevented the whole interval from producing. The Operator expects a higher deliverability during development. However, RPS is only considering the deliverability demonstrated in the existing tests for this Report.

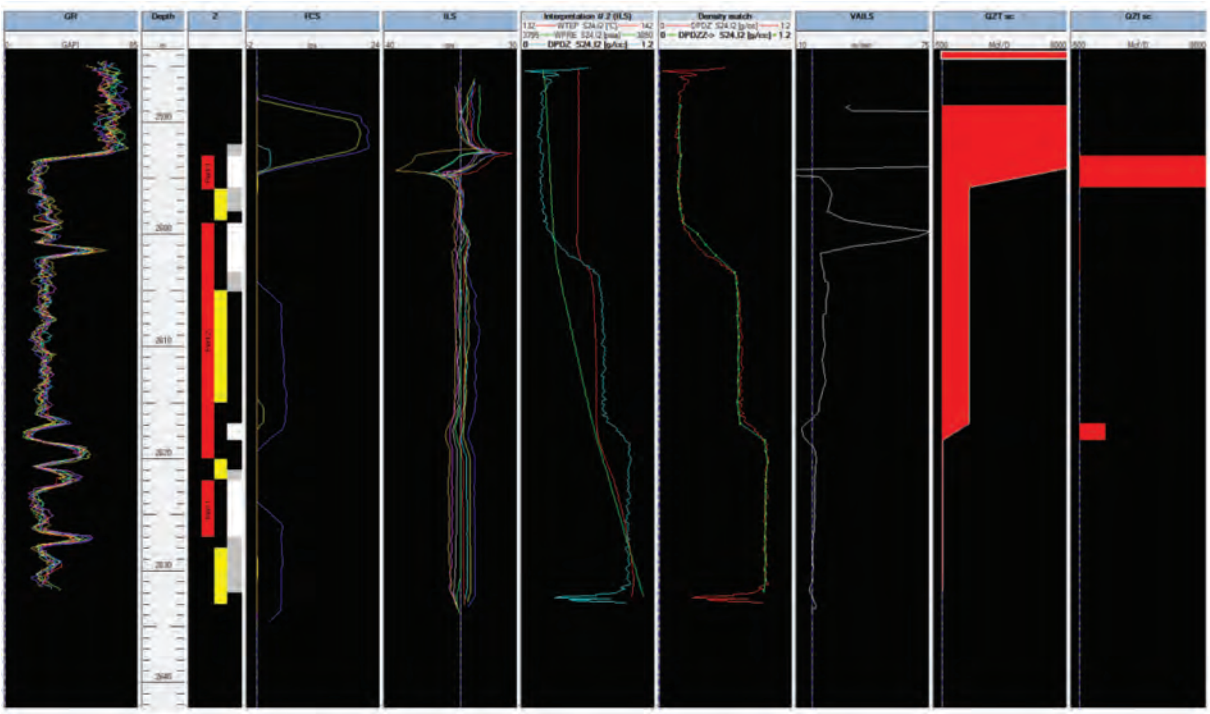


Figure 5-9: PLT Performed on 24/64'' Choke for Ntorya-2 Well

5.4 *In-Place Volumes*

The contingent resources, and respective in-place volumes, for the Ntorya discovery have been split into two cases (Case A and Case B) based on the current notional development plans (see Section 5.5). There is a firm plan to develop the field with the two existing wells plus a third new well (Chikumbi-1). Depending on the performance of this development a second project consisting of up to eight additional wells may be considered.

In the subsequent discussion, Case A relates to volumes that it is considered could be accessed and recovered using the current three well development scenario. Case B relates to volumes that it is considered could be accessed and recovered by an extended development of up to a total of 11 wells.

Case A gas-in-place volumes have been calculated using Monte Carlo techniques in the Reserves Evaluation Program (REP) made by Logicom. The gross rock volume (GRV) was defined by specifying area, thickness and shape factor ranges for the reservoir. This removes some uncertainties associated with the mapping of the top and base of the reservoir and depth conversion. As the top and base of the reservoir are not fully resolvable on seismic across the entire discovery, it was deemed more suitable to use thicknesses derived from well penetrations, with seismic isochores providing a soft input. The input parameter ranges for Case A are given in Table 5-3. The ranges are relatively tight compared to those for Case B as Case A only considers a limited area around the existing well control and the planned Chikumbi-1 well. The input parameter ranges are based around the observations from the Ntorya-1 and Ntorya-2 wells. The area range has been defined using P99 and P10 inputs. The P99 area has been calculated by taking the drainage area from Ndovu's Ntorya-2 well test interpretation and applying it to each of the three development wells, Ntorya-1, Ntorya-2 and Chikumbi-1 (Figure 5-10). The P10 area considers a more geological boundary for each well, extending the boundary to interpreted sand body limits identified on seismic.

Volumetric

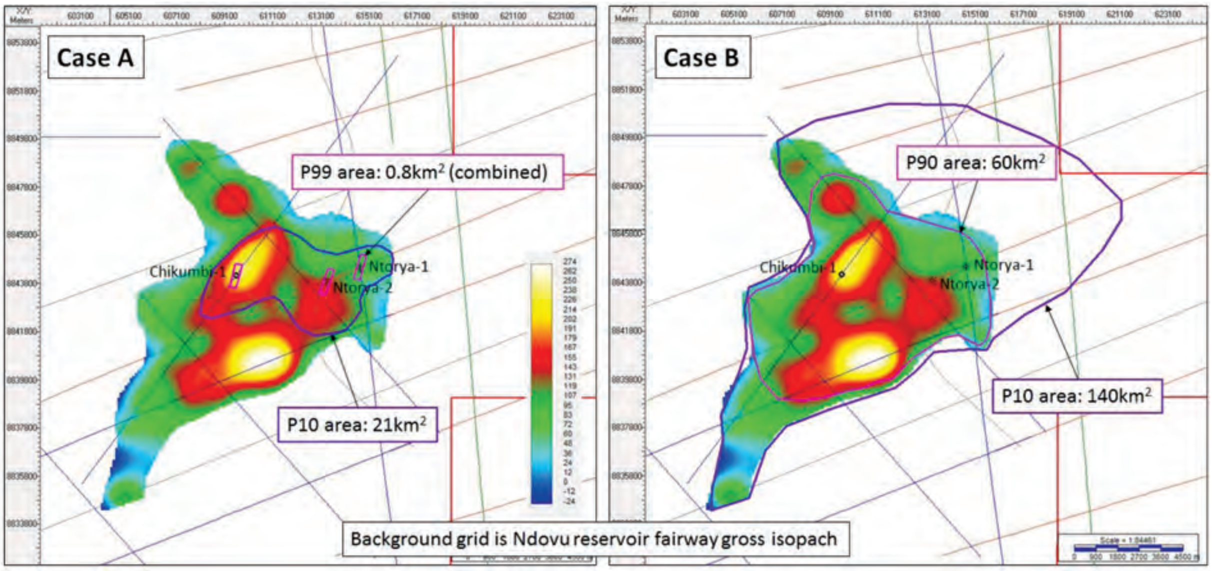


Figure 5-10: Input Areas for Ntorya Case A & Case B Volumetric Calculations

			P90	P50	P10
Area	sq. km	Lognormal	2.1	6.7	21
Thickness	m	Normal	30	40	50
Shape factor	fr	Triangular	0.93 (min)	0.96 (mode)	0.99 (max)
Degree of fill	%	Single	–	100	–
Net to Gross	%	Normal	50	60	70
Porosity	%	Normal	14	15.5	17
Water Saturation	%	Normal	25	30	35
FVF	scf/rcf	Normal	222	238	254

Table 5-3: Input Parameters for Ntorya Case A

Case B gas-in-place volumes have been calculated using the same methodology as for Case A. Volumes were calculated for Case A and Case B together, using input parameter ranges given in Table 5-4. The ranges for the input parameters are wider to account for the increase in uncertainty away from well control. The area range was defined using P90 and P10 inputs. The P90 area (Figure 5-10) represents the conservative extent of the sands based on high confidence mapped pinch-outs on seismic (Figure 5-6). The P90 area does not extend far downdip beyond the Ntorya-1 penetration as the low-case assumes a GWC at, or slightly below, the GDT observed in the Ntorya-1 well. The P10 polygon includes the potentially connected downdip sand bodies and incorporates the possibility of a much deeper GWC far downdip of the existing well penetrations.

			P90	P50	P10
Area	sq. km	Lognormal	60	92	140
Thickness	m	Normal	20	40	60
Shape factor	Fr	Triangular	0.96 (min)	0.98 (mode)	1 (max)
Degree of fill	%	Single	–	100	–
Net to Gross	%	Normal	40	60	80
Porosity	%	Normal	12	15.5	19
Water Saturation	%	Normal	20	30	40
FVF	scf/rcf	Normal	222	238	254

Table 5-4: Volumetric Input Parameters for Combined Ntorya Case A and Case B

The gas-in place for Cases A & B are given in Table 5-5.

	P90	P50	P10	Mean
Case A (Bscf)	41	135	452	208
Case B (Bscf)	669	1,642	3,363	1,870

Table 5-5: GIIP Estimates for Ntorya Case A & Case B

5.5 *Development Plan*

The operator does not currently have an approved development plan for the field. The initial intention is to use the existing two exploration/appraisal wells (Ntorya-1 and Ntorya-2) as development wells together with the planned Chikumbi-1 well which is expected to be drilled in Q2 2019. Ndovu has two development cases. Case A, contains the initial three well development (two of the wells already drilled and the third will be drilled in Q2 2019). Case B, contemplates a further development of an additional eight wells based on the minimum number of wells required to reach the facilities availability of 140 MMscf/d. A pipeline will connect the well heads to Madimba Processing Plant.

5.6 *Production Forecasts*

The first step to define the production forecast was to create well models based on the well test data, to define their deliverability. Using the nodal analysis software Prosper®, initial IPR curves for the wells were established using a multi-rate model. The IPR curves that RPS defined are in agreement with the ones defined by the operator.

Subsequently, a set of vertical lift performance curves were also defined, initially based on the well test completion size, to choose the best correlation possible. RPS assumes the wells will be recompleted for development later and assessed different completion sizes. A set of VLP curves were defined to cover the entire range of pressures expected during the development phase.

Once the well models were defined, two material balance models using PETEX package Mbal® were created. Case A, contains the initial three well development (two of the wells already drilled and the third will be drilled in 2018). Case B, contemplates a further development of an additional eight wells based on the minimum number of wells required to reach the facilities availability of 140 MMscf/d, based on the existing well tests.

In addition, in order to include the pipeline connecting the well heads to Madimba Processing Plant, the Mbal® models were incorporated to a GAP® model to calculate the WHP of the wells given the required arrival pressure at the plant.

The assumptions use for each of the cases are summarised in Table 5-6.

		A LOW	A BASE	A HIGH	A+B LOW	A+B BASE	A+B HIGH
ASSUMPTIONS	**Downtime (%)**	10%	7%	5%	10%	7%	5%
	Pipeline	33 km, 18" diameter					
	Plateau rate (MMscf/d)	30 (Avg=27)	40 (Avg=47.5)	50 (Avg=47.5)	140 (Avg=126)	140 (Avg=130.2)	140 (Avg=133)
	Drilling sequence	3 wells predrilled			3 wells predrilled plus 4th after 9 months then 1 well every 3 months up to a **total of 11 wells**		
	IRP	Same as well test					
	Completion diameter	4" OD					
	Arrival pressure @ Mandimba	70 Bar					

Table 5-6: Ntorya Models Assumptions

The profiles obtained are illustrated in Figure 5-11.

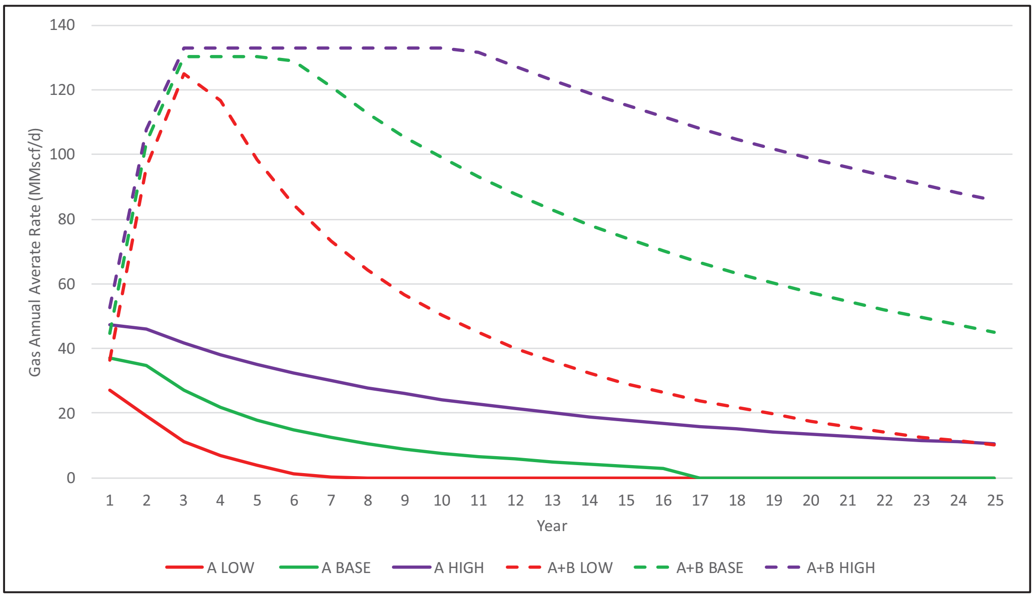


Figure 5-11: Ntoyra Annualised Gross Profiles

5.7 *Development Cost Estimates*

The initial production scheme, Case A, is designed to produce from three wells with flowlines tied to a central manifold. Onward transmission to the Madimba plant is via a 18” line. This is expected to be supplemented by a further eight wells, Case B, to absorb the remaining plant ullage. Flow assurance has been assessed with no significant issues foreseen.

5.7.1 *Case A*

The scheme consists of a gathering system of flowlines tied back to a central manifold which exports the gas via a 33 km x 18” pipeline to the Madimba gas processing plant which is known to have a current available ullage of approximately 170 MMscf/d. In the base case peak production is estimated at just under 40 MMscf/d with the high case at 50 MMscf/d.

Costs for the Case A, including pipeline, are fairly minimal at about $48 MM. The costs were provided by Ndovu and, on consultation with the provider, are said to include Indirect Costs (Design Engineering, Project Management, Insurances, etc.). RPS has allocated a contingency of 25% for unforeseen growth and possible construction issues. Total capex for the scheme is $60 MM.

Drilling costs are again provided by Ndovu with 2 existing wells being re-completed at $4 MM each and one new vertical well at $15 MM. RPS has included a 15% contingency on these costs to give an overall drilling total of $26.5 MM.

Operating costs were estimated by the client at $2.30MM/annum. RPS considers this to be on the low side and has added a small variable Opex to compensate.

Abandonment costs are included at $9MM representing 7% of Capex and plugging three wells at $1.5MM each.

5.7.2 *Case B*

RPS is proposing an 'Intermediate Development Scheme', Case B, whereby further wells could be drilled to take up much of the remainder of the Madimba plant capacity. It is recognised that the field has further upside potential which would necessitate a future processing plant upgrade (Madimba) or a dedicated processing plant located within the field. Export options would require further examination but there is a possibility of a tie-in to the main 36" trunkline to Dar es Salaam.

Case B will require the drilling of eight additional wells taking the throughput to 130 MMscf/d. Capex for this scheme has been extrapolated from Ndovu estimates and assumes the installation of a twin line to Madimba. Overall Facilities costs are estimated at $150 MM and includes the EPS. Note that based on other current producing projects, TPDC will likely build the pipeline.

Drilling costs for the 8 additional wells are $140 MM including contingency. Operating costs have been increased to $7.50 MM/annum to accommodate the additional facilities and wells. Abandonment costs are included at $27 MM for well plugging and land re-instatement.

5.8 ***Environmental and HSE Aspects of Infrastructure***

The facilities under consideration are yet to be constructed. Ndovu commits to the implementation of its HSE management system, as described below, during the design, construction and ongoing production and ultimately abandonment of the facilities to be in place on the Ntorya field. Ndovu advised RPS that the HSE management system has been successfully implemented on the development of the Kilwani North field in Tanzania, which Ndovu advises, has resulted in a high standard of HSE performance resulting in no significant accidents or incidents to date. This system will be tailored to the requirements of the Ntorya field with project specific processes and plans implemented which should achieve a similarly high level of HSE performance.

Given the onshore location of the Ntorya field, Ndovu advises that a comprehensive Environmental & Social Impact Assessment (ESIA) process will be followed as part of the planning stages of the development. The ESIA and resulting Environmental and Social Management Plan (ESMP) will assess and where possible mitigate the risks associated with resource use specific to the proposed development. Occupational Health and Safety (OH&S) will be managed throughout the construction, commissioning and ongoing production phases to ensure that the high standard of OH&S achieved across the assets previously built and operated by Ndovu, will be continued on the Ntorya assets.

5.8.1 *Ndovu's Health, Safety and Environment Management System (HSEMS)*

Ndovu as Operator of all its assets, and its parent company Aminex PLC (Aminex), has a commitment to health and safety which is expressed in its corporate statement:

Aminex values the safety and health of all our employees, contractors and the wider community in which it operates. As standard practice, Ndovu:

- does not compromise on safety;

- complies with legislative requirements;
- identifies, assesses and manages environmental health and safety hazards, risks and impacts;
- promotes continuous improvement practices within all aspects of the business;
- minimises workplace exposure to hazards;
- understands and works to meet the expectations of the community;
- provides appropriate training to employees and contractors to ensure occupation, health and safety responsibilities are understood.

RPS has reviewed the Framework Document of the Ndovu Health, Safety and Environment Management System (HSEMS) which forms the basis of the HSE programmes, with specific procedures and training implemented for each type of activity. Project Specific Health, Safety and Environment (HSE) programmes are prepared for each type of activity, including project-specific Emergency Response Plan (ERP). RPS considers that this HSEMS Framework Document meets industry standards, however the full implementation of the system has not been reviewed by RPS. Ndovu advises that its activities and operations in Tanzania to date have maintained an impeccable HSE record that complies with the Tanzanian laws and continues its commitment to health and safety and good community engagement.

5.9 ***Economic Evaluation***

5.9.1 *Introduction*

Net entitlement volumes from Contingent Resources for Ntorya licence have been calculated using a spreadsheet-based discounted cash flow model. The model calculates annual Ndovu after tax project cash flows based on forecasts of future production and costs, the applicable fiscal and contract terms and the economic assumptions listed below. These calculations are necessary in order to calculate the sharing of the Cost petroleum and the Profit Share to determine Ndovu Net Entitlement under a PSA type of contract.

The lack of an approved development plan for the field leads RPS to classify the produced volumes as Contingent Resources under the following two subcategories:

Contingent – Development Pending (CDP): As the CDP project must be economic, we have therefore assessed the future economic viability of this case on the basis of its post tax NPV using an industry-standard 10% discount rate.

Contingent – Development Unclarified (CDU): This incremental project (CDU), together with the CDP project will produce a Total Contingent Case of 11 wells.

The potential project’s resources are calculated incrementally from the Total Contingent Resource case, as follow:

- o 1C CDU = 1C Total Contingent - 2C CDP
- o 2C CDU = 2C Total Contingent - 2C CDP
- o 3C CDU = 3C Total Contingent - 2C CDP

5.9.2 *Commercial Terms and Economic Assumptions*

Ndovu has a 75% working interest in the Ntorya Licence, which is subject to the Ruvuma PSA.

The Development Licence is at present under negotiation. Aminex suggested that there are many reasons to expect similar Fiscal Terms as the Kiliwani North development licence. Given the lack of approved fiscal terms and considering the status of Contingent Resources, it has been assumed fiscal and commercial terms similar as suggested:

- **Grant of a development licence for 25 years**
- **Royalty** is payable at 12.5% by the Tanzania Petroleum Development Corporation (TPDC)

- **Local Levy** of 0.3% applicable on revenues.
- **Cost Recovery:** all costs considered as Recoverable Contract Expenses may be recovered from petroleum revenue limited to an amount not exceeding 40% to 60% for Oil and 60% for Gas.

  Any unrecovered cost is allowed to be carried forward into subsequent years without restriction.

  Recovered costs include Opex, Capex (depreciation) and Abandonment costs. Any excess of Cost petroleum after having recovered all costs is automatically considered as part of the profit petroleum and distributed according to the profit sharing terms.
- **Profit Sharing:** the method applicable for establishing the profit sharing between the government and the contractor is calculated as shown in Table 5-7 and Table 5-8.

Gas Produced (MMscf/d)	TPDC Share	Contractor's Share
up to 49.999	30.0%	70.0%
51.0 to 99.999	40.0%	60.0%
101.0 to 199.999	50.0%	50.0%
201.0 to 399.999	60.0%	40.0%
over 399.999	70.0%	30.0%

Table 5-7: Gas Profit Share

Oil Produced (stb/d)	TPDC Share	Contractor Share
up to 8,333	27.5%	72.5%
8,334 to 16,666	35.0%	65.0%
16,667 to 33,333	40.0%	60.0%
33,334 to 66,666	45.0%	55.0%
66,667 to 83,333	50.0%	50.0%
over 83,333	55.0%	45.0%

Table 5-8: Oil Profit Share

- **Corporate Income Tax (CIT):** The effective income tax rate applicable is 30.0%, calculated considering the following main deductions:
  - o Operating Costs
  - o Tangible Capital Costs: depreciation based on 20% straight line method
  - o Intangible Capital Costs: 100% write-off in year spent

The following assumptions have been included in the economic model:

- **Gas price:** has been provided by Aminex, assuming a $3.18/Mscf Gas Price up until 31 December 2014, which indexed by the US CPI produced a $3.27/Mscf 2017 real.
- **Inflation:** of 2% per annum from 2017 onwards for costs and prices.

5.9.3 *Contingent Resources*

Given that the licence has expired and is subject to renegotiation and that a field development plan has not been approved, the hydrocarbon volumes are classified as Contingent Resources. The first phase (Case A) is sub-classified as Development Pending and the second phase (Case B) as Development Unclarified. As these are Contingent Resources, no economic cut off has been applied to these volumes. However, it was assumed volumes are produced up to the assumed expiry date of the, still to be ratified, 25-year development licence. Both phases are economically viable. Ndovu's Net Entitlements of Gas Contingent Resources, at the 1C, 2C and 3C levels are summarised in Table 5-9:

	Gas Contingent Resources (Bscf)[1]									Pd[4] (%)
	Gross (100%) Licence Basis			Ndovu's Net Working Interest Basis[2]			Ndovu's Net Entitlement Basis[3]			
	1C	2C	3C	1C	2C	3C	1C	2C	3C	
Development Pending	26	81	213	19	60	160	16	52	123	75
Development Unclarified	342	682	945	257	512	712	195	354	466	25

1. Assuming Development Licence is ratified
2. Ndovu Working Interest is 75%
3. Ndovu net entitlement is based on Ndovu share of Cost Oil and Profit Oil calculated using the assumed PSA terms
4. Pd is Chance of Development

Table 5-9: Ndovu's Net Entitlement Gas Contingent Resources

6 PROSPECTIVE RESOURCES

6.1 *Chikumbi Prospect*

The planned Chikumbi-1 (CH-1) well will be drilled within the Mtwara Licence area to a planned total depth of 3,485m TVD to test the Late Jurassic stratigraphically trapped Chikumbi prospect whilst also appraising an extension to the Cretaceous Ntorya discovery.

The primary target for the CH-1 well is Late Jurassic sandstones that lie under the Base Cretaceous Unconformity, directly beneath the Ntorya discovery. The seismic shows stacked lobes with elevated amplitudes and overall thickening of the Tithonian interval (Figure 6-1). Seismic line 121 is aligned along the length of the prospect and shows lateral downlap and seismic amplitude changes that delineate the length of the prospect as ~10 km. Lines 117 and MT07-24 define the width of the prospect, where MT07-24 shows possible downcutting and lateral confinement of the prospect. The structure gradually shallows to the northwest (Figure 6-2).

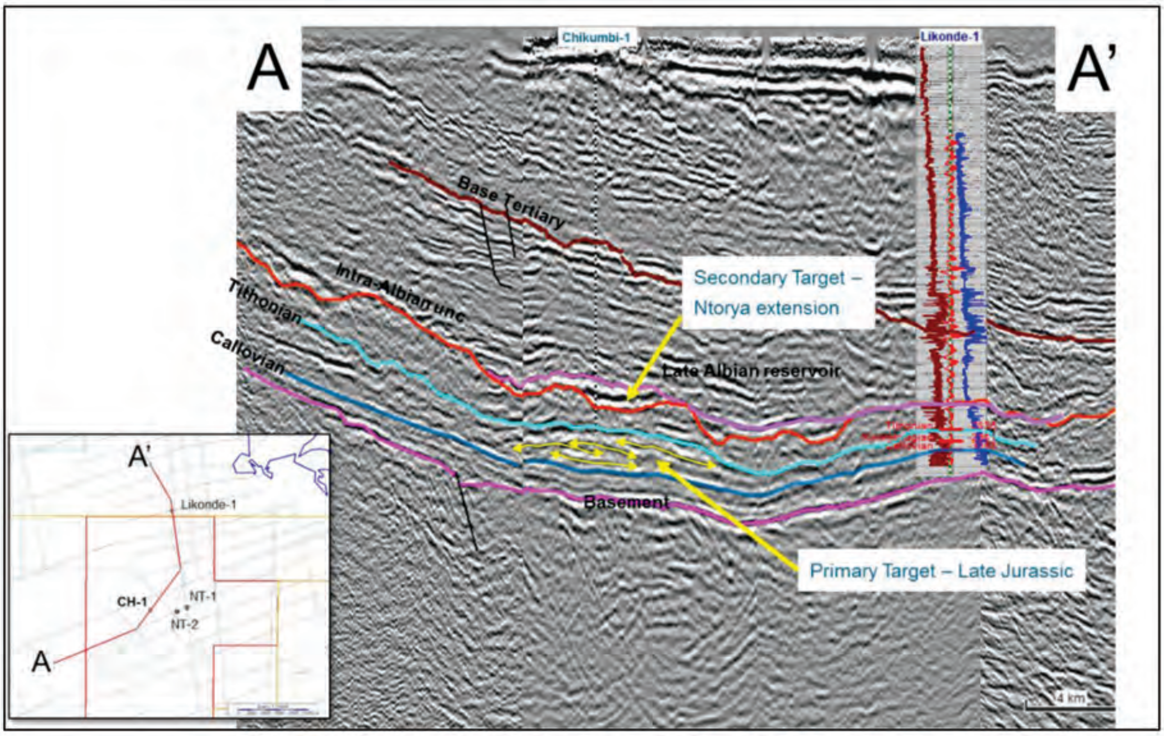


Figure 6-1: Seismic Section Showing Primary and Secondary Targets of Chikumbi-1

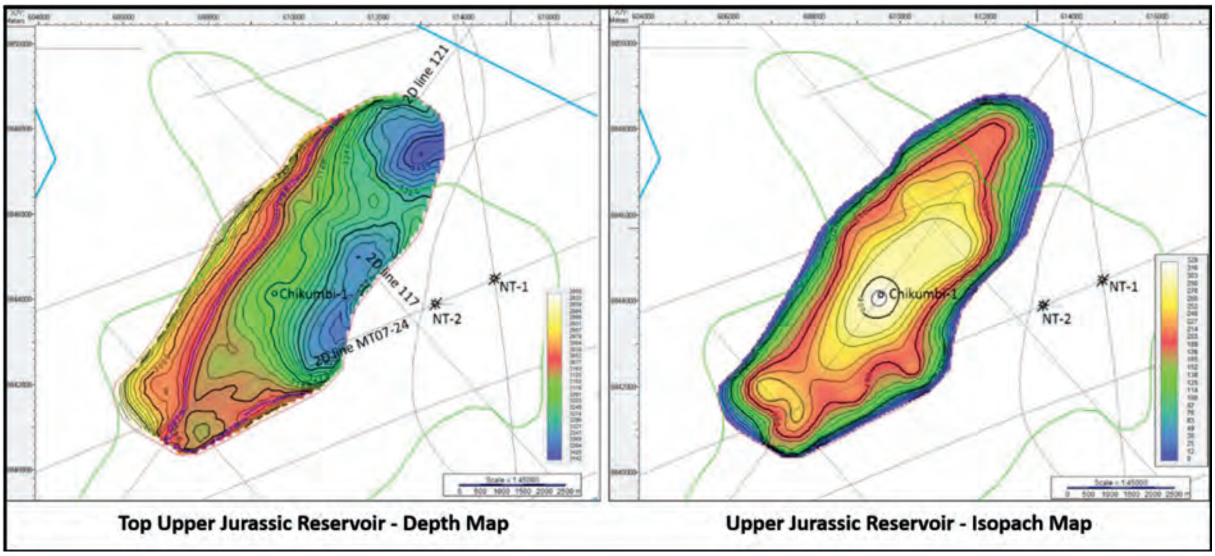


Figure 6-2: Left – Top Upper Jurassic Reservoir Depth and Isopach Maps at Chikumbi-1

The gross Late Jurassic interval can be correlated on the seismic into the Likonde-1 well located 14 km to the north. In Likonde-1, the Chikumbi reservoir interval correlates into approximately 250m of interbedded claystones, siltstones and sandstones (~3,000-3,250m MD). The biostratigraphy report for the well suggests this interval was deposited in the inner or middle neritic zone. The 'Late to Middle Jurassic undifferentiated' interval below this in Likonde-1 (~3,250-3,500m MD) is dominated by sandstone and is reported in the Final Well Report to have a net:gross of 17% and porosity of 13.5% (using cutoffs of VCL<=0.5 and PHIE>=0.1). The biostratigraphy report suggests this interval is probably shallow marine with a fluvial influence. Two possible depositional environments have been presented for Chikumbi by Ndovu in the provided data, turbidites and delta lobes. The evidence from Likonde-1 suggests that Ndovu's preferred interpretation of a delta is more likely.

RPS has generated probabilistic volumetrics for the Late Jurassic prospect. The input parameters are presented in Table 6-1. Ndovu depth maps for the top and base surfaces were input into REP and used to calculate GRV. Due to poor data quality, there is still a significant amount of interpretation uncertainty in the extent and thickness of the gross reservoir interval. The gas-water contact in Chikumbi is completely unknown and there is no evidence from seismic to assist in defining the GWC. The maximum column height from the interpreted structure is ~600m, but it is considered that a realistic scenario is closer to 300m. A range has been specified for ‘degree of fill’ to represent the possible GWCs that could be encountered. A wide range has been given for net to gross as there is considerable uncertainty relating to the environment of deposition given the paucity of analogue reservoirs at the same interval in the vicinity. Core in the Late Jurassic in Lukuledi-1 (50km NW of Chikumbi-1) records porosities of around 18% at depths of 1,100-1,270m MD. The prognosed depth of the reservoir in Chikumbi-1 is significantly deeper at 3,081m MD (2,896m TVDSS). Good quality reservoir in the Cretaceous turbidites at Ntorya have porosities of approximately 16% and petrophysics for Mid to Late Jurassic shallow marine sands in Likonde-1 suggest porosities of ~13%. There are no direct analogues for water saturation, so a wide range of values have been applied.

PRMS 2018 requires that estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources. Given the major uncertainties involved at this early stage, the development program will not be of the detail expected in later stages of maturity. In most cases, recovery efficiency may be based largely on analogous projects. Based on typical recovery factors for gas fields, a notional P90-P50-P10 recovery factor range of 60%-70%-80% has been used.

Parameter	Unit	Distribution	P90	P50	P10
Gross rock volume	Bcm	–	6.0	7.0	8.1
Area uncertainty	%	Normal	80	100	120
Degree of fill	%	Normal	40	50	60
Net to gross	%	Normal	20	45	70
Porosity	%	Normal	13	16	19
Water saturation	%	Normal	20	35	50
Gas expansion factor	scf/rcf	Normal	225	250	275
Recovery Factor	%	Normal	60	70	80

Table 6-1: Chikumbi Volumetric Input Parameters

The main risks for the Chikumbi prospect are the presence and effectiveness of the reservoir and the effectiveness of the stratigraphic trap. RPS has estimated a Pg of 8%. The estimated range of GIIP and Prospective Resources are given in Table 6-2.

GIIP (Bscf)[1]			Prospective Resources (Bscf)[1]						Pg[2] (%)
Gross on Licence			Gross on Licence			75% Working Interest			
1U (P90)	2U (P50)	3U (P10)	1U (P90	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
589	1,351	2,522	399	936	1,798	299	702	1,350	8

1. Assuming Development Licence is ratified
2. Pg is Chance of Geological Discovery

Table 6-2: GIIP and Prospective Resources in Chikumbi Prospect (below Ntorya Development)

The CH-1 well is appropriately located to appraise an extension to the Ntorya discovery. The well is located in a relative thick according to the seismic and is expected to encounter a significantly thicker gross reservoir interval compared to Ntorya-1 and Ntorya-2. Further details on Ntorya can be found in Section 5.

6.2 *Other Prospectivity in the Mtwara Licence*

Assuming Ndovu is successful in extending the Mtwara licence in the Ruvuma PSA there are Cretaceous and Tertiary leads in this area which present potential targets for further exploration. The trapping mechanisms are primarily stratigraphic and require good seismic control to confirm trap integrity. The current legacy sparse, multi-vintage 2D is inadequate to confirm likely trap integrity and define drill locations. Ndovu has proposed a 4x8 km 2D grid (Figure 6-3) for acquisition should the licence extension be successful. This will significantly improve prospect definition. However, RPS believes that consideration should be given to extending the area of the proposed Ntorya 3D to include near field exploration and potential downdip extension of the Ntorya field.

RPS has not independently evaluated the exploration potential in this block. However, RPS has reviewed the prospects and leads as evaluated by Senergy in the 2015 CPR. A list of the leads identified by RISC Advisory in 2012 are also included for completeness. The primary risks are trap definition and effective gas charge.

As noted above, PRMS 2018 requires that estimates of recoverable quantities must be stated in terms of the production derived from the potential development program even for Prospective Resources and in most cases, recovery efficiency may be based largely on analogous projects. Senergy appears to have used typical recovery factors for gas fields. Little new data has been acquired within the Ruvuma PSA, with the exception of the Ntorya-2 well, since the writing of the Senergy CPR. The Ntorya-2 well proves up the Ntorya field however does little to de-risk the prospects in the Ruvuma PSA area due to its proximity to Ntorya-1.

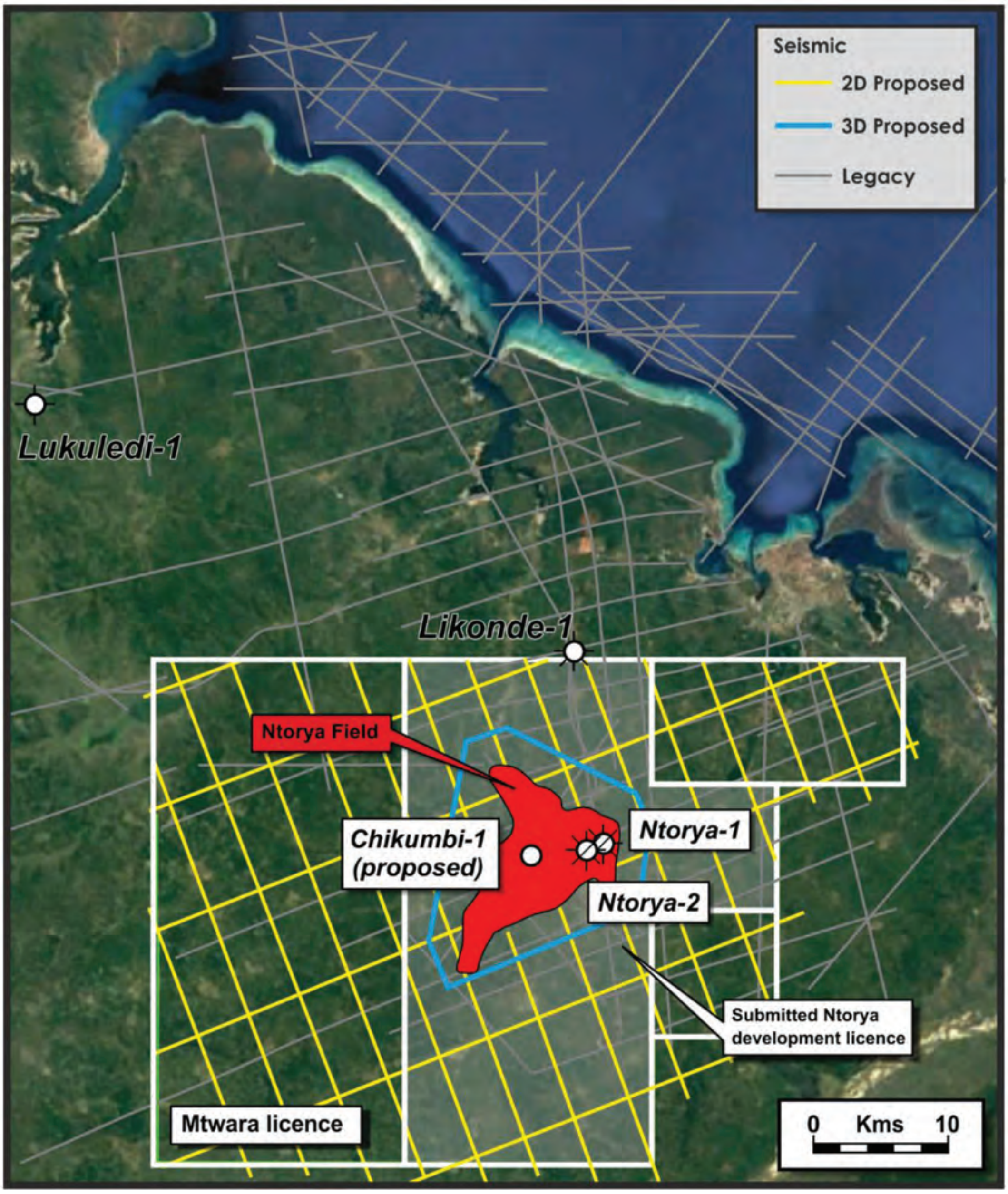


Figure 6-3: Ndovu Ruvuma PSA seismic program

The location of leads as defined by Senergy/RISC in the Ruvuma PSA are shown in Figure 6-4. Further seismic and studies by Ndovu may result in new potential traps being identified and some may be matured to drillable prospects; some previous leads may not be confirmed. The estimated volumetric ranges and risk summary of the Senergy high graded leads are shown in Table 6-3 and are discussed in Sections 6.2.1 to 6.2.3.

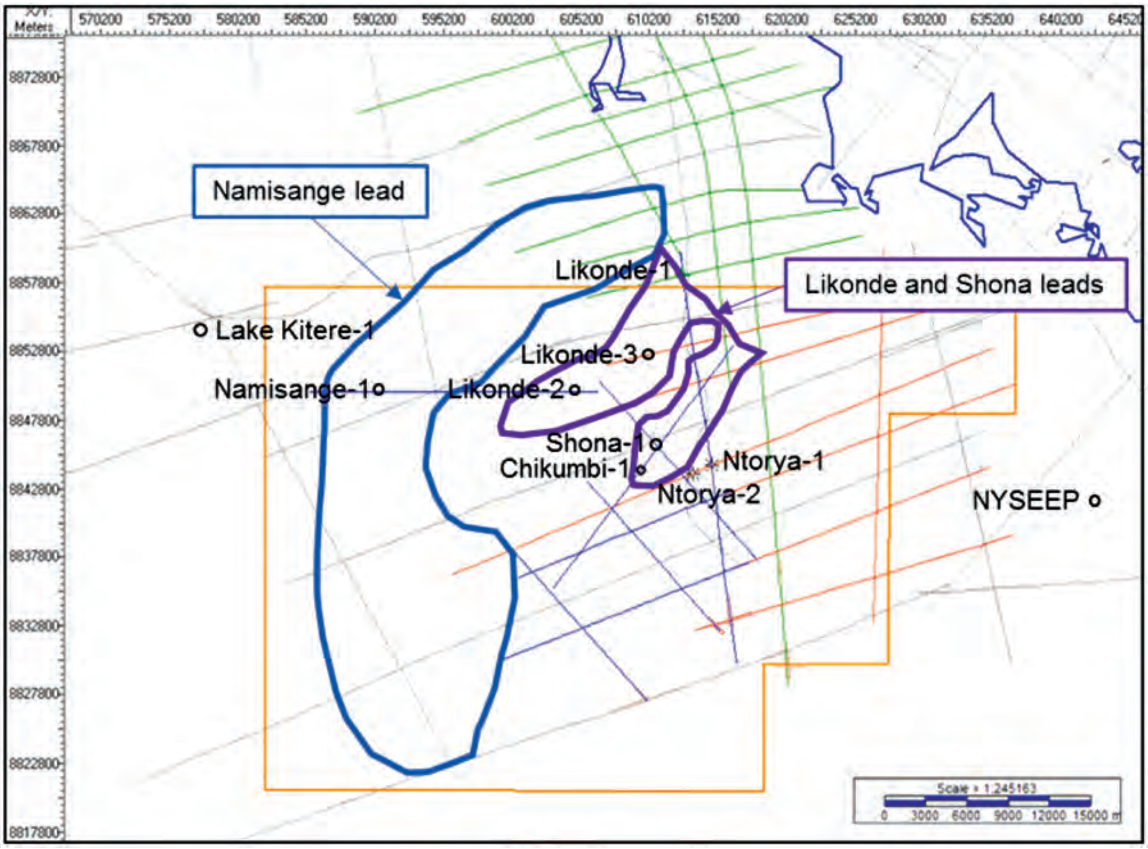


Figure 6-4: Location of Ruvuma PSA Leads

Lead	GIIP (Bscf)[1]			Prospective Resources (Bscf)[1]						Pg[2] (%)
	Gross on Licence			Gross on Licence			75% Working Interest			
	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
Namisange	81	467	2,762	56	325	1,925	42	244	1,444	8
Likonde Updip	57	239	1,006	39	166	702	29	125	527	10

1. Assumes PSA term is extended
2. Pg is Chance of Geological Discovery

Table 6-3: Prospective Resource Resources in High-Graded Leads Reviewed by Senergy[7]

6.2.1 *Likonde Updip Lead*

The Likonde updip lead is a potential lower Tertiary stratigraphic trap located updip of the Likonde-1 well (Figure 6-4). The well encountered a 96.5 m net reservoir sandstone of Oligocene age resting on the Base Tertiary Unconformity. No hydrocarbons were encountered at this level. The Likonde section also contains thick shale sequences which appear capable of sealing significant hydrocarbon columns. No particular source rock sequences have been identified in the well, but the presence of oil shows in the Cretaceous and Jurassic suggests an active petroleum system is present in the area. Likonde-1 may have failed due to the absence of a trap. However, new seismic interpretation indicates that the Likonde fan may extend further updip than had been previously recognised. There is therefore significant remaining potential updip of the well.

7 Competent Persons Report Resource Assessment of the Assets of Aminex in Tanzania, Senergy, May 2015

The trap is stratigraphic, analogous to the discovery in the Ntorya-1 upper gas bearing sandstones; it comprises a channel-like body with stratigraphic updip pinchout. The fan appears to consist of two arms that converge downdip to the northeast. RPS recommends that each arm be defined as a separate prospect. The seismic control is sparse and different detailed interpretations are possible, so the trap is poorly constrained. However, the proposed new seismic acquisition should significantly improve trap definition.

The prospective resource assessment as performed by Senergy appears reasonable for this lead (Table 6-3). Given the proximity to the Ntorya field, RPS recommend reviewing the location of the planned Chikumbi-1 well to ensure a confident test of the southeastern arm Likonde Updip Lead. The results of drilling the southeast arm do not provide a test of the northwest arm and so the northwest arm should be considered as a separate lead/prospect.

6.2.2 *Namisange Lead*

The Namisange lower Cretaceous lead is located to the west and updip of Ntorya. The Namisange channel has been mapped by Senergy as trending northwards rather than northeast for the Ntorya channel. The channel fill is a series of relatively high amplitude events and appears to be more organised than the Ntorya channel. It is unclear, with the current seismic quality, if this represents a sandstone-shale package or high amplitude shales or marls or possibly a hydrocarbon indicator.

The Namisange channel is mapped on an irregular grid of approximately 5 2D seismic lines at typically 10 km spacing. The trap is stratigraphic, analogous to the discovery in the Ntorya-1 upper gas bearing sandstones; it comprises a channel-like body with stratigraphic updip pinchout to the west (Figure 6-4). The seismic control is sparse and different detailed interpretations are possible, so the trap is poorly constrained. The proposed seismic acquisition program should improve the definition of trap integrity.

The prospective resource assessment as performed by Senergy appears reasonable for this lead (Table 6-3).

6.2.3 *Additional Leads*

Additional leads have also been identified in the Ntorya permit by RISC (Table 6-4). RPS has made a brief review of these leads and conclude that they are very speculative and additional seismic will be required to mature the leads into drillable prospects. RISC does not provide an estimate of Pg. RPS has estimated Pg to be less than 5%.

Lead	GIIP (Bscf)[1]			Prospective Resources (Bscf)[1]						Pg[2,3] (%)
	Gross on Licence			Gross on Licence			75% Working Interest			
	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	1U (P90)	2U (P50)	3U (P10)	
Ziwani NW	n/a	n/a	n/a	8	35	153	6	26	115	<5%
Ziwani SW	n/a	n/a	n/a	12	54	236	9	41	177	<5%

1. Assumes PSA term is extended
2. RPS assessment of Pg (RISC did not include risking)
3. Pg is Chance of Geological Discovery

Table 6-4: Prospective Resources of Other Leads (RISC 2012)

7 QUALIFICATION OF RPS

RPS Energy is an independent energy advisory consultancy, part of the London-listed RPS Group plc. RPS has acted as independent evaluator in the analyses described in this Report and in arriving at the opinions expressed herein.

RPS's remuneration for preparing this Report has been based on hourly fees, agreed in the Letter of Engagement, charged on a time-written basis. No element of the remuneration was contingent on the results presented in this Report. The management and employees of RPS involved in this project were, and continue to be, independent of Ndovu Resources Ltd in the services they provided to Ndovu Resources Ltd and have no interest in the assets evaluated.

In performing this study, RPS is not aware that any conflict of interest has existed.

Eleanor Rollett has managed the project and supervised the preparation of the Report. Eleanor Rollett attended the University of Glasgow and graduated with a Bachelor of Science degree in Geology in 1990. She is a Fellow of the Geological Society and has been a Chartered Geologist since 2016. Ms Rollett has over 20 years' experience in the hydrocarbon exploration and production industry including the conduct of evaluation studies relating to oil and gas fields.

Gordon Taylor reviewed and signed-off this Report. Gordon Taylor attended the University of Birmingham and graduated with a Bachelor of Science degree in Geological Sciences in 1978; and a Master of Science degree in Foundation Engineering in 1979. He is a Fellow of the Geological Society and has been a Chartered Geologist since 1991. He is a Member of the Institute of Materials, Mining and Metallurgy and has been a Chartered Engineer since 1983. He is a member of the American Association of Petroleum Geologists (AAPG) through which he has been a Certified Petroleum Geologist since 2007. He is also a Member of the Society of Petroleum Engineers. Mr Taylor has in excess of 35 years' experience in the hydrocarbon exploration and production industry including the conduct of evaluation studies relating to oil and gas fields.

APPENDIX A: GLOSSARY OF TERMS AND ABBREVIATIONS

1C	Denotes low estimate of Contingent Resources
2C	Denotes best estimate of Contingent Resources
3C	Denotes high estimate of Contingent Resources
1U	Denotes the unrisked low estimate qualifying as Prospective Resources
2U	Denotes the unrisked best estimate qualifying as Prospective Resources
3U	Denotes the unrisked high estimate qualifying as Prospective Resources
AVO	Amplitude versus Offset
B	Billion
Bcm	billion cubic metres
B_g	gas formation volume factor
B_{gi}	gas formation volume factor (initial)
B_o	oil formation volume factor
B_{oi}	oil formation volume factor (initial)
boe	Barrels of oil equivalent
BHP	Bottom hole pressure
Bscf	billions of standard cubic feet
bwpd	barrels of water per day
condensate	liquid hydrocarbons which are sometimes produced with natural gas and liquids derived from natural gas
EMV	Expected Monetary Value
EUR	Estimated Ultimate Recovery
ft	Feet
FWL	Free Water Level
GDT	Gas Down To
GIIP	Gas Initially in Place
GRV	gross rock volume
GWC	gas water contact
IPR	Inflow performance relationship
km	Kilometres
LPG	Liquefied Petroleum Gases
m	Metres
m^3	cubic metres
m^3/d	cubic metres per day
M	Thousand

M$	thousand US dollars
MBAL	Material balance software
Mstb	thousand barrels
mD	permeability in millidarcies
MD	measured depth
MDT	Modular formation dynamics tester tool
MM	Million
MMscf/d	millions of standard cubic feet per day
MMstb	million stock tank barrels (at 14.7 psi and 60° F)
MMt	millions of tonnes
MM$	million US dollars
m/s	metres per second
Msec	Milliseconds
NTG or N:G	net to gross ratio
NGL	Natural Gas Liquids
NPV	Net Present Value
OWC	oil water contact
P90	There is estimated to be at least a 90% probability (P90) that this quantity will equal or exceed this low estimate
P50	There is estimated to be at least a 50% probability (P50) that this quantity will equal or exceed this best estimate
P10	There is estimated to be at least a 10% probability (P10) that this quantity will equal or exceed this high estimate
Petrel	A geoscience and reservoir engineering software package
Petroleum	deposits of oil and/or gas
Phi	porosity fraction
PSDM	Pre-stack depth migrated seismic data
PSTM	Pre-stack time migrated seismic data
PVT	pressure volume temperature
REP™	A Monte Carlo simulation software package
RF	Recovery factor
RFT	repeat formation tester
SCAL	Special Core Analysis
scf	standard cubic feet measured at 14.7 pounds per square inch and 60° F
scf/d	standard cubic feet per day
scf/stb	standard cubic feet per stock tank barrel

sq. km	square kilometres
stb	stock tank barrels measured at 14.7 pounds per square inch and 60° F
stb/d	stock tank barrels per day
STOIIP	stock tank oil initially in place
S_w	water saturation
THP	tubing head pressure
Tscf	trillion standard cubic feet
TVDSS	true vertical depth (sub-sea)
TVT	true vertical thickness
TWT	two-way time
US$	United States Dollars
VLP	Vertical lift performance
Vsh	shale volume
WUT	Water Up To
φϕ	Porosity

APPENDIX B: 2018 SPE/WPC/SEG/AAPG/EAGE/SPEE/SPWLA RESERVE/RESOURCE DEFINITIONS

The following is extracted from the 2018 SPE/WPC/SEG/AAPG/EAGE/SPEE/SPWLA PRMS using the section numbering and spelling from PRMS.

1.1 Petroleum Resources Classification Framework

1.1.0.1 Petroleum is defined as a naturally occurring mixture consisting of hydrocarbons in the gaseous, liquid, or solid state. Petroleum may also contain non-hydrocarbons, common examples of which are carbon dioxide, nitrogen, hydrogen sulfide, and sulfur. In rare cases, non-hydrocarbon content can be greater than 50%.

1.1.0.2 The term resources as used herein is intended to encompass all quantities of petroleum naturally occurring within the Earth's crust, both discovered and undiscovered (whether recoverable or unrecoverable), plus those quantities already produced. Further, it includes all types of petroleum whether currently considered as conventional or unconventional resources.

1.1.0.3 Figure 1.1 graphically represents the PRMS resources classification system. The system classifies resources into discovered and undiscovered and defines the recoverable resources classes: Production, Reserves, Contingent Resources, and Prospective Resources, as well as Unrecoverable Petroleum.

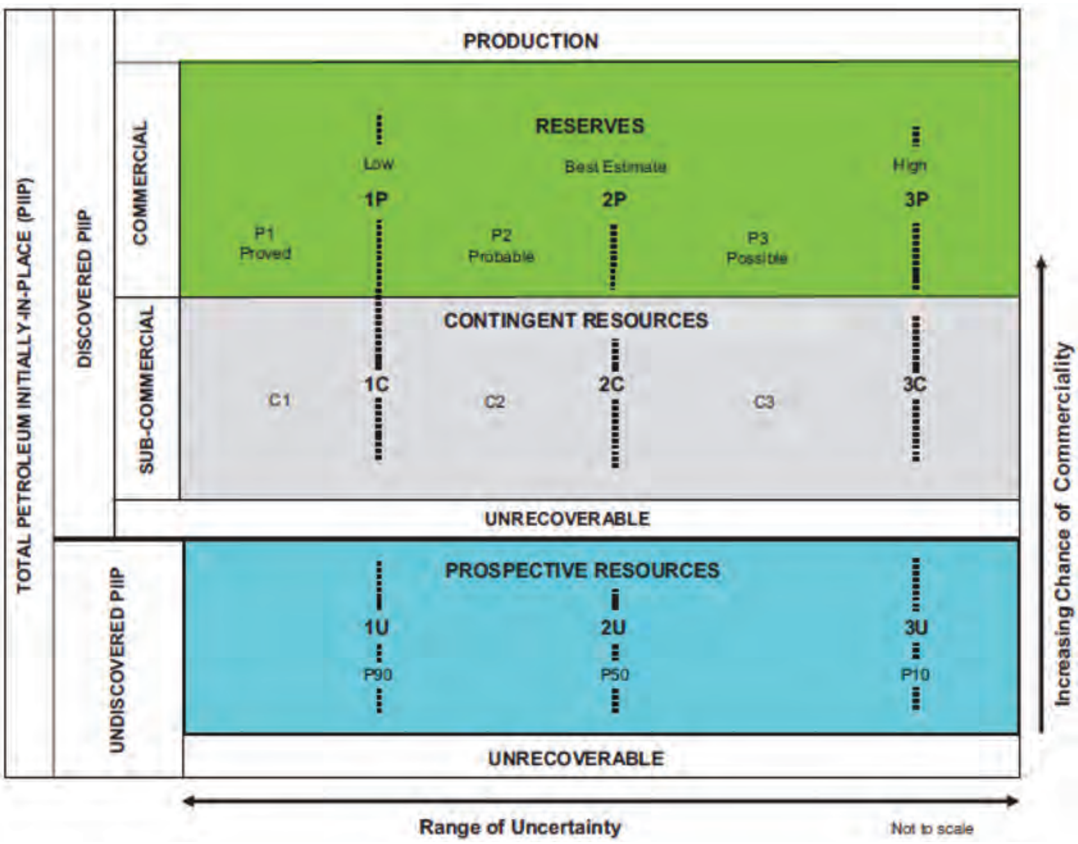


Figure 1.1 Resource Classification Framework

1.1.0.4 The horizontal axis reflects the range of uncertainty of estimated quantities potentially recoverable from an accumulation by a project, while the vertical axis represents the chance of commerciality, Pc, which is the chance that a project will be committed for development and reach commercial producing status.

1.1.0.5 The following definitions apply to the major subdivisions within the resources classification:

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

B. Discovered PIIP is the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations before production.

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

1.1.0.6 Multiple development projects may be applied to each known or unknown accumulation, and each project will be forecast to recover an estimated portion of the initially-in-place quantities. The projects shall be subdivided into commercial, sub-commercial, and undiscovered, with the estimated recoverable quantities being classified as Reserves, Contingent Resources, or Prospective Resources respectively, as defined below.

A. 1. Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining (as of the evaluation's effective date) based on the development project(s) applied.

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

3. Reserves are further categorized in accordance with the range of uncertainty and should be subclassified based on project maturity and/or characterized by development and production status.

B. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, by the application of development project(s) not currently considered to be commercial owing to one or more contingencies. Contingent Resources have an associated chance of development. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the range of uncertainty associated with the estimates and should be subclassified based on project maturity and/or economic status.

C. Undiscovered PIIP is that quantity of petroleum estimated, as of a given date, to be contained within accumulations yet to be discovered.

D. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of geologic discovery and a chance of development. Prospective Resources are further categorized in accordance with the range of uncertainty associated with recoverable estimates, assuming discovery and development, and may be sub-classified based on project maturity.

E. Unrecoverable Resources are that portion of either discovered or undiscovered PIIP evaluated, as of a given date, to be unrecoverable by the currently defined project(s). A portion of these quantities may become recoverable in the future as commercial circumstances change, technology is developed, or additional data are acquired. The remaining portion may never be recovered because of physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

1.2 Project-Based Resources Evaluations

1.2.0.1 The resources evaluation process consists of identifying a recovery project or projects associated with one or more petroleum accumulations, estimating the quantities of PIIP, estimating that portion of those in-place quantities that can be recovered by each project, and classifying the project(s) based on maturity status or chance of commerciality.

1.2.0.2 The concept of a project-based classification system is further clarified by examining the elements contributing to an evaluation of net recoverable resources (see Figure 1.2).

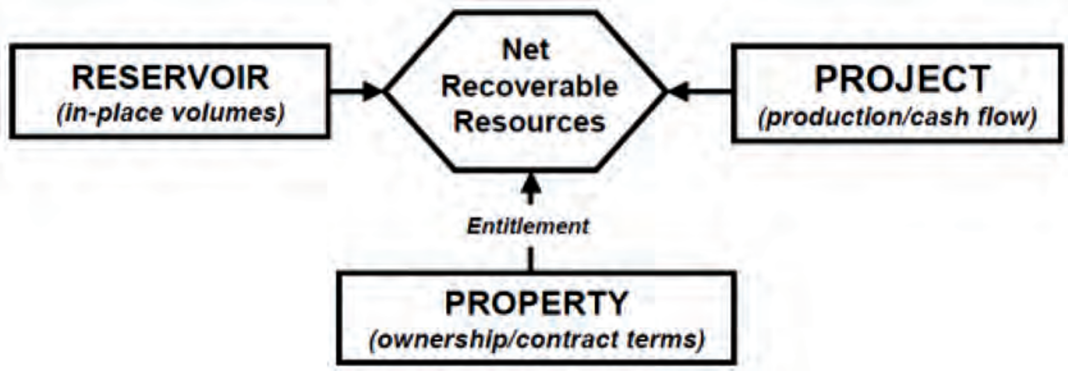


Figure 1.2 Resources evaluation[8]

1.2.0.3 The reservoir (contains the petroleum accumulation): Key attributes include the types and quantities of PIIP and the fluid and rock properties that affect petroleum recovery.

1.2.0.4 The project: A project may constitute the development of a well, a single reservoir, or a small field; an incremental development in a producing field; or the integrated development of a field or several fields together with the associated processing facilities (e.g., compression). Within a project, a specific reservoir's development generates a unique production and cash-flow schedule at each level of certainty. The integration of these schedules taken to the project's earliest truncation caused by technical, economic, or the contractual limit defines the estimated recoverable resources and associated future net cash flow projections for each project. The ratio of EUR to total PIIP quantities defines the project's recovery efficiency. Each project should have an associated recoverable resources range (low, best, and high estimate).

1.2.0.5 The property (lease or license area): Each property may have unique associated contractual rights and obligations, including the fiscal terms. This information allows definition of each participating entity's share of produced quantities (entitlement) and share of investments, expenses, and revenues for each recovery project and the reservoir to which it is applied. One property may encompass many reservoirs, or one reservoir may span several different properties. A property may contain both discovered and undiscovered accumulations that may be spatially unrelated to a potential single field designation.

1.2.0.6 An entity's net recoverable resources are the entitlement share of future production legally accruing under the terms of the development and production contract or license.

1.2.0.7 In the context of this relationship, the project is the primary element considered in the resources classification, and the net recoverable resources are the quantities derived from each project. A project represents a defined activity or set of activities to develop the petroleum accumulation(s) and the decisions taken to mature the resources to reserves. In general, it is recommended that an individual project has assigned to it a specific maturity level sub-class

8 There is typographical error in Figure 1-2 of PRMS 2018. RPS has used Figure 1-2 from the 2007 version

at which a decision is made whether or not to proceed (i.e., spend more money) and there should be an associated range of estimated recoverable quantities for the project. For completeness, a developed field is also considered to be a project.

APPENDIX C: PRODUCTION FORECASTS: NTORYA

			TECHNICAL RESOURCES			FORECAST FUTURE FIELD PRODUCTION (AFTER ECONOMIC CUT OFF)								
Year		Production Days	Gross Field Resources (100% Basis)			Gross Field Resources (100% Basis)			WI share of Gross Field Resources			Net Entitlement Resources		
			MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf
1	2017	365	-	-	-	-	-	-	-	-	-	-	-	-
2	2018	365	-	-	-	-	-	-	-	-	-	-	-	-
3	2019	365	-	-	-	-	-	-	-	-	-	-	-	-
4	2020	366	27.0	9.9	9.9	27.0	9.9	9.9	20.2	7.4	7.4	17.3	6.3	6.3
5	2021	365	19.3	7.0	16.9	19.3	7.0	16.9	14.5	5.3	12.7	12.3	4.5	10.8
6	2022	365	11.2	4.1	21.0	11.2	4.1	21.0	8.4	3.1	15.7	7.2	2.6	13.4
7	2023	365	6.8	2.5	23.5	6.8	2.5	23.5	5.1	1.9	17.6	4.4	1.6	15.0
8	2024	366	4.0	1.5	25.0	4.0	1.5	25.0	3.0	1.1	18.7	2.6	0.9	16.0
9	2025	365	1.4	0.5	25.5	1.4	0.5	25.5	1.0	0.4	19.1	0.9	0.3	16.3
10	2026	365	0.1	0.1	25.5	0.1	0.1	25.5	0.1	0.0	19.1	0.1	0.0	16.3
11	2027	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
12	2028	366	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
13	2029	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
14	2030	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
15	2031	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
16	2032	366	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
17	2033	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
18	2034	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
19	2035	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
20	2036	366	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
21	2037	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
22	2038	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
23	2039	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
24	2040	366	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
25	2041	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
26	2042	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
27	2043	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
28	2044	366	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
29	2045	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
30	2046	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
31	2047	365	-	-	25.5	-	-	25.5	-	-	19.1	-	-	16.3
	Sub Total			25.5			25.5			19.1			16.3	
	Total			25.5			25.5			19.1			16.3	

Ntorya Contingent Development Pending 1C Case

	Year	Production Days	TECHNICAL RESOURCES			FORECAST FUTURE FIELD PRODUCTION (AFTER ECONOMIC CUT OFF)								
			Gross Field Resources (100% Basis)			Gross Field Resources (100% Basis)			WI share of Gross Field Resources			Net Entitlement Resources		
			MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf
1	2017	365	-	-	-	-	-	-	-	-	-	-	-	-
2	2018	365	-	-	-	-	-	-	-	-	-	-	-	-
3	2019	365	-	-	-	-	-	-	-	-	-	-	-	-
4	2020	366	37.2	13.6	13.6	37.2	13.6	13.6	27.9	10.2	10.2	23.8	8.7	8.7
5	2021	365	34.8	12.7	26.3	34.8	12.7	26.3	26.1	9.5	19.7	22.3	8.1	16.8
6	2022	365	27.3	9.9	36.3	27.3	9.9	36.3	20.4	7.5	27.2	17.4	6.4	23.2
7	2023	365	21.7	7.9	44.2	21.7	7.9	44.2	16.3	5.9	33.1	13.9	5.1	28.3
8	2024	366	17.7	6.5	50.7	17.7	6.5	50.7	13.3	4.9	38.0	11.4	4.2	32.4
9	2025	365	14.8	5.4	56.1	14.8	5.4	56.1	11.1	4.0	42.1	9.5	3.4	35.9
10	2026	365	12.4	4.5	60.6	12.4	4.5	60.6	9.3	3.4	45.5	7.9	2.9	38.8
11	2027	365	10.5	3.8	64.4	10.5	3.8	64.4	7.9	2.9	48.3	6.7	2.5	41.3
12	2028	366	9.0	3.3	67.7	9.0	3.3	67.7	6.7	2.5	50.8	5.7	2.1	43.4
13	2029	365	7.7	2.8	70.5	7.7	2.8	70.5	5.8	2.1	52.9	4.9	1.8	45.1
14	2030	365	6.6	2.4	72.9	6.6	2.4	72.9	5.0	1.8	54.7	4.2	1.5	46.7
15	2031	365	5.7	2.1	75.0	5.7	2.1	75.0	4.3	1.6	56.3	3.7	1.3	48.0
16	2032	366	4.9	1.8	76.8	4.9	1.8	76.8	3.6	1.3	57.6	3.1	1.1	49.2
17	2033	365	4.1	1.5	78.3	4.1	1.5	78.3	3.1	1.1	58.7	2.6	1.0	50.1
18	2034	365	3.5	1.3	79.6	3.5	1.3	79.6	2.6	1.0	59.7	2.2	0.8	51.0
19	2035	365	2.7	1.0	80.6	2.7	1.0	80.6	2.1	0.8	60.4	1.8	0.6	51.6
20	2036	366	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
21	2037	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
22	2038	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
23	2039	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
24	2040	366	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
25	2041	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
26	2042	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
27	2043	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
28	2044	366	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
29	2045	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
30	2046	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
31	2047	365	-	-	80.6	-	-	80.6	-	-	60.4	-	-	51.6
	Sub Total			80.6			80.6			60.4			51.6	
	Total			80.6			80.6			60.4			51.6	

Ntorya Contingent Development Pending 2C Case

	Year	Production Days	TECHNICAL RESOURCES			FORECAST FUTURE FIELD PRODUCTION (AFTER ECONOMIC CUT OFF)								
			Gross Field Resources (100% Basis)			Gross Field Resources (100% Basis)			WI share of Gross Field Resources			Net Entitlement Resources		
			MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf
1	2017	365	-	-	-	-	-	-	-	-	-	-	-	-
2	2018	365	-	-	-	-	-	-	-	-	-	-	-	-
3	2019	365	-	-	-	-	-	-	-	-	-	-	-	-
4	2020	366	47.5	17.4	17.4	47.5	17.4	17.4	35.6	13.0	13.0	30.4	11.1	11.1
5	2021	365	46.0	16.8	34.2	46.0	16.8	34.2	34.5	12.6	25.6	29.4	10.7	21.9
6	2022	365	41.7	15.2	49.4	41.7	15.2	49.4	31.3	11.4	37.0	26.7	9.7	31.6
7	2023	365	38.1	13.9	63.3	38.1	13.9	63.3	28.6	10.4	47.5	24.4	8.9	40.5
8	2024	366	35.0	12.8	76.1	35.0	12.8	76.1	26.3	9.6	57.1	22.4	8.2	48.7
9	2025	365	32.3	11.8	87.9	32.3	11.8	87.9	24.2	8.8	65.9	20.7	7.5	56.3
10	2026	365	29.9	10.9	98.8	29.9	10.9	98.8	22.4	8.2	74.1	17.1	6.2	62.5
11	2027	365	27.8	10.2	109.0	27.8	10.2	109.0	20.9	7.6	81.7	14.8	5.4	67.9
12	2028	366	26.0	9.5	118.5	26.0	9.5	118.5	19.5	7.1	88.9	13.8	5.0	72.9
13	2029	365	24.3	8.9	127.3	24.3	8.9	127.3	18.2	6.6	95.5	12.9	4.7	77.6
14	2030	365	22.7	8.3	135.6	22.7	8.3	135.6	17.1	6.2	101.7	12.1	4.4	82.0
15	2031	365	21.3	7.8	143.4	21.3	7.8	143.4	16.0	5.8	107.6	11.3	4.1	86.2
16	2032	366	20.1	7.3	150.8	20.1	7.3	150.8	15.0	5.5	113.1	10.7	3.9	90.1
17	2033	365	18.9	6.9	157.6	18.9	6.9	157.6	14.2	5.2	118.2	10.0	3.7	93.7
18	2034	365	17.8	6.5	164.1	17.8	6.5	164.1	13.4	4.9	123.1	9.5	3.5	97.2
19	2035	365	16.8	6.1	170.3	16.8	6.1	170.3	12.6	4.6	127.7	9.0	3.3	100.5
20	2036	366	15.9	5.8	176.1	15.9	5.8	176.1	11.9	4.4	132.1	8.5	3.1	103.6
21	2037	365	15.0	5.5	181.6	15.0	5.5	181.6	11.3	4.1	136.2	8.0	2.9	106.5
22	2038	365	14.3	5.2	186.8	14.3	5.2	186.8	10.7	3.9	140.1	7.6	2.8	109.3
23	2039	365	13.5	4.9	191.7	13.5	4.9	191.7	10.1	3.7	143.8	7.2	2.6	111.9
24	2040	366	12.8	4.7	196.4	12.8	4.7	196.4	9.6	3.5	147.3	6.9	2.5	114.4
25	2041	365	12.2	4.4	200.9	12.2	4.4	200.9	9.1	3.3	150.7	6.5	2.4	116.8
26	2042	365	11.6	4.2	205.1	11.6	4.2	205.1	8.7	3.2	153.8	6.2	2.3	119.1
27	2043	365	11.0	4.0	209.1	11.0	4.0	209.1	8.3	3.0	156.8	5.9	2.2	121.2
28	2044	366	10.5	3.8	212.9	10.5	3.8	212.9	7.8	2.9	159.7	5.6	2.1	123.3
29	2045	365	-	-	212.9	-	-	212.9	-	-	159.7	-	-	123.3
30	2046	365	-	-	212.9	-	-	212.9	-	-	159.7	-	-	123.3
31	2047	365	-	-	212.9	-	-	212.9	-	-	159.7	-	-	123.3
	Sub Total			212.9			212.9			159.7			123.3	
	Total			212.9			212.9			159.7			123.3	

Ntorya Contingent Development Pending 3C Case

Ntorya Total Contingent:

	Year	Production Days	TECHNICAL RESOURCES			FORECAST FUTURE FIELD PRODUCTION (AFTER ECONOMIC CUT OFF)								
			Gross Field Resources (100% Basis)			Gross Field Resources (100% Basis)			WI share of Gross Field Resources			Net Entitlement Resources		
			MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf
1	2017	365	-	-	-	-	-	-	-	-	-	-	-	-
2	2018	365	-	-	-	-	-	-	-	-	-	-	-	-
3	2019	365	-	-	-	-	-	-	-	-	-	-	-	-
4	2020	366	36.3	13.3	13.3	36.3	13.3	13.3	27.2	10.0	10.0	23.3	8.5	8.5
5	2021	365	96.0	35.0	48.3	96.0	35.0	48.3	72.0	26.3	36.2	60.1	21.9	30.4
6	2022	365	125.2	45.7	94.0	125.2	45.7	94.0	93.9	34.3	70.5	77.2	28.2	58.6
7	2023	365	116.8	42.6	136.6	116.8	42.6	136.6	87.6	32.0	102.5	72.3	26.4	85.0
8	2024	366	98.5	36.1	172.7	98.5	36.1	172.7	73.9	27.0	129.5	61.6	22.6	107.6
9	2025	365	84.4	30.8	203.5	84.4	30.8	203.5	63.3	23.1	152.6	53.1	19.4	127.0
10	2026	365	73.4	26.8	230.3	73.4	26.8	230.3	55.0	20.1	172.7	40.3	14.7	141.7
11	2027	365	64.3	23.5	253.8	64.3	23.5	253.8	48.2	17.6	190.3	33.4	12.2	153.8
12	2028	366	56.8	20.8	274.5	56.8	20.8	274.5	42.6	15.6	205.9	30.0	11.0	164.8
13	2029	365	50.4	18.4	292.9	50.4	18.4	292.9	37.8	13.8	219.7	27.1	9.9	174.7
14	2030	365	44.9	16.4	309.3	44.9	16.4	309.3	33.7	12.3	232.0	24.2	8.8	183.5
15	2031	365	40.2	14.7	324.0	40.2	14.7	324.0	30.2	11.0	243.0	21.7	7.9	191.5
16	2032	366	36.0	13.2	337.2	36.0	13.2	337.2	27.0	9.9	252.9	19.6	7.2	198.6
17	2033	365	32.3	11.8	349.0	32.3	11.8	349.0	24.3	8.9	261.8	17.6	6.4	205.1
18	2034	365	29.1	10.6	359.6	29.1	10.6	359.6	21.8	8.0	269.7	16.0	5.8	210.9
19	2035	365	26.3	9.6	369.2	26.3	9.6	369.2	19.7	7.2	276.9	14.5	5.3	216.2
20	2036	366	23.8	8.7	378.0	23.8	8.7	378.0	17.9	6.5	283.5	13.2	4.8	221.0
21	2037	365	21.7	7.9	385.9	21.7	7.9	385.9	16.2	5.9	289.4	12.0	4.4	225.4
22	2038	365	19.6	7.2	393.0	19.6	7.2	393.0	14.7	5.4	294.8	11.0	4.0	229.4
23	2039	365	17.6	6.4	399.5	17.6	6.4	399.5	13.2	4.8	299.6	9.9	3.6	233.0
24	2040	366	15.7	5.8	405.2	15.7	5.8	405.2	11.8	4.3	303.9	8.9	3.3	236.3
25	2041	365	14.1	5.1	410.4	14.1	5.1	410.4	10.6	3.9	307.8	8.1	2.9	239.2
26	2042	365	12.6	4.6	415.0	12.6	4.6	415.0	9.5	3.5	311.2	7.3	2.7	241.9
27	2043	365	11.3	4.1	419.1	11.3	4.1	419.1	8.5	3.1	314.3	6.6	2.4	244.3
28	2044	366	10.1	3.7	422.8	10.1	3.7	422.8	7.6	2.8	317.1	6.0	2.2	246.5
29	2045	365	5.8	2.1	424.9	-	-	422.8	-	-	317.1	-	-	246.5
30	2046	365	3.3	1.2	426.1	-	-	422.8	-	-	317.1	-	-	246.5
31	2047	365	-	-	426.1	-	-	422.8	-	-	317.1	-	-	246.5
	Sub Total			426.1			422.8			317.1			246.5	
	Total			426.1			422.8			317.1			246.5	

Ntorya Total Contingent 1C Case

	Year	Production Days	TECHNICAL RESOURCES			FORECAST FUTURE FIELD PRODUCTION (AFTER ECONOMIC CUT OFF)								
			Gross Field Resources (100% Basis)			Gross Field Resources (100% Basis)			WI share of Gross Field Resources			Net Entitlement Resources		
			MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf
1	2017	365	-	-	-	-	-	-	-	-	-	-	-	-
2	2018	365	-	-	-	-	-	-	-	-	-	-	-	-
3	2019	365	-	-	-	-	-	-	-	-	-	-	-	-
4	2020	366	44.6	16.3	16.3	44.6	16.3	16.3	33.4	12.2	12.2	28.5	10.4	10.4
5	2021	365	103.7	37.8	54.2	103.7	37.8	54.2	77.8	28.4	40.6	64.7	23.6	34.1
6	2022	365	130.2	47.5	101.7	130.2	47.5	101.7	97.6	35.6	76.3	80.1	29.3	63.3
7	2023	365	130.2	47.5	149.2	130.2	47.5	149.2	97.7	35.6	111.9	80.1	29.3	92.6
8	2024	366	130.2	47.7	196.9	130.2	47.7	196.9	97.7	35.7	147.6	78.8	28.8	121.4
9	2025	365	129.0	47.1	243.9	129.0	47.1	243.9	96.7	35.3	183.0	63.8	23.3	144.7
10	2026	365	121.0	44.2	288.1	121.0	44.2	288.1	90.7	33.1	216.1	58.5	21.4	166.0
11	2027	365	112.8	41.2	329.3	112.8	41.2	329.3	84.6	30.9	247.0	53.9	19.7	185.7
12	2028	366	105.5	38.6	367.9	105.5	38.6	367.9	79.1	29.0	275.9	51.1	18.7	204.4
13	2029	365	99.0	36.1	404.0	99.0	36.1	404.0	74.2	27.1	303.0	48.6	17.7	222.2
14	2030	365	93.1	34.0	438.0	93.1	34.0	438.0	69.8	25.5	328.5	45.9	16.8	238.9
15	2031	365	87.8	32.0	470.0	87.8	32.0	470.0	65.8	24.0	352.5	43.5	15.9	254.8
16	2032	366	82.9	30.3	500.4	82.9	30.3	500.4	62.1	22.7	375.3	41.3	15.1	269.9
17	2033	365	78.3	28.6	529.0	78.3	28.6	529.0	58.7	21.4	396.7	39.3	14.3	284.2
18	2034	365	74.1	27.1	556.0	74.1	27.1	556.0	55.6	20.3	417.0	37.4	13.6	297.9
19	2035	365	70.2	25.6	581.6	70.2	25.6	581.6	52.7	19.2	436.2	35.6	13.0	310.9
20	2036	366	66.6	24.4	606.0	66.6	24.4	606.0	50.0	18.3	454.5	34.0	12.4	323.3
21	2037	365	63.3	23.1	629.1	63.3	23.1	629.1	47.4	17.3	471.8	32.4	11.8	335.1
22	2038	365	60.1	21.9	651.1	60.1	21.9	651.1	45.1	16.5	488.3	31.0	11.3	346.5
23	2039	365	57.2	20.9	672.0	57.2	20.9	672.0	42.9	15.7	504.0	29.7	10.8	357.3
24	2040	366	54.5	20.0	691.9	54.5	20.0	691.9	40.9	15.0	518.9	28.5	10.4	367.7
25	2041	365	52.0	19.0	710.9	52.0	19.0	710.9	39.0	14.2	533.2	27.3	10.0	377.7
26	2042	365	49.6	18.1	729.0	49.6	18.1	729.0	37.2	13.6	546.7	26.2	9.6	387.2
27	2043	365	47.3	17.3	746.2	47.3	17.3	746.2	35.5	12.9	559.7	25.0	9.1	396.4
28	2044	366	45.2	16.5	762.8	45.2	16.5	762.8	33.9	12.4	572.1	23.9	8.7	405.1
29	2045	365	43.2	15.8	778.5	-	-	762.8	-	-	572.1	-	-	405.1
30	2046	365	41.2	15.0	793.5	-	-	762.8	-	-	572.1	-	-	405.1
31	2047	365	-	-	793.5	-	-	762.8	-	-	572.1	-	-	405.1
	Sub Total			793.5			762.8			572.1			405.1	
	Total			793.5			762.8			572.1			405.1	

Ntorya Total Contingent 2C Case

			TECHNICAL RESOURCES			FORECAST FUTURE FIELD PRODUCTION (AFTER ECONOMIC CUT OFF)								
Year		Production Days	Gross Field Resources (100% Basis)			Gross Field Resources (100% Basis)			WI share of Gross Field Resources			Net Entitlement Resources		
			MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf	MMscf/d	Bscf	Cum. Bscf
1	2017	365	-	-	-	-	-	-	-	-	-	-	-	-
2	2018	365	-	-	-	-	-	-	-	-	-	-	-	-
3	2019	365	-	-	-	-	-	-	-	-	-	-	-	-
4	2020	366	52.6	19.2	19.2	52.6	19.2	19.2	39.4	14.4	14.4	33.6	12.3	12.3
5	2021	365	107.7	39.3	58.5	107.7	39.3	58.5	80.8	29.5	43.9	67.0	24.5	36.8
6	2022	365	133.0	48.5	107.1	133.0	48.5	107.1	99.7	36.4	80.3	81.8	29.8	66.6
7	2023	365	133.0	48.5	155.6	133.0	48.5	155.6	99.7	36.4	116.7	81.8	29.8	96.4
8	2024	366	133.0	48.7	204.3	133.0	48.7	204.3	99.7	36.5	153.2	76.8	28.1	124.5
9	2025	365	133.0	48.5	252.8	133.0	48.5	252.8	99.7	36.4	189.6	65.2	23.8	148.3
10	2026	365	133.0	48.5	301.4	133.0	48.5	301.4	99.7	36.4	226.0	62.9	23.0	171.3
11	2027	365	133.0	48.5	349.9	133.0	48.5	349.9	99.7	36.4	262.5	61.4	22.4	193.7
12	2028	366	133.0	48.7	398.6	133.0	48.7	398.6	99.7	36.5	299.0	61.3	22.4	216.1
13	2029	365	133.0	48.5	447.2	133.0	48.5	447.2	99.8	36.4	335.4	61.3	22.4	238.5
14	2030	365	131.7	48.1	495.2	131.7	48.1	495.2	98.8	36.1	371.4	60.7	22.2	260.7
15	2031	365	127.4	46.5	541.7	127.4	46.5	541.7	95.5	34.9	406.3	59.1	21.6	282.2
16	2032	366	123.1	45.1	586.8	123.1	45.1	586.8	92.3	33.8	440.1	57.4	21.0	303.3
17	2033	365	119.1	43.5	630.2	119.1	43.5	630.2	89.3	32.6	472.7	55.9	20.4	323.7
18	2034	365	115.2	42.1	672.3	115.2	42.1	672.3	86.4	31.5	504.2	54.4	19.9	343.5
19	2035	365	111.6	40.7	713.0	111.6	40.7	713.0	83.7	30.5	534.8	53.0	19.4	362.9
20	2036	366	108.1	39.6	752.6	108.1	39.6	752.6	81.1	29.7	564.5	51.7	18.9	381.8
21	2037	365	104.8	38.3	790.9	104.8	38.3	790.9	78.6	28.7	593.2	50.5	18.4	400.2
22	2038	365	101.8	37.1	828.0	101.8	37.1	828.0	76.3	27.9	621.0	49.3	18.0	418.2
23	2039	365	98.8	36.1	864.1	98.8	36.1	864.1	74.1	27.1	648.1	48.1	17.5	435.8
24	2040	366	96.0	35.1	899.3	96.0	35.1	899.3	72.0	26.4	674.4	46.8	17.1	452.9
25	2041	365	93.3	34.1	933.3	93.3	34.1	933.3	70.0	25.6	700.0	45.6	16.6	469.5
26	2042	365	90.8	33.1	966.5	90.8	33.1	966.5	68.1	24.8	724.8	44.4	16.2	485.8
27	2043	365	88.3	32.2	998.7	88.3	32.2	998.7	66.2	24.2	749.0	43.3	15.8	501.6
28	2044	366	85.9	31.4	1,030.1	85.9	31.4	1,030.1	64.4	23.6	772.6	42.2	15.5	517.0
29	2045	365	83.6	30.5	1,060.7	-	-	1,030.1	-	-	772.6	-	-	517.0
30	2046	365	81.2	29.6	1,090.3	-	-	1,030.1	-	-	772.6	-	-	517.0
31	2047	365	-	-	1,090.3	-	-	1,030.1	-	-	772.6	-	-	517.0
Sub Total				1,090.3			1,030.1			772.6			517.0	
Total				1090.3			1030.1			772.6			517.0	

Ntorya Total Contingent 3C Case

PART VIII

DEFINITIONS

"**2016 Prospectus**"	means the 8 July 2016 Prospectus issued by Aminex;
"**API**"	means American Petroleum Institute;
"**APT**"	means ARA Petroleum Tanzania Limited, a company existing under the laws of Tanzania with registered number 138250296;
"**Aminex**" or the "**Company**"	means Aminex public limited company, a company registered in Ireland with registered number 72399 and having its registered office at 6 Northbrook Road, Dublin 6, Ireland;
"**Aminex Group**" or "**the Group**"	means Aminex and its subsidiaries, subsidiary undertakings and associate undertakings;
"**Articles**" or "**Articles of Association**"	means the articles of association of the Company, as amended from time to time;
"**Assigned Interest**"	means a fifty per cent. undivided Participating Interest in and under the Ruvuma PSA and the JOA, together with all of the rights, benefits, interests and Liabilities attaching thereto;
"**Board**"	means the board of directors of Aminex;
"**Business Day(s)**"	means a day/days (not being a Saturday or Sunday) on which banks are open for normal banking business in London, UK and Dublin, Ireland;
"**Carry**"	means the payment by the Farmee of Ndovu's Participating Interest share of the charges, costs, expenses or Liabilities incurred or arising under the Ruvuma PSA, the JOA or any other document including, without limitation, Ndovu's Participating Interest share of the charges, costs, expenses and Liabilities arising in respect of the Carry Work Programme. The amount of money that the Farmee undertakes to spend in discharging this shall be capped at US$35 million;
"**Carry Work Programme**"	means the following agreed work programme: • the drilling, completion and testing of the proposed Chikumbi-1 well as early as possible • the establishment of an early production system as soon as possible • the acquisition, processing and interpretation of at least 200km^2 of 3D seismic over the Ntorya area • the generation of a field development plan to allow for the full field final investment decision;
"**Cash Consideration**"	means the cash consideration of US$3 million payable by the Farmee to Ndovu at Completion and the deferred cash payment of US$2 million payable by the Farmee to Ndovu 180 calendar days after the date of Completion;
"**Central Bank**"	means the Central Bank of Ireland;
"**Chance of Development**"	means the chance that the known accumulation will, once discovered, be commercially developed;

"**Chance of Geological Discovery**"	means the likelihood of source rock, charge, reservoir, trap and seal combining to result in a present-day hydrocarbon accumulation;
"**Circular**"	means this document, dated 7 December 2018 in respect of the EGM posted to holders of Ordinary Shares and, for information only, to the Option Holders;
"**Companies Act**"	means the Companies Act 2014, as amended;
"**Computershare Investor Services**"	means Computershare Investor Services (Ireland) Limited, the Company's registrar;
"**Competent Person**"	means RPS Energy Consultants Limited;
"**Completion**"	means the completion of the Transaction in accordance with the terms and conditions of the Farm-Out Agreement;
"**Cost Gas**"	means all exploration expenses, development expenses, operating expenses, service costs and general and administrative costs recovered from a volume of natural gas produced under the Ruvuma PSA. Such fiscal terms for the production of gas are currently being negotiated with the Tanzanian authorities and expected to form part of an amended Ruvuma PSA;
"**CPI**"	means consumer price index;
"**CREST**"	means the relevant system (as defined in the CREST Regulations), as amended enabling title to securities to be evidenced and transferred in dematerialised form operated by Euroclear;
"**CREST member**"	means a person who has been admitted by Euroclear as a system-member (as defined in the 1996 Regulations);
"**CREST Regulations**"	means the Companies Act 1990 (Uncertificated Securities) Regulations 1996, including (i) any enactment or subordinate legislation which amends or supersedes those regulations and (ii) any applicable rules made under those regulations or any such enactment or subordinate legislation for the time being in force;
"**CREST Shareholders**"	means Shareholders holding Ordinary Shares in uncertificated form;
"**CREST sponsor**"	means a CREST participant admitted to CREST as a CREST sponsor;
"**CREST sponsored member**"	means a CREST member admitted to CREST as a sponsored member (which includes all CREST personal members);
"**Davy**"	means J&E Davy, trading as Davy or, as the context so requires, any affiliate thereof or company within its group;
"**Disclosure Guidance and Transparency Rules**"	means the disclosure and transparency rules made by the FCA pursuant to Part 6 of FSMA;
"**Directors**"	means the directors of Aminex;
"**East African Margin**"	means principally Kenya, Tanzania, Mozambique and Madagascar;

“**Eclipse**”	means Eclipse Investments LLC, a company incorporated and registered in the United Arab Emirates with commercial registration number 77990 whose registered office is at P.O. Box 60808, Bur Dubai, United Arab Emirates;
“**EGM**” or “**Extraordinary General Meeting**”	means the extraordinary general meeting of the Company, notice of which is set out at the end of this Circular, to be held at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul’s Churchyard, London, EC4M 8AL, United Kingdom at 12.30 p.m. on 4 January 2019 or any adjournment thereof;
“**Effective Date**”	means from the start of the day (Tanzanian time) on 15 March 2018;
“**EU**”	means the European Union;
“**EUR**” or “**€**”	means euro, the lawful currency of Ireland;
“**Euroclear**”	means Euroclear UK & Ireland Limited, the operator of CREST;
“**Euronext Dublin**”	means the Irish Stock Exchange plc, trading as Euronext Dublin;
“**Executive Directors**”	means Jay Bhattacherjee and Max Williams;
“**Existing Ordinary Shares**”	means the 3,643,458,062 Ordinary Shares in issue at the Latest Practicable Date;
“**Farm-Out Agreement**”	means the farmout agreement between Ndovu, Aminex and Zubair dated 11 July 2018, as the same may be amended from time to time;
“**Farmee**”	means Zubair or APT;
“**FCA**”	means the Financial Conduct Authority of the United Kingdom;
“**FCA Handbook**”	means the handbook of rules and guidance issued by the FCA under the FSMA, as amended from time to time;
“**FSMA**”	means the Financial Services and Markets Act 2000 of the United Kingdom;
“**Gas Sales Agreement**”	means the gas sales agreement in respect of gas produced from the Kiliwani North-1 well between the TPDC, Ndovu Resources Limited and other joint venture partners of the Kiliwani North Development Licence dated 31 December 2015;
“**Group**”	means the Company and its subsidiary undertakings;
“**Indemnity**”	means the unlimited indemnity given by the Company in favour of Zubair under the terms of the Farm-Out Agreement;
“**Ireland**”	means Ireland other than Northern Ireland;
“**ISIN**”	means International Securities Identification Number;
“**JOA**”	means the Joint Operating Agreement between Hardman Resources Limited and Ndovu Resources Limited dated 23 March 2006, as amended from time to time;
“**Kiliwani North**”	means an oil and gas discovery well drilled from Songo-Songo Island drilled under the Nyuni East Songo Songo PSA;
“**Kiliwani North Development Licence**”	means the Company’s licence for a 25-year term from April 2011 under which Aminex is permitted to expedite the development, construction and tie-in of Kiliwani North;

"**Latest Practicable Date**"	means 6 December 2018 being the latest practicable date prior to the publication of this Circular;
"**Lindi Licence**"	means an exploration licence applied for by the TPDC under the Contract in respect of the Lindi area and any extensions, amendments or replacements thereto;
"**Liabilities**"	means all liabilities, duties, obligations, damage, loss, compensation, award, cost, expense, charge, fine or penalty howsoever incurred;
"**Listing Rules**"	means the listing rules issued by the FCA in its capacity as the competent authority for the purposes of Part VI of FSMA and as set out in the FCA Handbook as amended from time to time and/or the listing rules issued by the Euronext Dublin;
"**London Stock Exchange**"	means the London Stock Exchange plc;
"**Madimba Gas Processing Plant**"	means the TPDC Madimba Gas Processing Plant at Msimbati, Tanzania;
"**Market Abuse Regulations**"	means European Union (Market Abuse) Regulations 2016;
"**Memorandum**"	means the memorandum of association of the Company;
"**Mtwara Licence**"	means an exploration licence applied for by the TPDC under the Contract in respect of the Mtwara area and any extensions, amendments or replacements thereto;
"**Ndovu**"	means Ndovu Resources Limited, a company existing under the laws of Tanzania with registered number 35152;
"**Non-CREST Shareholders**"	means shareholders who are not CREST Shareholders;
"**Non-executive Directors**"	means the Directors other than the Executive Directors;
"**Ntorya Blocks**"	means the nine graticular blocks within the Mtwara Licence under the terms of the Ruvuma PSA, which comprise the Ntorya location and for which a development licence application has been submitted;
"**Ntorya Development Licence**"	means the proposed development licence for the Ntorya Field, an application for which was made in September 2017 and is pending approval;
"**Ntorya Field**"	means the hydrocarbon bearing field of that name contained within the Ntorya Blocks;
"**Nyuni Area**"	means an area of approximately 845 sq. km offshore Tanzania over which Aminex and its joint venture partners have exploration rights;
"**Nyuni Area PSA**"	means the Nyuni Area production sharing agreement;
"**Nyuni East Songo Songo PSA**"	means the Nyuni East Songo Songo production sharing agreement which governs the Kiliwani North Development Licence;
"**Official Lists**"	means the official lists of the UKLA and the Euronext Dublin;
"**Options**"	means options to subscribe for Ordinary Shares pursuant to the Share Option Scheme;
"**Option Holders**"	means the holders of Options under the Share Option Scheme;

"**Ordinary Shares**"	means ordinary shares of €0.001 each in the capital of the Company;
"**Participating Interest**"	means in respect of any party to the Ruvuma PSA, the undivided interest of such party expressed as a percentage of the total interests of all parties in the rights and obligations derived from the Ruvuma PSA and the JOA;
"**PRMS**"	means the classification system set out in the Petroleum Resources Management System published in 2018 and jointly sponsored by the Society of Petroleum Engineers (SPE), the American Association of Petroleum Geologists (AAPG), the World Petroleum Council (WPC), the Society of Petroleum Evaluation Engineers (SPEE), the Society of Exploration Geophysicists (SEG), the Society of Petrophysicists and Well Log Analysts (SPWLA) and the European Association of Geoscientists & Engineers (EAGE);
"**Prospectus Rules**"	means the Prospectus Rules of the Central Bank issued under section 51 of the 2005 Act;
"**Profit Gas**"	means the balance of natural gas available in any year after deduction of Cost Gas and allocated in accordance with the Ruvuma PSA. Such fiscal terms for the production of gas are currently being negotiated with the Tanzanian authorities and expected to form part of an amended Ruvuma PSA;
"**Regulatory Information Service**" or "**RIS**"	one of the regulatory information services authorised by the Euronext Dublin and/or the FCA to receive, process and disseminate regulated information from listed companies;
"**Registrar**"	means Computershare Investor Services;
"**Relationship Agreement**"	means the agreement dated 8 July 2016 between the Company and Eclipse regulating the relationship between them and governing the exercise by Eclipse of its rights in respect of the Company (a summary of which is incorporated by reference to the 2016 Prospectus);
"**Resolution**"	means the resolution to be proposed at the Extraordinary General Meeting as set out in the Circular;
"**RPS Energy**"	means RPS Energy Consultants Limited, a company existing under the laws of England with registered number 03287074;
"**RPS Report**"	means the Technical Report;
"**Ruvuma Area**"	means an area of approximately 1,682 sq. km. onshore Tanzania over which Aminex and its joint venture partners have exploration rights;
"**Ruvuma PSA**"	means the Ruvuma production sharing agreement over the Mtwara Licence, including the Ntorya Blocks;
"**Ruvuma PSA Addendum**"	means the addendum to the Ruvuma PSA entered into between the Tanzanian Government, TPDC and Ndovu, dated 28 January 2014, pursuant to which Ndovu agreed to grant security to the Government and TPDC over Ndovu's interests in the Kiliwani North Development Licence;
"**Share Option Scheme**"	means the Aminex PLC Executive Share Option Scheme adopted by the Company on 10 May 1980;
"**Shareholders**"	means holders of Ordinary Shares apart from Eclipse;

"**Deed of Amendment**"	means the deed of amendment to the Farm-Out Agreement dated 21 November 2018 between Ndovu, Aminex and Zubair, extending the long stop date for Completion from 30 November 2018 to 31 March 2019.
"**Solo Oil**"	means Solo Oil plc, a company registered in England and Wales with registered number 05542880 and having its registered office at Suite 3B, Princes House, Jermyn Street, London, SW1Y 6DN;
"**Songo-Songo**"	means the name of a small island, off the coast of Tanzania, where natural gas was discovered in 1974. The Songo-Songo gas field was first developed by the Tanzanian government from 1974 to the mid-1980s;
"**stock account**"	means an account within a member account in CREST to which a holding of a particular share or other security in CREST is credited;
"**Stock Exchanges**"	means the Euronext Dublin and the London Stock Exchange;
"**subsidiary**"	shall be construed in accordance with the Companies Act;
"**subsidiary undertakings**"	shall have the meaning given by the European Communities (Companies: Group Accounts) Regulations 1992;
"**Tanzanian Government**"	means the government of the United Republic of Tanzania and any political subdivision, agency or instrumentality thereof, including the government national oil and gas company, TPDC;
"**Technical Report**"	means the mineral experts' report prepared by the Competent Person setting out the statement of reserve data and other oil and gas information in respect of the assets of the Ruvuma PSA, dated 4 December 2018, prepared in accordance with the PRMS and reproduced in its entirety at Part VII of this Circular;
"**Transparency Regulations and Rules**"	means the Transparency (Directive 2004/109/EC) Regulations 2007 and the Transparency Rules of the Central Bank issued under section 22 of the 2006 Act, as amended from time to time;
"**Transaction**"	means the proposed disposal of 50 per cent. interest in the Ruvuma PSA subject to the terms and conditions of the Farm-Out Agreement and the Deed of Amendment;
"**TPDC**"	means the Tanzania Petroleum Development Corporation
"''**uncertificated**'' or in ''**uncertificated form**"	means the Ordinary Shares recorded on the register of members of the Company as being held in uncertificated form in CREST and title to which, by virtue of the CREST Regulations, may be transferred by means of an instruction issued in accordance with the rules of CREST;
"**UK Listing Authority**" or "**UKLA**"	means the UK Listing Authority, being the FCA acting in its capacity as the competent authority for the purposes of Part VI of the FSMA;
"**US**", "**USA**" or "**United States**"	means the United States of America, its territories and possessions, any state of the United States of America, the District of Columbia and all other areas subject to the jurisdiction of the United States of America; and
"Voting Share Capital"	means the Ordinary Shares of the Company available to be voted at the EGM, being 3,643,458,062 Ordinary Shares in issue less the number of shares held by Eclipse;

"**Zubair**"	means The Zubair Corporation LLC, a company existing under the laws of Sultanate of Oman with registered number 1000012; and
"**The Zubair Corporation**"	means the group of companies controlled by the Al Zubair family.

PART IX

GLOSSARY

The following are definitions of certain terms that are commonly used in the oil and gas industry and in this Circular.

Certain Terminology

appraisal	the phase of petroleum operations immediately following a successful discovery. Appraisal is carried out to determine size, production rate and the most efficient development of a field;
appraisal well	a well drilled as part of an appraisal of a field;
2D seismic	geophysical data that depicts the subsurface strata in two dimensions;
3D seismic	3D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2D seismic;
barrel or bbl	a stock tank barrel, a standard measure of volume for oil, condensate and natural gas liquids, which equals 42 US gallons;
bcf	billion cubic feet;
behind-pipe reserves	reserves which are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production;
block	term commonly used to describe areas over which there is a petroleum or production licence or PSC or PSA;
boed	barrels of oil equivalent per day;
bopd	barrels of oil per day;
commercial discovery	discovery of oil and gas which the Company determines to be commercially viable for appraisal and development;
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;
deepwater	any area of water over 250 metres in depth;
discovery	an exploration well which has encountered oil and gas for the first time in a structure;
exploration	the phase of operations which covers the search for oil or gas by carrying out detailed geological and geophysical surveys followed up where appropriate by exploratory drilling;
exploration drilling	drilling carried out to determine whether oil and gas are present in a particular area or structure;
exploration well	a well in an unproven area or prospect, may also be known as a “wildcat well”;
farm out	a term used to describe when a company sells a portion of the acreage in a block to another company, usually in return for

	consideration and for the buying company taking on a portion of the selling company's work commitments;
field	an area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition;
gas condensate	the heavier hydrocarbon fractions in a natural gas reservoir that condense into a liquid as they are produced. They are used as a chemical feedstock or for blending into gasoline;
Gas Initially in Place or GIIP	means the total gas content of a reservoir before the start of production;
hydrocarbons	compounds formed primarily from the elements hydrogen (H) and carbon (C) and existing in solid, liquid or gaseous forms;
km	kilometre;
lower Cretaceous	lower of the two major divisions of the Cretaceous;
licence	an exclusive right to explore for petroleum, usually granted by a national governing body;
mmcfd	million cubic feet per day;
mmscf/d	million standard cubic feet per day;
natural gas	hydrocarbons that are gaseous at one atmosphere of pressure at 15.56°C. It can be divided into lean gas, primarily methane but often containing some ethane and smaller quantities of heavier hydrocarbons and wet gas, primarily ethane, propane and butane as well as smaller amounts of heavier hydrocarbons;
offshore	a geographic area that lies seaward of the coastline;
oil field	the mapped distribution of a proven oil-bearing reservoir or reservoirs;
onshore	a geographic area that lies landward of the coastline;
operator	the company that has legal authority to drill wells and undertake production of oil and gas. The operator is often part of a consortium and acts on behalf of this consortium;
play	a conceptual model for a style of hydrocarbon accumulation;
P.mean	means the mean or average value of the probability distribution representing the best estimate of undiscovered oil or gas initially in place;
prospects	exploration targets which are well defined and are ready to be drilled or close to it;
prospective resources	those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from undiscovered accumulations;
prospectivity	the likelihood of an area to contain potential hydrocarbon accumulations, i.e. prospects;
proved reserves	reserves which, based on the available evidence and taking into account technical and economic factors, have at least a 90 per cent. chance of being produced;

PSA or PSC	production sharing agreement or contract under which the contractor agrees to fund and carry out pre-agreed work programmes on behalf of the concession owner in return for a share of production revenues;
reserves	those quantities of petroleum which are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reference should be made to the full PRMS definitions for the complete definitions and guidelines;
reservoir	a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. A reservoir is a critical component of a complete petroleum system;
resources	contingent and prospective resources, unless otherwise specified;
rig	the machine used to drill a wellbore;
seismic survey	a method by which an image of the earth's subsurface is created through the generation of shockwaves and analysis of their reflection from rock strata. Such surveys can be done in two-or three-dimensional form;
spud	to commence the well drilling process by removing rock, dirt and other sedimentary material with a drill;
TCF	trillion cubic feet;
upstream	activities related to the exploration, appraisal, development and extraction of crude oil, condensate and gas; and
workover	a maintenance or repair operation on a well after it has commenced production. Usually undertaken to maintain or increase production from the well.

NOTICE OF EXTRAORDINARY GENERAL MEETING

Aminex PLC

(Incorporated and registered in Ireland under the Companies Act 2014 with registered number 72399)

NOTICE OF GENERAL MEETING

NOTICE IS HEREBY GIVEN that a **GENERAL MEETING** of Aminex PLC (the "**Company**") will be held at 12.30 p.m. on 4 January 2019 at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul's Churchyard, London, EC4M 8AL, United Kingdom for the purpose of considering and, if thought fit, passing the following resolution as an ordinary resolution of the Company:

ORDINARY RESOLUTION

(a) That the proposed sale of 50 per cent. interest in the Ruvuma PSA as described in the circular to Shareholders dated 7 December 2018, pursuant to the terms and subject to the conditions of the Farm-Out Agreement entered into 11 July 2018 and the Deed of Amendment entered into on 21 November 2018, being a Class 1 transaction and related party transaction for the purposes of the Listing Rules, be and is hereby approved with any changes as are permitted in accordance with (c) below; and

(b) that the Indemnity given by the Company in favour of Zubair pursuant to the Farm-Out Agreement be and is hereby approved with any changes as are permitted in accordance with (c) below; and

(c) the Directors (or a committee of the Directors) be and are hereby generally and unconditionally authorised to do all such acts and things as they may in their absolute discretion consider necessary and/or desirable in order to implement and complete the Transaction in accordance with the terms described in the Farm-Out Agreement and the Deed of Amendment, subject to such immaterial amendments or variations thereto as the Directors (or a committee of the Directors) may in their absolute discretion think fit.

DATED 7 December 2018

BY ORDER OF THE BOARD

BRIAN CASSIDY

COMPANY SECRETARY

REGISTERED OFFICE: 6 NORTHBROOK ROAD, DUBLIN 6.

REGISTERED IN DUBLIN, IRELAND – NO. 72399

Notes:

Entitlement to attend and vote

(1) Every member, irrespective of how many Aminex shares they hold, has the right to attend, speak, and vote at the EGM. Completion of a form of proxy will not affect your right to attend, speak and vote at the EGM in person. The right to participate in the EGM is subject to the registration of the shares on the EGM Record Date (defined at note 2 below).

Record Date for EGM

(2) In accordance with Section 1095 of the Companies Act 2014 and Regulation 14 of the Companies Act, 1990 (Uncertificated Securities) Regulations, 1996 (as amended), the Company specifies that only those Shareholders registered in the register of members of the Company as at the close of business on the day which is two days prior to the EGM ("**EGM Record Date**") (or in the case of an adjournment as at 12.30 p.m. on the day which is two days before the time appointed for the holding of the adjourned meeting) shall be entitled to attend and vote at the meeting in respect of the number of shares registered in their names at the time. Changes in the register after that time will be disregarded in determining the right of any person to attend and/or vote at the meeting.

Website giving information regarding the meeting

(3) This EGM notice, details of the total number of shares and voting rights at the date of giving this notice, the documents to be submitted to the meeting, copies of any draft resolutions and copies of the forms to be used to vote by proxy are available on the Company's website at www.aminex-plc.com.

Attending in person

(4) The Extraordinary General Meeting will be held at Shepherd and Wedderburn LLP, Condor House, 10 St. Paul's Churchyard, London, EC4M 8AL, United Kingdom, on 4 January 2019 at 12.30 p.m.. If you wish to attend the Extraordinary General Meeting in person, you are recommended to attend at least 15 minutes before the time appointed for holding of the Extraordinary General Meeting to allow time for registration. Please bring the attendance card attached to your Form of Proxy and present it at the shareholder registration desk before the commencement of the Extraordinary General Meeting.

Appointment of proxies

(5) A member entitled to attend, speak and vote at the above meeting is entitled to appoint a proxy to attend, speak and vote in his/her behalf. A member may appoint more than one proxy to attend and vote at the Extraordinary General Meeting in respect of shares held in different securities accounts. A member acting as an intermediary on behalf of one or more clients may grant a proxy to each of its clients or their nominees provided each proxy is appointed to exercise rights attached to different shares held by that member. A proxy need not be a member of the Company.

(6) A Form of Proxy for use by members is enclosed with this Notice of Extraordinary General Meeting (or is otherwise being delivered to Shareholders). Completion of a Form of Proxy (or submission of proxy instructions electronically) will not prevent a shareholder from attending the Extraordinary General Meeting and voting in person should they wish to do so.

(7) To be valid, the Form of Proxy must be delivered to Computershare Investor Services (Ireland) Limited, PO Box 954, Sandyford, Dublin 18, Ireland (if delivered by post) or at Heron House, Corrig Road, Sandyford Industrial Estate, Dublin 18, Ireland (if delivered by hand) as soon as possible and, in any event, so as to be received not less than forty-eight hours before the time for the holding of the meeting, or any adjournment thereof.

(8) CREST members who wish to appoint a proxy or proxies by utilising the CREST electronic proxy appointment service may do so for the Extraordinary General Meeting and any adjournment(s) thereof by utilising the procedures described in the CREST Manual. 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 appropriate action on their behalf.

(9) In order for a proxy appointment made by means of CREST to be valid, the appropriate CREST message (a "CREST Proxy Instruction") must be properly authenticated in accordance with Euroclear's specifications and must contain the information required for such instructions, as described in the CREST Manual. The message (whether it constitutes the appointment of a proxy or an amendment to the instruction given to a previously appointed proxy) must be transmitted so as to be received by Computershare Investor Services (Ireland) Limited, as issuer's agent, (ID 3RA50) by the latest time(s) for receipt of proxy appointments specified in this notice of 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 Applications Host) from which the issuers agent is able to retrieve the message by enquiry to CREST in the manner prescribed by CREST.

(10) CREST members and, where applicable, their CREST sponsors or voting service providers should note that Euroclear UK & Ireland Limited does not make available special procedures in CREST for any particular messages. 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 his CREST sponsor or voting service provider(s) take(s) such action as shall be necessary to ensure that a message is transmitted by the CREST system by any particular time. In this connection, CREST members and, where applicable, their CREST sponsors or voting service providers are referred, in particular, to those sections of the CREST Manual concerning practical limitations of the CREST system and timings.

(11) The Company may treat as invalid a CREST Proxy Instruction in the circumstances set out in Regulation 35(5)(a) of the Companies Act 1990 (Uncertificated Securities) Regulations 1996.

(12) In case of a corporation, the instrument shall be either under its common seal or under the hand of an officer or attorney duly authorised in that behalf.

(13) In the case of joint holders, the vote of the senior who tenders a vote, whether in person or by proxy, will be accepted to the exclusion of the votes of the other registered holder(s) and for this purpose, seniority will be accepted to order in which the names stand in the register of members of the Company in respect of a joint holding.

(14) If a proxy is executed under a power of attorney, such power of attorney must be deposited with the Company with the Form of Proxy.

Action to be taken

(15) Electronic proxy appointment is available for the Extraordinary General Meeting. This facility enables a Shareholder to lodge its proxy appointment by electronic means by logging on to the website of the Registrars, www.eproxyappointment.com. You will need the Control Number, your shareholder reference number and your PIN number, which can be found on your Form of Proxy. Alternatively, for those who hold Ordinary Shares in CREST, a Shareholder may appoint a proxy in accordance with the instructions at note 8 above. In each case the proxy appointment must be received by no later than 12.30 p.m., 2 January 2019.

Issued shares and total voting rights

(16) The total number of issued shares on the date of this notice of Extraordinary General Meeting is 3,643,458,062. On a vote by show of hands every shareholder who is present in person and every proxy has one vote (but no individual shall have more than one vote). On a poll every shareholder shall have one vote for every share carrying voting rights of which he is the holder.

The ordinary resolution requires a simple majority of shareholders voting in person or by proxy to be passed.

Questions at the Extraordinary General Meeting

(17) Under Section 1107 of the Companies Act, the Company must answer any question you ask relating to the business being dealt with at the Extraordinary General Meeting unless:

(i) answering the question would interfere unduly with the preparation for the Extraordinary General Meeting or the confidentiality and business interests of the Company;

(ii) the answer has already been given on a website in the form of an answer to a question; or

(iii) it appears to the Chairman of the Extraordinary General Meeting that it is undesirable in the interests of good order of the meeting that the question be answered.

Shareholders' right to table draft resolutions

(18) Pursuant to Section 1104 of the Companies Act, if you or a group of members hold at least 3% of the issued share capital of the Company, you or the group of members acting together have the right to table a draft resolution for inclusion in the agenda of the EGM subject to any contrary provision in company law. In order to exercise this right, the text of the draft resolution and evidence of your shareholding must be received by post by the Company Secretary at Aminex PLC, 6 Northbrook Road, Dublin 6 or by email to company.secretary@aminex-plc.com within sufficient time so that it may be dispatched by the Company within the minimum notice period required for the resolution by the Companies Act. A resolution cannot be included in the EGM agenda unless it is received at either of these addresses by this deadline. Furthermore, members are reminded that there are provisions in company law that impose other conditions on the right of members to propose resolutions at the general meeting of a company.

Data Protection Statement

(19) Your personal data includes all data provided by you, or on your behalf, which relates to you as a shareholder, including your name and contact details, the votes you cast and your Shareholder Reference Number (attributed to you by the Company). The Company determines the purposes for which and the manner in which your personal data is to be processed. The Company and any third party to whom it discloses the data (including the Company's Registrars) may process your personal data for the purposes of compiling and updating the Company's records, fulfilling its legal obligations and processing the shareholder rights you exercise.

Display Documents

(20) The display documents are available for inspection in physical form during normal business hours on any weekday (Saturdays, Sundays and public holidays excepted) at the offices of ByrneWallace at 88 Harcourt Street, Dublin 2, Ireland, from the date of this Circular up to and including 4 January 2019, being the date of the Extraordinary General Meeting.