PETRONOR E&P ASA

(A public limited liability company incorporated under the laws of Norway)

Admission to listing and trading of the Company's 1,326,991,006 Shares on Oslo Børs in connection with the Group's re-domicile from Australia to Norway

This prospectus (the "**Prospectus**") has been prepared in connection with the admission to listing and trading (the "**Listing**" or "**Admission to Listing**") of 1,326,991,006 shares in PetroNor E&P ASA (the "**Company**"), a public limited liability company incorporated under the laws of Norway (together with its consolidated subsidiaries, the "**Group**" or "**PetroNor**"), each with a nominal value of NOK 0.001 (the "**Shares**") on Oslo Børs, a stock exchange operated by Oslo Børs ASA (the "**Oslo Stock Exchange**") in connection with the Group's re-domicile from Australia to Norway (the "**Redomiciliation**").

The Shares are registered in the Norwegian Central Securities Depository (the "**VPS**") in book-entry form. All Shares rank in parity with one another and carry one vote.

Investing in the Shares involves a high degree of risk. Prospective investors should read the entire Prospectus and, in particular, consider Section 2 "Risk Factors" when considering an investment in the Company.

The Shares have not been, and will not be, registered under the U.S. Securities Act or with any securities regulatory authority of any state or other jurisdiction in the United States, and are being offered and sold: (i) in the United States only to persons who are QIBs in reliance on Rule 144A or another available exemption from registration requirements of the Securities Act; and (ii) outside the United States in offshore transactions in compliance with Regulation S. Prospective investors are hereby notified that any seller of the Shares may be relying on the exemption from the provisions of Section 5 of the U.S. Securities Act provided by Rule 144A. The distribution of this Prospectus and the sale of the Shares may be restricted by law in certain jurisdictions. Accordingly, neither this Prospectus nor any advertisement or any other Listing material may be distributed or published in any jurisdiction, except under circumstances which will result in compliance with applicable laws and regulations. Persons in possession of this Prospectus are required by the Company to inform themselves about and to observe any such restrictions. Any failure to comply with these regulations may constitute a violation of the securities laws of any such jurisdictions.

Prior to the Admission to Trading, the shares (in the form of depository receipts) (the "**Australian Shares**") of PetroNor Australia E&P Ltd. ("**PetroNor Australia**") were tradeable on Euronext Expand, being a regulated market place. In connection with the Redomiciliation, holders of Australian Shares will receive 1 Share in the Company for each Depositary Receipt held in PetroNor Australia (the "**Share Swap**"). As part of the Redomiciliation, the Australian Shares will be delisted from Euronext Expand in conjunction with the the Admission to Listing. The capital increase in relation to the Share Swap was registered by the Company with the Norwegian Register of Business Enterprises on 24 February 2022.

The Shares will be eligible for clearing through the facilities of Oslo Børs.

Trading in the Shares on Oslo Børs is expected to commence on or about 28 February 2022, under the ticker code "PNOR".

The date of this Prospectus is 25 February 2022

IMPORTANT INFORMATION

This Prospectus has been prepared solely for use in connection with the Listing of the Shares on Oslo Børs. Please see Section 18 "Definitions" for definitions of terms used throughout this Prospectus.

This Prospectus has been prepared to comply with the Norwegian Securities Trading Act of 29 June 2007 no. 75, as amended (the "**Norwegian Securities Trading Act**") and related secondary legislation, including Regulation (EU) 2017/1129 of the European Parliament and of the Council of 14 June 2017 on the prospectus to be published when securities are offered to the public or admitted to trading on a regulated market, and repealing Directive 2003/71/EC, as amended, and as implemented in Norway in accordance with Section 7-1 of the Norwegian Securities Trading Act (the "**EU Prospectus Regulation**"). This Prospectus has been prepared solely in the English language. This Prospectus has been approved by the Financial Supervisory Authority of Norway (Nw: Finanstilsynet) (the "**Norwegian FSA**" or "**NFSA**"), as competent authority under the EU Prospectus Regulation. The Norwegian FSA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by the EU Prospectus Regulation, and such approval should not be considered as an endorsement of the issuer or the quality of the securities that are the subject of this Prospectus. Investors should make their own assessment as to the suitability of investing in the securities.

No person is authorised to give information or to make any representation concerning the Company or in connection with the Listing other than as contained in this Prospectus. If any such information is given or made, it must not be relied upon as having been authorised by the Company or by any of their affiliates.

The distribution of this Prospectus may be restricted by law in certain jurisdictions. This Prospectus does not constitute an offer of, or an invitation to purchase, any of the Shares in any jurisdiction in which such offer or sale would be unlawful. No one has taken any action that would permit a public offering of the Shares to occur outside of Norway. Accordingly, neither this Prospectus nor any advertisement or any other offering material may be distributed or published in any jurisdiction except as permitted by applicable laws and regulations. Persons in possession of this Prospectus are required to inform themselves about, and to observe, any such restrictions. In addition, the Shares are subject to restrictions on transferability and resale in certain jurisdictions and may not be transferred or resold except as permitted under applicable securities laws and regulations. Any failure to comply with these restrictions may constitute a violation of applicable securities laws.

The information contained herein is current as at the date hereof and subject to change, completion and amendment without notice. In accordance with Article 23 of the EU Prospectus Regulation, significant new factors, material mistakes or material inaccuracies relating to the information included in this Prospectus, which may affect the assessment of the Shares and which arises or is noted between the time when the Prospectus is approved by the Norwegian FSA and the listing of the Shares on Oslo Børs, will be mentioned in a supplement to this Prospectus without undue delay. Neither the publication nor distribution of this Prospectus, nor the sale of any Offer Share, shall under any circumstances imply that there has been no change in the Group's affairs or that the information herein is correct as of any date subsequent to the date of this Prospectus.

Investing in the Company involves a high degree of risk. See Section 2 "Risk Factors".

In making an investment decision, prospective investors must rely on their own examination, and analysis of, and enquiry into the Group, including the merits and risks involved. Neither the Company or any of their respective affiliates, representatives, advisers or selling agents, are making any representation to any offeree or purchaser of the Shares regarding the legality or suitability of an investment in the Shares. Each investor should consult with his or her own advisers as to the legal, tax, business, financial and related aspects of a purchase of the Shares.

This Prospectus is governed by Norwegian law. The courts of Norway, with Oslo as legal venue, have exclusive jurisdiction to settle any dispute which may arise out of or in connection with the Listing or this Prospectus.

All Sections of the Prospectus should be read in context with the information included in Section 4 "General Information".

ENFORCEMENT OF CIVIL LIABILITIES

The Company is a public limited liability company incorporated under the laws of Norway. As a result, the rights of holders of the Shares will be governed by Norwegian law and the Company's articles of association (the "**Articles of Association**"). The rights of shareholders under Norwegian law may differ from the rights of shareholders of companies incorporated in other jurisdictions. The members of the Company's board of directors (the "**Board Members**" and the "**Board of Directors**", respectively) and the members of the senior management of the Company (the "**Management**") are not residents of the United States. Virtually all of the Company's assets and the assets of the Board Members and members of Management are located outside the United States. As a result, it may be impossible or difficult for investors in the United States to effect service of process upon the Company, the Board Members and members of Management in the United States or to enforce against the Company or those persons judgments obtained in U.S. courts, whether predicated upon civil liability provisions of the federal securities laws or other laws of the United States.

The United States and Norway do not currently have a treaty providing for reciprocal recognition and enforcement of judgements (other than arbitral awards) in civil and commercial matters. Uncertainty exists as to whether courts in Norway will enforce judgments obtained in other jurisdictions, including the United States, against the Company or its Board Members or members of Management under the securities laws of those jurisdictions or entertain actions in Norway against the Company or the Board Members or members of Management under the securities laws of other jurisdictions. In addition, awards of punitive damages in actions brought in the United States or elsewhere may not be enforceable in Norway.

AVAILABLE INFORMATION

The Company has agreed that, for so long as any of the Shares are "restricted securities" within the meaning of Rule 144(a)(3) under the U.S. Securities Act, it will during any period in which it is neither subject to Sections 13 or 15(d) of the U.S. Securities Exchange Act of 1934 (the "**U.S. Exchange Act**"), nor exempt from reporting pursuant to Rule 12g3-2(b) under the U.S. Exchange Act, provide to any holder or beneficial owners of Shares, or to any prospective purchaser designated by any such registered holder, upon the request of such holder, beneficial owner or prospective owner, the information required to be delivered pursuant to Rule 144A(d)(4) of the U.S. Securities Act. The Company will also make available to each such holder or beneficial owner, all notices of shareholders' meetings and other reports and communications that are made generally available to the Company's shareholders.

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1. SUMMARY

INTRODUCTION

Warning................................ This summary should be read as an introduction to the Prospectus. Any decision to invest in the securities should be based on a consideration of the Prospectus as a whole by the investor. An investment in the Shares involves inherent risk and the investor could lose all or part of its invested capital. Where a claim relating to the information contained in this Prospectus is brought before a court, the plaintiff investor might, under national law, have to bear the costs of translating the Prospectus before the legal proceedings are initiated. Civil liability attaches only to those persons who have tabled the summary including any translation thereof, but only where the summary is misleading, inaccurate or inconsistent, when read together with the other parts of the Prospectus, or where it does not provide, when read together with the other parts of the Prospectus, key information in order to aid investors when considering whether to invest in such securities.

Securities............................. The Company has one class of shares in issue. The Shares are registered in book-entry form with the VPS and have ISIN NO 001 1157232.

Issuer.................................. The Company's registration number in the Norwegian Register of Business Enterprises is 927 866 951 and its LEI is 984500AEEH2D2AK42C11. The Company's registered office is located at Frøyas gate 13, 0273 Oslo, Norway, its main telephone number at that address is +47 949 83 159, and its website can be found at www.petronorep.com.

Competent authority........... The Financial Supervisory Authority of Norway (Nw.: *Finanstilsynet*), with registration number 840 747 972 and registered address at Revierstredet 3, 0151 Oslo, Norway, and telephone number +47 22 93 98 00 has reviewed and, on 25 February 2022, approved this Prospectus.

KEY INFORMATION ON THE ISSUER

Who is the issuer of the securities?

Corporate information......... The Company is a public limited liability company organised and existing under the laws of Norway pursuant to the Norwegian Public Limited Companies Act. The Company was incorporated in Norway on 1 October 2021, its registration number in the Norwegian Register of Business Enterprises is 927 866 951 and its LEI is 984500AEEH2D2AK42C11.

Principal activities............... PetroNor E&P Limited is an independent, African focused oil and gas exploration and production company based in Norway.

Major shareholders.............. Shareholders owning 5% or more of the Shares have an interest in the Company's share capital which is notifiable pursuant to the Norwegian Securities Trading Act. The following table sets forth shareholders owning 5% or more of the shares in the Company as the date of this Prospectus.

#	Shareholder	Number of shares	Percentage (%)
1	Petromal LLC	481,481,666	36.28%
2	NOR Energy AS	139,470,623	10.51%
3	Symero Limited	138,763,636	10.46%
4	Ambolt Invest AS	87,583,283	6.60%
Total		847,299,208	63.85%

Key managing directors……	The Company's Management consists of 5 individuals. The names of the members of the Management and their respective positions are presented in the below table.

Name	**Position**
Jens Pace	Interim Chief Executive Officer
Claus Frimann-Dahl	Chief Technical Officer
Michael Barrett	Exploration Manager
Emad Sultan	Strategy and Contracts Manager
Chris Butler	Group Financial Controller

Statutory auditor………………	The Company's auditor is BDO AS, with company registration number 993 606 650 and registered business address at Munkedamsveien 45A, N-0250 Oslo, Norway.

What is the key financial information regarding the issuer?

On 25 February 2022, the Group will have completed a Redomiciliation from Australia to Norway through an Australian scheme of arrangement, which involed establishing a new entity (being the Company) for the purposes of carrying out the Share Swap whereby shares in PetroNor E&P Ltd. (previously listed on Euronext Expand) ("**PetroNor Australia**") will be swapped for shares in the Company. The shares in PetroNor Australia we delisted in conjunction with the listing of the Company. As such, and under the Australian scheme, all of the shares held by PetroNor E&P Ltd. (Australia) shareholders were transferred to PetroNor E&P ASA. The shareholders will thus, in all material respects, be identical before and after the transaction. Therefore this will be treated as a continuance of business under the Company (being the new listing entity). The financial statements for the Company going forward will be presented as a continuance of the activities of the Australian company PetroNor Australia. The financial statements of PetroNor Australia have been prepared on the assumption that the Group will continue as a going concern with the realisation of assets and settlement of debt in normal operations. Accounts will be prepared in compliance with International Financial Reporting Standards (IFRS) as issued by the Accounting Standards Board and in accordance with the requirements of applicable Norwegian laws.

Key financials – Income statement

The table below sets out key financial information gathered from PetroNor Australia's unaudited consolidated income statement for the six-month period ended 30 June 2021 (prepared in accordance with IAS 34) and its audited consolidated income statement for the years ended 2020, 2019 and 2018 (prepared in accordance with IFRS).

	Six-month period ended 30 June		**Year ended 31 December**		
Key Financials – Income statement	**2021**	**2020**	**2020**	**2019**	**2018**
	USD	**USD**	**USD**	**USD**	**USD**
	IAS34	IAS34	IFRS	IFRS	IFRS
Total revenue	48.2	30.3	67.5	102.8	101.0
Operating profit	25.1	11.6	29.3	45.8	49.9
Net profit or (loss)	8.9	2.9	11.2	(5.8)	17.1
Operating profit margin *(%)*	52.1%	9.6%	43.4%	44.6%	49.4%
Basic earnings per share (USD cent)	0.30	(0.05)	0.24	(1.54)	0.96
Diluted earnings per share (USD cent)	0.30	(0.05)	0.24	(1.54)	0.96

Key Financials – Financial position

The table below sets out key financial information gathered from PetroNor Australia's unaudited consolidated statement of financial position for the six-month period ended 30 June 2021 with comparable figures for the same period of 2020 and its audited consolided statement of financial position as at 31 December 2020 with comparable figures for 2019 and 2018 (all prepared in accordance with IFRS).

Key Financials – Financial position	**As at 30 June**		**As at 31 December**		
	2021	**2020**	**2020**	**2019**	**2018**
	USD	**USD**	**USD**	**USD**	**USD**
	IAS34	IAS34	IFRS	IFRS	IFRS
Total assets	87.8	72.5	79.0	83.2	56.9
Total equity	38.3	18.5	22.3	21.3	26.6
Net financial debt *(interest-bearing debt less cash)*	(2.4)	3.9	4.8	(15.0)	(0.8)

Key Financials – Cash flow

The table below sets out key financial information gathered from PetroNor Australia's unaudited cash flow statements for the six-month period ended 30 June 2021 (prepared in accordance with IAS 34) and its audited consolidated cash flow statements for the years ended 2020, 2019 and 2018 (prepared in accordance with IFRS).

Key Financials – Cash flow	**Six-month period ended 30 June**		**Year ended 31 December**		
	2021	**2020**	**2020**	**2019**	**2018**
	USD	**USD**	**USD**	**USD**	**USD**
	IAS34	IAS34	IFRS	IFRS	IFRS
Net cash flows from operating activities	0.5	(11.6)	(2.9)	42.6	(1.1)
Net cash flows from investment activities	(3.7)	(2.1)	(7.6)	(12.5)	(4.0)
Net cash flows from financing activities	9.5	(3.1)	(3.2)	(10.2)	(5.0)

What are the key risks that are specific to the issuer?

Material risk factors…………

- Oil and gas exploration, development and production activities in countries in Africa are subject to significant political and economic uncertainties.
- The Group operates in countries with a high risk of corrupt practices, and corrupt practices of third parties or anyone working for the Group could adversely affect the Group.
- The COVID-19 pandemic has had, and may in the future have, a negative impact on the Group.
- Oil and gas prices are volatile and may fluctuate substantially, and sustained lower oil and gas prices may, inter alia, lead to a material decrease in the Group's net production revenues.
- The Group's estimates of reserves and resources are subject to uncertainties and may prove to be incorrect, which in turn could adversely affect i.e., the Group's financial condition and results of operations.
- The Company may not be able to find and develop or acquire economically recoverable reserves.
- There are risks related to the authorisations, permits and licenses upon which the Group depends, including the risk that licences may not be upheld or renewed.
- The legal disputes in which the Group is involved could adversely affect the Group.

- Failure by a licence partner to satisfy its obligations in relation to a licence may result in the other licence partners (including the Group) being liable for such failure.
- The Group's acquisitions may not be successful, including the Aje Transaction which has not yet been completed.

KEY INFORMATION ON THE SECURITIES

What are the main features of the securities?

Type, class and ISIN……….	All of the shares are ordinary shares in the Company are and have been created under the Norwegian Public Limited Companies Act. The Shares are registered in book-entry form with the VPS and have ISIN NO NO 001 1157232.
Currency, par value and number of securities…………	The Shares will be traded in NOK on Oslo Børs. As of the date of this Prospectus, the Company's share capital is NOK 1,326,991.006 divided into 1,326,991,006 Shares, each with a nominal value of NOK 0.001.
Rights attached to the securities………………………….	The Company has one class of shares in issue, and in accordance with the Norwegian Public Limited Companies Act, all shares in that class provide equal rights in the Company. Each of the Shares carries one vote.
Transfer restrictions…………	The Shares are freely transferable. The Articles of Association do not provide for any restrictions on the transfer of Shares, or a right of first refusal for the Shares. Share transfers are not subject to approval by the Board of Directors.
Dividend and dividend policy…………………………………	The Company’s objective is to create lasting value and provide competitive returns to its shareholders through profitability and growth and long-term returns to shareholders in the form of increased share price as well as dividends. Dividends are assumed to arise in line with the growth in the Company’s results while at the same time recognizing the opportunities for adding value through new profitable investments. Up to and including the date of this Prospectus, the Company has neither declared nor paid any dividends.

Where will the securities be traded?

Subject to certain customary conditions being satisfied, Oslo Børs approved the listing of the Shares on 16 February 2022 with commencement of trading in the Shares on Oslo Børs expected on or about 28 February 2022. The Company has not applied for admission to trading of the Shares on any other stock exchange, regulated market or multilateral trading facility (MTF).

What are the key risks that are specific to the securities?

Material risk factors…………

- The trading volume (liquidity) of the Shares may be limited.
- Petromal and NOR could, as major shareholders, each exercise significant influence over the Company, and the commercial goals and interests of these shareholders may not always be aligned with those of the Company and/or other shareholders.
- The Group may not be able to pay dividends either now or for the foreseeable future.
- Investors could be unable to recover losses in civil proceedings in jurisdictions other than Norway.
- Norwegian law could limit shareholders' ability to bring an action against the Company.

- Investors could be unable to exercise their voting rights for Shares registered in a nominee account.
- Pre-emptive rights to subscribe for Shares in additional issuances could be unavailable to U.S. or other shareholders.
- Future issuances of Shares or other securities with dilutive potential could dilute the holdings of shareholders and could materially affect the price of the Shares.

KEY INFORMATION ON THE OFFER OF SECURITIES TO THE PUBLIC AND THE ADMISSION TO TRADING ON A REGULATED MARKET

Under which conditions and timetable can I invest in this security?

Terms and conditions of the offering……………………	N/A
Timetable in the offering…………………………	N/A
Admission to trading…………………………..	Subject to certain customary conditions being met, Oslo Børs approved the listing of the Shares on 16 February 2022 with commencement of trading in the Shares on Oslo Børs exepected on or about 28 February 2022. The Shares are expected to trade under the ticker code PNOR.
Distribution plan……………	N/A
Dilution……………………….….	N/A
Total expenses of the issue/offer……………………..	The Company estimates that its expenses in connection with the Norwegian Listing on Oslo Børs will amount to approximately USD 250,000.

Who is the offeror and/or the person asking for admission to trading?

The Company is the person asking for admission to trading.

Why is this prospectus being produced?

Reasons for the offer/admission to trading……………………………	The Company believes that the Listing will: - further enhance the Group's profile with investors, business partners, suppliers and customers; - allow for a more liquid market for the Shares; - facilitate for a more diversified shareholder base and enable additional investors to take part in the Group's future growth and value creation; - enable the Company to implement stock based incentive schemes for the Board of Directors, Management and employees; - streamline the Group's corporate structure and reduce corporate overheads which have not yet been executed. - provide better access to capital markets; and

- further improve the ability of the Group to attract and retain key management and employee.

Use of proceeds……………….. N/A

Conflicts of interest………….. N/A

2. RISK FACTORS

An investment in the Company and the Shares involves inherent risk. Investors should carefully consider the risk factors and all information contained in this Prospectus, including the financial statements and related notes. The risks and uncertainties described in this Section 2 "Risk factors" are the material known risks and uncertainties faced by the Group as of the date hereof that the Company believes are the material risks relevant to an investment in the Shares. An investment in the Shares is suitable only for investors who understand the risks associated with this type of investment and who can afford to lose all or part of their investment.

The risk factors included in this Section 2 are presented in a limited number of categories, where each risk factor is sought placed in the most appropriate category based on the nature of the risk it represents. Within each category the risk factors deemed most material for the Group, taking into account their potential negative affect for the Company and its subsidiaries and the probability of their occurrence, are set out first. This does not mean that the remaining risk factors are ranked in order of their materiality or comprehensibility, nor based on a probability of their occurrence. The absence of negative past experience associated with a given risk factor does not mean that the risks and uncertainties in that risk factor are not genuine and potential threats, and they should therefore be considered prior to making an investment decision. If any of the following risks were to materialize, either individually, cumulatively or together with other circumstances, it could have a material adverse effect on the Group and/or its business, results of operations, cash flows, financial condition and/or prospects, which may cause a decline in the value and trading price of the Shares, resulting in loss of all or part of an investment in the Shares.

2.1. Risks related to the countries in which the Group operates

2.1.1. The Group operates in developing countries facing political, economic and social uncertainties

The Group participates or expects to participate in oil and gas projects in countries in West Africa with emerging economies, such as the Republic of Congo ("**Congo**"), Nigeria, The Gambia, Senegal and Guinea-Bissau. Oil and gas exploration, development and production activities in such emerging markets are subject to significant political and economic uncertainties that may have a material adverse effect on the Group. Uncertainties include, but are not limited to, the risk of war, terrorism, expropriation, nationalization, renegotiation or nullification of existing or future licences and contracts, changes in crude oil or natural gas pricing policies, changes in taxation and fiscal policies, imposition of currency controls and imposition of international sanctions. Travel bans, asset freezes or other sanctions may be imposed and have historically been imposed on countries in which the Group operates.

The jurisdictions in which the Group operates may also have less developed legal systems than more established economies which 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. In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system 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 susceptible to revision or cancellation and legal redress may be uncertain or delayed. There can be no assurance that joint ventures, 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.

These risk factors, all of which are beyond the Group's control, could have a material adverse effect on the Group's business, prospects, financial position and/or results of operations.

2.1.2. The Group operates in countries with a high risk of corrupt practices

The jurisdictions in which the Group has operations have a low score on Transparency International's Corruption Perception Index, which implies that these countries are perceived as jurisdictions where there is a higher risk of corruption. The Group's current assets are located in Congo, the Gambia, Senegal and Guinea-Bissau. In addition, the Group has entered into a definitive agreement to acquire assets in Nigeria (which is subject to completion). The Group may also target acquisitions in other countries in Africa. The production sharing or other licencing contracts in such jurisdictions may provide for payments to the Governments and/or national oil companies (farm-in fees, signature bonuses, taxes, training budgets, equipment budgets, carry of certain expenditures etc.). Furthermore, the Group has a number of consultants working for it in the area. Although the Group believes all its consultancy agreements are entered into on clear and transparent terms, there is a risk that agents or other persons acting on behalf of the Group may engage in corrupt activities without the knowledge of the

Group. Under applicable laws relating to the Group's assets, local participation is or may be required in the oil and gas sector, but it may prove difficult to always receive final confirmation as to who the ultimate owners and affiliations of such local partners are. Through the Group's investigation, it has not been possible to substantiate ultimate ownership and affiliations of all, current local partners in Congo and there can be no assurance that there are no government affiliations within the ultimate shareholders of the local partners in Congo.

Corrupt practices of third parties or anyone working for the Group or any of its affiliated parties, or allegations of such practices, may have a material adverse effect on the reputation, performance, financial condition, cash flow, prospects and/or results of the Group.

2.2. Risks related to the business of the Group

2.2.1. Risks related to COVID-19 and other public health crises

The Group's business, operations and financial condition could be materially and adversely affected by the outbreak of epidemics or pandemics or other health crises. In December 2019, COVID-19 was reported to have surfaced in Wuhan, China; on 30 January, 2020, the World Health Organization ("**WHO**") declared the outbreak a global health emergency; and on 11 March, 2020 the WHO declared the outbreak of COVID-19, a global pandemic. The outbreak has spread throughout most of the world, and COVID-19 has led companies and various international jurisdictions to impose restrictions such as quarantines, business closures and travel restrictions. While these effects are expected to be temporary, the duration of the business disruptions internationally and related financial impact cannot be reasonably estimated at this time.

The Group operates in developing countries in Africa (such as Congo, Guinea Bissau, Gambia, Senegal and Nigeria) where political, economic and social instability is expected to have increased as a result of COVID-19. Furthermore, the global supply chains relied on by the Group have experienced significant disruptions during the COVID-19 crisis. Related to the COVID-19 pandemic is volatility in oil prices which at times has resulted in significant price decreases. The Group's operations are also assumed to have been delayed in jurisdictions where strict local restrictions have been imposed. On this basis and given the many uncertainties relating to the COVID-19 situation, there can be no assurances that the COVID-19 situation hasn’t had or will not have a material adverse effect on the Group's business, results of operations and financial condition.

2.2.2. The Group is affected by the level of oil and gas prices, which are highly volatile

The Group's revenues, cash flow, reserve estimates, profitability and rate of growth depend substantially on prevailing international and local prices of oil and gas. Prices for oil and gas may fluctuate substantially based on factors beyond the Group's control. Consequently, it is impossible to accurately predict future oil and gas price movements. Oil and gas prices are volatile and have witnessed significant changes in recent years, for many reasons including, but not limited to, changes in global and regional supply and demand, geopolitical uncertainty, availability of equipment and new technologies, weather conditions and natural disasters, terrorism as well as global and regional economic conditions. Sustained lower oil and gas prices or price declines may inter alia lead to a material decrease in the Group's net production revenues.

Sustained lower oil and gas prices may also cause the Group to make substantial downward adjustments to its oil and gas reserves. If this occurs, or if the Group's estimates of production or economic factors change, the Group may be required to write-down the carrying value of its proved oil and gas properties for impairments. In addition, the depreciation of oil and gas assets charged to its income statement is dependent on the estimate of its oil and gas reserves. If oil and gas prices remain depressed over time, it could also reduce the Group's ability to raise new debt or equity financing or to refinance any outstanding loans on satisfactory terms.

2.2.3. Reserves and contingent resources are inherently uncertain in respect of the inferred volume range

Included in this Prospectus is information relating to the reserves and resources of certain of the Group's assets. Reserves are defined as the volume of hydrocarbons that are expected to be produced from known accumulations in production, under development or with development committed. Reserves are also classified according to the associated risks and probability that the reserves will actually be produced.

Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond the Group's control and therefore these assumptions may prove to be incorrect over time. For example, sustained lower oil and gas prices may cause the Group to make substantial downward adjustments to its oil and gas reserves and resources. If this occurs, or the Group's estimates of production or economic factors change, the Group may be required to write-down the carrying value of its proved oil and gas properties for impairments. In addition, the depreciation of oil and gas assets charged to its income statement is dependent on the estimate of its oil and gas reserves.

The reserves and resources related to PNGF Sud and PNGF Bis are based on a competent reserves report prepared by AGR Petroleum Resources AS ("**AGR**") as of 31 December 2020. However, reserves and resource estimate for the Aje Field (as defined below) (acquisition of the Aje Field pending completion of the Aje Transaction (as defined below)) and resource estimates for assets in Guinea-Bissau, The Gambia and Senegal are not verified by independent third parties and there is a risk that a third-party verification would lead to a downwards adjustment of reserves or resources estimates related to these assets.

If the assumptions upon which the estimates of the Group's oil and gas reserves or resources are based prove to be incorrect, the Group may be unable to recover and/or produce estimated levels or quality of oil or gas, which could have a material adverse effect on the Group's business, prospects, financial condition or results of operations.

2.2.4. The Group is dependent on finding/acquiring, developing and producing oil and gas reserves that are economically recoverable

The future success of the Group depends in part on its ability to find and develop or acquire additional reserves that are economically recoverable, which is dependent, inter alia, on oil and gas prices. Oil and gas exploration and production activities are capital intensive and inherently uncertain in their outcome. The Group's offshore exploration acreage is located in largely unexplored sections of the West African Atlantic margin. Some of the Group's projects are in an early exploration stage, and there is a risk that any future exploration programs on these and any licence the Group may acquire in the future (whether offshore or onshore) may be unsuccessful and may not discover commercial quantities of hydrocarbons.

Drilling oil and gas wells (whether offshore or onshore) is by its nature highly speculative, may be unprofitable and may result in a total loss of the investments made by the Group. In particular, completed wells may never produce oil or gas or may not produce sufficient quantities or qualities of oil and gas to be profitable or commercially viable. Moreover, geological formations and proximity with neighbouring fields may result in a regulatory requirement to unitize the licence area with a neighbouring field. Such processes may prove complex, and thereby cause delays and uncertainties in respect of the Group's ultimate interest in the unitized field.

All of these risks may have a material adverse effect on the Group, its financial condition, cash flow, prospects and/or operations.

2.2.5. Approvals, permits and licences may not be upheld or renewed

Under applicable laws and regulations in certain of the countries where the Group operates, the Group will be required to renew its licenses with respect to exploration activities. In addition, the Group would be required, subject to commercial petroleum discoveries being made, to apply for exclusive exploitation authorisations. For example, the current license partnership on PNGF Sud has through an umbrella agreement, the right to negotiate the licence terms for entering into a production sharing contract for the adjacent PNGF Bis license. The management remains positive in terms of negotiating and signing a production sharing contract for the PNGF Bis licence with the relevant governmental bodies, but no assurance can be given as to whether the Group will be able to agree on terms satisfactory to the Group and no assurances can be given to the interest allocated the Group. Further, the definitive agreement to acquire an interest in the OML-113 permit in Nigeria, which contains the Aje Field, the completion of which is expected to be finalized by 30 April 2022. Further, the A4 license in Gambia will expire in October 2022 unless the Group commits to drilling of an exploration well and, the licenses in Senegal are currently in arbitration, see Section 2.2.6.

If any of these exploration and production licences, or any other licenses of the Group, are not renewed or granted, or exclusive exploitation authorisations are not obtained or upheld, the Group would be required to cease operations within these licences. The loss of some or all of the Group's licences may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

Further, consents are normally required in order to carry out operations on oil and gas fields, such as drilling operations, installation of production facilities etc. Delays in, or lack of success in obtaining various approvals may affect the economic and commercial attractiveness for such licence interests, in which case the Group’s financial position and future prospects could also be materially weakened.

2.2.6. Risks associated with current, pending or threatened legal disputes and litigation

The Group is, and may from time to time be, involved in legal disputes and legal proceedings related to the Group's operations or otherwise. To the extent the Group becomes involved in legal disputes in order to defend or enforce any of its rights or obligations under its licences, agreements or otherwise, such disputes or related litigation may be costly, time consuming and the outcome may be highly uncertain. Furthermore, legal proceedings could be ruled against the Group and the Group could be required to, inter alia, pay damages, halt its operations, stop its expansion or development projects or relinquish its oil and gas licences. It is further a risk that the Group could become involved in legal disputes with uninsured third parties. Even if the Group would ultimately prevail (which cannot be assured), such disputes and litigation may have a substantially negative effect on the Group, its financial condition, cash flow, prospects and/or its operations. The occurrence of any such event could have a material adverse effect on the Group's business, prospects, financial position and/or results of operations.

As at the date of this Prospectus, the Group is involved, inter alia, as the claimant in ICSID arbitration case ARB/18/24 in relation to its 90% interest in the Rufisgue Offshore Profond block ("**ROP**") and the Senegal Offshore Sud Profond block ("**SOSP**") licences in Senegal. The Group is dependent on a successful outcome of the negotiation with the Senegalese government or a successful outcome in the arbitration case in order to have its respective licences re-instated. The Group has no control over the outcome of the arbitration case. Should the outcome of the negotiations or the arbitration case be unfavorable to the Group, there is a risk that could result in a payment of the costs associated with the arbitration and / or damages, as well as the loss of the ROP and/or SOSP licenses which may have an impact on the Group’s status in respect of the size and position of its exploration portfolio.

Hemla Africa Holding AS ("**HAH**") is in dispute with a former employee of Hemla E&P Congo S.A. ("**HEPCO**") concerning a claim for (indirect) ownership in HEPCO. The former employee argues that he is entitled to an (indirect) ownership position in HEPCO, including past dividends taking such ownership position into account. The former employee has filed the claim before the Commercial Court in Pointe-Noire. He has also filed a petition for arrest, relating to HAH's shares in HEPCO. The claim is based on an alleged promise of shares in HEPCO. The claim is disputed by HEPCO. Should the previous employee’s claims before the Commercial Court in Pointe-Noire and a potential appeal by MGI in the Republic of Congo be ruled against the Group, such rulings may have a substantial negative impact on the Group’s financial condition, cash flow as well as leading to a reduction of the Group's net ownership in the Congolese licenses.

In January 2021, HAH gained control of an additional 9,900 shares in HEPCO, shares previously held by the minority shareholder, MGI International S.A. (“**MGI**”), and resultantly HAH increased its net ownership in the PNGF Sud licenses from 14.85% to 16.83% and in the PNGF Bis licenses from 20.79% to 23.56%. The share increase occurred subsequent to a debt repayment default concerning a loan arrangement between HAH as lender and MGI as borrower, where the shares were pledged in favour of HAH. The default has been disputed by MGI and has been subject to several court proceedings in the Republic of Congo, all of which have resulted in rulings in the favour of HAH. It is expected that MGI will make a further appeal, with the final outcome and timing of such a further appeal ruling being uncertain. Should MGI appeal and the outcome of such appeal process be in favour of MGI, it is expected that HAH would have to transfer ownership of the 9,900 shares in HEPCO back to MGI. While there are no legal restrictions on the ability of HAH to exercise ownership rights over the shares in question, it cannot be ruled out that there will be additional legal processes and action taken by MGI that could influence HAH's ownership to these shares. It is further a risk that unfavorable rulings in the ICSID arbitration, the claims in Commercial Court in Pointe-Noire and a possible MGI appeal could be awarded within close proximity to one another with regards to timing, which may have a substantially negative effect on the Group, its financial condition, cash flow, prospects and/or its operations.

2.2.7. Risk of joint and several liabilities with its licence partners

Under each licence, the Group is liable on a joint and several basis together with its licence partners for the liabilities of the licence group (including but not limited to decommissioning liabilities). Whilst such joint and several liability is regulated among the licence group through the joint operating agreement, failure by a licence partner to satisfy its obligations may ultimately result in the other licence partners (including the Group) being liable for such failure and therefore increase the Group's exposure related to the licence in question. As a consequence of joint and several liabilities, any failure by a licence partner to satisfy any significant obligations may have a material adverse effect on the Group's business, financial condition, operating results and/or cash flow.

2.2.8. The Group may not have adequate insurance or insurance may be unavailable or too costly

Oil and natural gas exploration, development, and production operations are subject to associated risks and hazards, such as fire, explosion, blowouts, gas leakages and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment or personal injury. Insurance against all risks associated with oil and gas production is not available or affordable. The Group will maintain insurance where it is considered appropriate for its needs, however, it will not be insured against all risks because appropriate cover is not available or because the Group considers the required premiums to be excessive having regard to the assumed benefits that would accrue. The Group may incur material uninsured losses or damages that may have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

2.2.9. Production sharing contracts with governments

Production sharing contracts (singular "**PSC**", plural "**PSCs**") are industry standard contracts signed between a government and a resource extraction company. The Group has entered into certain PSCs with local governments. Accordingly, the production resulting from oil operations must be shared between the Group and such government. The local governments also have an option to increase its participation in the relevant licences. The sharing of the production will naturally affect the profitability of the Group and/or the amount of profits from the project that will flow to the Company and its shareholders. This could be affected further if the government decides to increase its participation or the size of its share

2.2.10. Local authorities may impose additional financial or work commitments

The Group's license interests for the exploration and exploitation of hydrocarbons will typically be subject to certain financial obligations or work commitments as imposed by local authorities. The existence and content of such obligations and commitments may affect the economic and commercial attractiveness for such license interest. No assurance can be given that local authorities do not unilaterally amend current and known obligations and commitments. If such amendments are made in the future, the value and commercial and economic viability of such interest could be materially reduced or even lost, in which case the Group's financial position and future prospects could also be materially weakened. The Group's current or future development projects are associated with risks relating to delays, cost inflation, potential penalties and regulatory requirements. Development projects inter alia involve complex engineering, procurement, construction work, and drilling operations to be carried out which may require related governmental approvals to be obtained prior to commencement of production. The exploration and development periods of a license are commonly associated with higher risk, requiring high levels of capital expenditure without a commensurate degree of certainty of a return on that investment. The complexity of offshore development projects also makes them very sensitive to delays or costs increases. Current or future projected target dates for production may be delayed and significant cost overruns may incur. The Group's estimated exploration costs are subject to a number of assumptions that may not materialize. Such factors may again impact to what extent fields to be developed are fully funded or remain commercially viable, and consequently could result in breach by the Group of its obligations and/or require the Group to raise additional debt and/or equity. Any delays, cost increases or other negative impact relating to the current or future development projects of the Group, may have a material adverse effect on its business, results of operations, cash flow, financial condition and prospects.

2.2.11. The Group's production is concentrated in a limited number of hydrocarbon fields

Currently, all of the Group's production comes from fields in the PNGF Sud licence in Congo. The Aje Transaction, if completed, will add a producing asset in Nigeria. Under any circumstance, the Group's operations and cash flow will be restricted to a very limited number of fields. If mechanical or technical problems, storms, shutdowns or other events or problems affect the current or future production of the current producing assets of the Group, or new fields coming into production, it may have direct and significant impact on a substantial portion of the Group's production and hence the Group's revenue, profits and financial position as a whole. Further, if the actual reserves associated with any one of the Group's fields are less than anticipated, this may result in material adverse effects for the Group, including on the Group's ability to make new investments and raise financing.

2.2.12. Risks related to ongoing transactions

In the second half of 2019, PetroNor E&P Ltd. entered into an agreement with Panoro Energy ASA for the acquisition of certain companies holding interests in the OML-113 licence (Aje Field) offshore Nigeria.

The acquisition is conditional upon the satisfaction of certain conditions precedent, including the authorisation of the Nigerian Department of Petroleum Resources and the consent of the Nigerian Minister of Petroleum Resources, which was granted on 27 January 2022. The long stop date for the completion of the transaction is 30 April 2022.

No assurances can be given to the successful completion of the transaction. Consequently, there is a risk that investors subscribing for shares will experience that the acquisition does not complete or is delayed.

An unsuccessful completion of the transaction can potentially have a negative effect on the reputation, performance, financial condition, cash flow, and/or results of the Group. An unsuccessful completion of the transaction may also result in disputes.

There is limited reliable financial information on Pan-Petroleum Nigeria Holdings BV and Pan-Petroleum Services Holdings BV and the Aje Field and there is a risk that the economic assumptions made by the Company in connection with the transaction are incorrect or incomplete and proves to be less favourable than anticipated by the Group upon making the business decision to acquire the assets. Further, there is risk that future production, costs, reserves figures or other relevant factors affecting the value of the assets and cash flow proves to be less favourable than anticipated by the Company upon making the business decision to acquire the assets.

All of these risks, if they were to occur, may have a material adverse effect on the reputation, performance, financial condition, cash flow, prospects and/or results of the Group.

Further, if completion is delayed or the acquisitions do not complete, there can be no assurance that the Group would be able to acquire interests at a later stage, which could have negative effect on the Group's ability to develop its business and achieve future growth. In addition, the Group’s continued operations will be less diversified, with the Group's production remaining concentrated in a limited number of hydrocarbon fields within the PNGF Sud asset in Congo, issues with which could have a negative effect on the Group's business, results of operations, financial conditions and/or prospects.

2.2.13. Risks related to decommissioning activities and related costs

Several of the Group’s license interests concern fields which have to be decommissioned. The Group expects to develop and invest in existing and new fields, which increases the Group’s future decommissioning liabilities. There are significant uncertainties relating to the estimated liabilities, costs and time for decommissioning of the Group’s current and future licenses. Such liabilities are derived from legislative and regulatory requirements and require the Group to make provisions for such liabilities.

Decommissioning requires complex engineering, procurement and execution of work, including the plugging of production wells, giving rise to the risk of inadequate engineering, procurement or execution. This may result in delays, cost overruns, damage to facilities and properties, environmental damage, injury to persons and loss of life. It is, therefore, difficult to forecast accurately the costs that the Group will incur in satisfying decommissioning liabilities. No assurance can be given that the anticipated cost, timing of removal and timing of provisions are correct and any deviation from current estimates or significant increase in decommissioning costs relating to the Group’s previous, current or future licenses, may have a material adverse effect on the Group business, results of operations, financial condition, cash flow and/or prospects of the Group's ultimate interest in the fields.

2.2.14. Climate change abatement legislation, protests against fossil fuel extraction and regulatory, technological and market improvements

Continued political attention to issues concerning climate change, the contribution of man activity and anthropogenic emissions towards global warming, and potential mitigation through regulation could have a material impact on the Group’s business. International agreements, national and regional legislation, and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. For example, the EU established a detailed EU taxonomy (Regulation (EU) 2020/852 as well as delegated acts), a classification system for sustainable activities. Given the Group’s operations are associated with emissions of “greenhouse gases”, these and other greenhouse gas emissions related laws, policies and regulations may result in substantial capital, compliance, operating and maintenance costs. The level of expenditure required to comply with these laws and regulations is uncertain and is expected to vary depending on the laws enacted by particular countries. As such, climate change legislation and regulatory initiatives restricting emissions of greenhouse gases may adversely affect its operations, the Group’s cost structure or the demand for oil and gas. Further political and regulatory initiatives, technological development and market changes may substantially improve the operating conditions within the renewable energy sector, which may in turn adversely affect the oil and gas industry. Such legislation or regulatory initiatives could have a material adverse effect by diminishing the demand for oil and gas, increasing the Group’s cost structure or causing disruption to its operations by regulators. As the Group has made significant investments in order to build requisite operating facilities, drilling of production wells along with implementation of advanced technologies for the extraction and exploitation of hydrocarbons, there can be no assurance that the Group may be able to carry out an energy transition to a low-carbon and climate resilient future or be able to comply with changes in climate and energy policies, or be able to comply with the EU taxonomy. In addition, the Group may be subject to activism from groups campaigning against fossil fuel extraction, which could affect its reputation, disrupt its campaigns or programs or otherwise negatively impact the Group’s business, prospects, financial condition and/or results of operations.

2.2.15. Risks relating to legal charges against individuals who are major shareholders of - and related to the Company

Reference is made to the description of the ongoing prosecution against persons who are major shareholders of- and related to the Company, as further set out in Section 2.4.1 "Risks related to legal charges against individuals who are major shareholders of – and related to the Company".

The Company assumes that it has suffered, and may continue to suffer in the future, reputational damage as a result of the ongoing prosecution against these individuals. Furthermore, there can be no assurances that the ongoing prosecution will not extend to other persons or entities relating to the Company. Until the matter has been finally concluded by the relevant authorities, the ongoing prosecution and any reputational damage as a result of such may complicate the Group's dealing with third parties and the authorities and its raising of debt and equity financing as a result of increased KYC scrutiny, any of which may have a material impact on the Group's business and financial prospects.

2.3. Financial risks

2.3.1. The Group may not be able to raise financial indebtedness for future growth

The Group's activities are and will continue to be capital intensive. The Group expects future investments into existing and new hydrocarbon assets to be served by cash-flow from ongoing operations. However, it is also expected that the Group will look to raise debt to part-fund future growth. Such debt may not be readily available, or only be available at terms which are unattractive or adversely impact the profitability of investments. Restrictions in raising, or the unavailability of, debt may restrict the Group from growing as planned and may result in the Group having to forego attractive investment opportunities, which in turn could have a negative impact on the Group's financial position and future prospects.

2.3.2. Risks associated with foreign exchange risk, including CEMAC and UEMOA currency exchange regulations.

The Group operates in jurisdictions that are part of the West African Economic Monetary Union ("**UEMOA**") and the Central African Economic and Monetary Commission ("**CEMAC**") and as such are subject to conforming to new regulations that are to be enforced by member state governments and commercial banks regarding offshore foreign currency accounts, onshore accounts in foreign currencies and obligations regarding the repatriation of exportation proceeds.

The foreign currency restrictions require special approvals on the opening of new and the operation of existing foreign currency accounts outside of the UEMOA and CEMAC areas where such accounts are utilised to receive proceeds of the sale of oil which may be granted for a period of up to a two years and subject to renewals, also for opening foreign currency accounts in the UEMOA or CEMAC areas, prohibition of foreign currency withdrawals inside the UEMOA or CEMAC areas, requirements for all loans to be declared with the local central bank and there is a risk of forced conversion to CFA of funds held in USD in abandonment fund reserve accounts.

The Group's operations in the Republic of Congo and Guinea Bissau are, in principle, covered by the restrictions. If the foreign currency restrictions were to be imposed on and enforced against the Group, this could restrict the Group's ability to repatriate earnings from the operations at effected countries, pay dividends from subsidiaries and repay or refinance any future loan facilities, which would entail extensive documentation and fee requirements and increased administrative burdens on the Group's operations, and the directors of Group companies that fail to comply may be subject to fines and other penalties. The imposition of the foreign currency restrictions may have a material adverse effect on the Group's business, operations, cash flows and financial condition in the CEMAC and UEMOA areas.

2.4. Risks related to the Shares

2.4.1. Risks related to legal charges against individuals who are major shareholders of - and related to the Company

On 15th December 2021, the National Authority for Investigation and Prosecution of Economic and Environmental Crime (Nw.: *Økokrim*) in Norway announced in a press release that they had entered the Company's premises in Oslo in relation to suspicion of a criminal offence committed by individuals related to the Group, including its previous CEO and his business companion who together hold shares in the Company through the entity NOR, and the previous CEO also hold shares in the Company through other entities as further set out in Section 14.5 "Ownership structure". On the same day, the Group announced that it had no reason to believe that there were any suspicions against it. On the subsequent day, Økokrim announced that the investigations were related to the individuals in question on suspicion of corruption concerning undisclosed projects in Africa, in addition to confirming that no charges had been brought against the Group or other companies.

Although no charges have been brought against any Group company as such, there are several currently unknown factors relating to the above investigations which could result in a reduced market price of the Company's shares, especially taking into account that the charges concern individuals related to the Company and "(…) *projects in Africa (…)*" as announced by Økokrim on 16th December 2021. Further, should Økokrim's suspicions following investigations of the matter prove to be partially or fully correct and lead to an indictment and/or conviction of one or both the individuals in question, or lead to prosecution and/or indictment of other persons or entities relating to the Company, such developments may have a material adverse effect on the market price of the Company's shares.

2.4.2. There is limited liquidity in the Shares due to, inter alia, a low spread among shareholders

From time to time, the Shares experience low trading volumes, despite being listed on Euronext Expand. Historically, the relative size of Shares being "freely floated" (meaning Shares not controlled by shareholders having more than 10% of the total shares and shares held by management, directors, key employees and certain other stakeholders in the company, and their respective affiliates) have been lower than the general requirement on Euronext Expand (which is 25%). Although recently the Company has achieved a free float in excess of 25%, the trading volume in the Shares may still be limited, which in turn may result in the market capitalization of the Company being lower compared to a situation with high trading volumes. Also, no assurances can be given that the free float in the future will not fall below 25%. This may result in owners of the Company's Shares having difficulties in liquidating their positions in a short amount of time at the prevailing market price of the Shares, and as such, there can be no assurances that there will be sufficient liquidity in the Shares.

2.4.3. Limitations on dividends

The Company currently anticipates that it will retain all future earnings, if any, to finance the growth and development of its business. The Company does not intend to pay cash dividends in the foreseeable future. Any payment of cash dividends will depend upon the Group's financial condition, capital requirements, earnings and other factors deemed relevant by its Board and general meeting of shareholders.

2.4.4. Risks related to politically exposed persons

One of the ultimate beneficial shareholders of the Company as well as one director of the Company are politically exposed persons ("**PEP**"). Further, one or more ultimate beneficial shareholders of one of the Company's subsidiaries, HEPCO (as defined above), may also be a PEP. See Section 13.2 "Board of directors" and the notes beneath the legal structure chart in Section 14.2 "Legal structure" for further details. The Company has not received any firm confirmations in this respect, but has nonetheless received indications that this may be the case.

Being a politically exposed person is defined in the EU Anti Money Laundering Directive IV (Directive (EU) 2015/849)) article 3 (9) as a natural person who is or who has been entrusted with prominent public functions. The definition includes the following: (a) heads of State, heads of government, ministers and deputy or assistant ministers; (b) members of parliament or of similar legislative bodies; (c) members of the governing bodies of political parties; (d) members of supreme courts, of constitutional courts or of other high-level judicial bodies, the decisions of which are not subject to further appeal, except in exceptional circumstances; (e) members of courts of auditors or of the boards of central banks; (f) ambassadors, chargés d'affaires and high-ranking officers in the armed forces; (g) members of the administrative, management or supervisory bodies of State-owned enterprises; (h) directors, deputy directors and members of the board or equivalent function of an international organisation. No public function referred to in points (a) to (h) shall be understood as covering middle-ranking or more junior officials. PEPs are typically subject to increased KYC scrutiny, as they are considered to hold the potential to expose the financial sector to significant reputational and legal risks. International efforts to combat corruption are also part of the justification given for the need to pay particular attention to such persons and to apply appropriate enhanced customer due diligence measures with respect to persons who are or who have been entrusted with prominent public functions domestically or abroad and with respect to senior figures in international organisations. It should be noted however that the requirements relating to PEPs are intended to be of a preventive and not criminal nature, and should not be interpreted as stigmatising politically exposed persons as being involved in criminal activity.

The existence of one or more PEPs in relation to the Company creates risk in relation to the Company's dealings with third parties and the authorities, may complicate raising of debt and equity financing as a result of increased KYC scrutiny involved due to PEP relations, which may in turn have a material impact on the Group's business and financial prospects. Having one or more PEPs related to a company will typically increase the risk of enhanced customer due diligence measures from third parties dealing with the company, as this is usually required according to EU law, the law of countries which have implemented the Financial Action Task Force recommendations and the law of similar jurisdictions. Enhanced customer due diligence in relation to PEPs will typically require the counterparty to obtain the approval from senior management in the counterparty before establishing or resuming the business relationship or transaction, performing additional measures to verify the source of wealth and funds involved in the business relationship or transaction, and conducting enhanced, ongoing monitoring of the business relationship. The enhanced customer due diligence measures may also include other measures which the counterparty sees fit to remove or confirm any suspicions of anti-money laundering or counter-terrorist financing.

2.4.5. Future issuances of Shares or other securities could dilute the holdings of shareholders and could materially affect the price of the Shares

The Company may in the future decide to offer and issue new Shares or other securities in order to finance new capital intensive projects, in connection with unanticipated liabilities or expenses or for any other purposes. As mentioned in this

Prospectus, the potential closing of the Aje transaction after the date of this Prospectus may dilute existing shareholder of the Company by the issuance of around 72 million new shares, which equals a dilution of around 5% based on the current amount of outstanding shares. Furthermore, and depending on the structure of any future offering, certain existing shareholders may not have the ability to purchase additional equity securities. An issuance of additional equity securities or securities with rights to convert into equity could reduce the market price of the Shares and would dilute the economic and voting rights of the existing shareholders if made without granting subscription rights to existing shareholders. Accordingly, the Company's shareholders bear the risk of any future offerings reducing the market price of the Shares and/or diluting their shareholdings in the Company.

2.4.6. Investors could be unable to recover losses in civil proceedings in jurisdictions other than Norway

The Company is a public limited company organized under the laws of Norway as a result of the Redomicilation, where the listed ultimate parent company and the Shares will be subject to applicable Norwegian law, as opposed to the previous listed entity PetroNor Australia. A total of 40% of the members of the Board of Directors and management reside in Norway. As a result, it may not be possible for investors to effect service of process in other jurisdictions upon such persons or the Company, to enforce against such persons or the Company judgments obtained in non-Norwegian courts, or to enforce judgments on such persons or the Company in other jurisdictions.

2.4.7. Norwegian law could limit shareholders' ability to bring an action against the Company

As a result of the Redomiciliation, the rights of holders of the Shares are governed by Norwegian law and by the Company's Articles of Association. These rights may differ from the rights of shareholders in other jurisdictions, including the jurisdiction relating to the previous listed entity, Australia. In particular, Norwegian law limits the circumstances under which shareholders of Norwegian companies may bring derivative actions. For example, under Norwegian law, any action brought by the Company in respect of wrongful acts committed against the Company will be prioritized over actions brought by shareholders claiming compensation in respect of such acts. In addition, it could be difficult to prevail in a claim against the Company under, or to enforce liabilities predicated upon, securities laws in other jurisdictions.

2.4.8. Investors could be unable to exercise their voting rights for Shares registered in a nominee account

Beneficial owners of the Shares that are registered in a nominee account (such as through brokers, dealers or other third parties) could be unable to vote for such Shares unless their ownership is re-registered in their names with the VPS prior to any general meeting of shareholders. There is no assurance that beneficial owners of the Shares will receive the notice of any general meeting of shareholders in time to instruct their nominees to either effect a re-registration of their Shares or otherwise vote for their Shares in the manner desired by such beneficial owners.

2.4.9. Pre-emptive rights to subscribe for Shares in additional issuances could be unavailable to U.S. or other shareholders

Under Norwegian law, which may deviate from Australian law which previously governed PetroNor Australia and shares issued by it, unless otherwise resolved at the Company's general meeting of shareholders, existing shareholders have pre-emptive rights to participate on the basis of their existing ownership of Shares in the issuance of any new Shares for cash consideration. Shareholders in the United States, however, could be unable to exercise any such rights to subscribe for new Shares unless a registration statement under the U.S. Securities Act is in effect in respect of such rights and Shares or an exemption from the registration requirements under the U.S. Securities Act is available. Shareholders in other jurisdictions outside Norway, could be similarly affected if the rights and the new Shares being offered have not been registered with, or approved by, the relevant authorities in such jurisdiction.

The Company is under no obligation to file a registration statement under the U.S. Securities Act or seek similar approvals under the laws of any other jurisdiction outside Norway in respect of any such rights and Shares. Doing so in the future could be impractical and costly. To the extent that the Company's shareholders are not able to exercise their rights to subscribe for new Shares, their proportional interests in the Company will be diluted.

3. RESPONSIBILITY FOR THE PROSPECTUS

This Prospectus has been prepared in connection with the Listing of the Shares on Oslo Børs described herein.

The Board of Directors of PetroNor E&P ASA accepts responsibility for the information contained in this Prospectus. The members of the Board of Directors confirm that, after having taken all reasonable care to ensure that such is the case, the information contained in this Prospectus is, to the best of their knowledge, in accordance with the facts and contains no omission likely to affect its import.

Oslo, 25 February 2022

The Board of Directors of PetroNor E&P ASA

Eyas A. Alhomouz *Chair*	Gro Gauthun Kielland *Board member*
Ingvil Smines Tybring-Gjedde *Board member*	Joseph Iskander *Board member*

4. GENERAL INFORMATION

4.1. Other important investor information

This Prospectus has been approved by the Norwegian FSA, as competent authority under the EU Prospectus Regulation. The Norwegian FSA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by the EU Prospectus Regulation, and such approval should not be considered as an endorsement of the issuer or the quality of the securities that are the subject of this Prospectus. Investors should make their own assessment as to the suitability of investing in the securities.

The Company has furnished the information in this Prospectus.

The information contained herein is current as of the date hereof and subject to change, completion and amendment without notice. In accordance with Article 23 of the Prospectus Regulation, significant new factors, material mistakes or material inaccuracies relating to the information included in this Prospectus, which may affect the assessment of the Shares and which arises or is noted between the time when the Prospectus is approved by the Norwegian FSA and the listing of the Shares on Oslo Børs, will be mentioned in a supplement to this Prospectus without undue delay. Neither the publication nor distribution of this Prospectus, nor the sale of any Shares, shall under any circumstance imply that there has not been any change in the Group's affairs or that the information herein is correct as of any date subsequent to the date of this Prospectus.

No person is authorized to give information or to make any representation concerning the Group or in connection with the Shares other than as contained in this Prospectus. If any such information is given or made, it must not be relied upon as having been authorized by the Company or by any of the affiliates, representatives, advisers or selling agents of any of the foregoing.

Neither the Company or any of their respective affiliates, representatives, advisers or selling agents, is making any representation, express or implied, to any acquirer of the Shares regarding the legality of an investment in the Shares. Each investor should consult with his or her own advisors as to the legal, tax, business, financial and related aspects of a purchase of the Shares.

Investing in the Shares involves a high degree of risk. See Section 2 "Risk factors".

4.2. Presentation of financial and other information

4.2.1. Financial information

On 25 February 2022, the Group will have completed a Redomiciliation from Australia to Norway through an Australian Scheme of Arrangement, which involes establishing a new entity (being the Company) for the purposes of carrying out the Share Swap whereby shares in PetroNor E&P Ltd. (previously listed on Euronext Expand) ("**PetroNor Australia**") were swapped for shares in the Company. The shares in PetroNor Australia were delisted in conjunction with the listing of the Company. As such, and under the Australian Scheme of Arrangement, all of the shares held by PetroNor Australia's shareholders were transferred to the Company (being PetroNor E&P ASA. The shareholders are thus, in all material respects, identical before and after the transaction. Therefore this will be treated as a continuance of business under the Company (being the new listing entity). The financial statements for the Company going forward will be presented as a continuance of the activities of the Australian company PetroNor Australia. The financial statements of PetroNor Australia have been prepared on the assumption that the Group will continue as a going concern with the realisation of assets and settlement of debt in normal operations. Financial statements will continue to be prepared in compliance with the International Financial Reporting Standards ("**IFRS**") as adopted by the European Union and issued by the International Accounting Standards Board (IASB), and in accordance with the requirements of applicable Norwegian laws.

The Company has prepared audited interim financial statements for the 1 month period ending on 31 October 2021 (the "**PetroNor Norway Financial Statements**") in accordance with IFRS as adopted by the European Union as well as Norwegian disclosure requirements pursuant to the Norwegian Accounting Act. BDO AS, being a member firm of BDO International with registered address at Munkedamsveien 45, Vika Atrium, N-0250 Oslo, has audited the PetroNor Norway Financial Statements. The PetroNor Norway Financial Statements have been incorporated by reference into this Prospectus, and further details are set out in Section 17.5 "Incorporation by reference".

The previous ultimate company of the Group prior to the Redomiciliation, PetroNor Australia, has prepared unaudited consolidated interim financial statements for the six month period ended 30 June 2021 with comparable figures for the same period of 2020 (the "**Interim Financial Statements**"), in accordance with IAS 34 Interim Financial Reporting ("**IAS 34**"), and audited financial statements as of and for the years ended 31 December 2020, 2019 and 2018 (the "**Financial**

Statements", and together with the Interim Financial Statements and PetroNor Noway Financial Statements, the "**Financial Information**") in accordance with IFRS, all included hereto in Appendix B to E.

BDO Audit (WA) Pty Ltd (together with BDO AS, "**BDO**"), a member firm of BDO International Ltd, 38 Station Street, Subiaco, Western Australia 6008, being a Chartered Firm with the Institute of Chartered Accountants Australia, have audited the Financial Statements. The auditor's report for the annual financial statements of 2019 and 2018, respectively, contained a "Material uncertainty related to going concern" with the following wording:

"*We draw attention to Note 2 in the financial report which describes the events and/or conditions which give rise to the existence of a material uncertainty that may cast significant doubt about the Group's ability to continue as a going concern and therefore the Group may be unable to realise its assets and discharge its liabilities in the normal course of business. Our opinion is not modified in respect of this matter.*"

BDO have not audited, reviewed or produced any report or any other information provided in this Prospectus.

In addition to the Financial Information, the annual accounts for the financial year ended 31 December 2018 for PetroNor Cyprus (as defined below) have been incorporated into this Prospectus by reference, as further set out in Section 17.5 "Incorporation by reference".

4.2.2. Industry and market data

In this Prospectus, the Group has used industry and market data from independent industry publications and market research as set out in footnotes to section 7 "Industry and Market Overview" and 8 "Business of the Group" and other publicly available information. While the Group has compiled, extracted and reproduced industry and market data from external sources, the Group has not independently verified the correctness of such data. Unless otherwise indicated, such information reflects the Group's estimates based on analysis of multiple sources, including data compiled by professional organizations, consultants and analysts and information otherwise obtained from other third party sources, such as annual financial statements and other presentations published by listed companies operating within the same industry as the Group may do in the future. Unless otherwise indicated in the Prospectus, the basis for any statements regarding the Group's competitive position in the future is based on the Groups' own assessment and knowledge of the potential market in which it operates.

The Group confirms that where information has been sourced from a third party, such information has been accurately reproduced and that as far as the Group is aware and is able to ascertain from information published by these third party providers, no facts have been omitted that would render the reproduced information inaccurate or misleading. Where information sourced from third parties has been presented, the source of such information has been identified. The Group does not intend, and does not assume any obligations to update industry or market data set forth in the Prospectus.

Industry publications or reports generally state that the information they contain has been obtained from sources believed to be reliable, but the accuracy and completeness of such information is not guaranteed. The Group has not independently verified and cannot give any assurances as to the accuracy of market data contained in this Prospectus that was extracted from these industry publications or reports and reproduced herein. Market data and statistics are inherently unpredictive and subject to uncertainty and not necessarily reflective of actual market conditions. Such statistics are based on market research, which itself is based on sampling and subjective judgments by both the researchers and the respondents, including judgments about what types of products and transactions should be included in the relevant market.

The Group cautions prospective investors not to place undue reliance on the above mentioned data. Unless otherwise indicated in the Prospectus, any statements regarding the Group's competitive position are based on the Company's own assessment and knowledge of the market in which it operates.

As a result, prospective investors should be aware that statistics, data, statements and other information relating to markets, market sizes, market shares, market positions and other industry data in this Prospectus (and projections, assumptions and estimates based on such information) may not be reliable indicators of the Group's future performance and the future performance of the industry in which it operates. Such indicators are necessarily subject to a high degree of uncertainty and risk due to the limitations described above and to a variety of other factors, including those described in Section 2 "Risk Factors" and elsewhere in this Prospectus.

4.2.3. Other information

In this Prospectus, all references to "NOK" are to the lawful currency of Norway, all references to "EUR" are to euro, the single currency of member states of the EU participating in the European Monetary Union having adopted the euro as its lawful currency and all references to "USD" are to the lawful currency of the United States of America.

The Company has NOK as functional currency and the PetroNor Norway Financial Statements are presented in NOK. The reporting currency for the Group is USD and the Financial Statements are presented in USD. Assets and liabilities denominated in a currency other than the functional currency are translated into the functional currency using the period-end exchange rates, and revenues and expenses denominated in other than the functional currency are translated using the actual exchange rate at the time of the transaction. Net gains and losses arising on transactions are included in the consolidated statements of operations.

4.2.4. Rounding

Certain figures included in this Prospectus have been subject to rounding adjustments (by rounding to the nearest whole number or decimal or fraction, as the case may be). Accordingly, figures shown for the same category presented in different tables may vary slightly. As a result of rounding adjustments, the figures presented may not add up to the total amount presented.

4.2.5. Alternative performance measures (APMs)

In this Prospectus, the Company presents certain alternative performance measures ("**APMs**"), including EBITDA and Net Interest Bearing Debt. The APMs are not measurements of performance under IFRS or other generally accepted accounting principles, and investors should not consider any such measures to be an alternative to (a) operating revenues or operating profit (as determined in accordance with IFRS or other generally accepted accounting principles), as a measure of the Group's operating performance; or (b) any other measures of performance under generally accepted accounting principles. The APMs presented herein may not be indicative of the Group's historical operating results, nor are such measures meant to be predictive of the Group's future results.

The Group believes that the APMs described herein are commonly reported by companies in the markets in which it competes and are widely used by investors in comparing performance on a consistent basis without regard to factors such as depreciation and amortisation, which can vary significantly depending upon accounting measures (particularly when acquisitions have occurred), business practice or external and non-operating factors. Accordingly, the Group discloses the APMs presented herein to permit a more complete and comprehensive analysis of the Group's operating performance relative to other companies across periods, and of the Group's ability to service its debt. Because companies calculate APMs differently, the APMs presented herein may not be comparable to similarly titled measures used by other companies.

The Group defines **"EBITDA"** as earnings before interest, taxes, depreciation, and amortisation. The Group presents EBITDA to provide useful supplemental information for understanding the underlying profit generation in the Group's operating activities and for comparing the Group's operating performance with that of other companies in the industry.

The Group defines "**Net Interest Bearing Debt**" or "**NIBD**" as interest bearing borrowings (including interest bearing liabilities and lease liabilities as presented in the statement of the financial position of the Group) less cash and cash equivalents. The Group presents Net Interest Bearing Debt because Management considers it a useful indicator of the Group's indebtedness, financial flexibility and capital structure.

4.3. Cautionary note regarding forward-looking statements

This Prospectus includes forward-looking statements that reflect the Company's current views with respect to future events and anticipated financial and operational performance. These forward-looking statements may be identified by the use of forward-looking terminology, such as the terms "anticipates", "assumes", "believes", "can", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "should", "will", "would" and, in each case, their negative, or other variations or comparable terminology. These forward-looking statements are not historic facts. They appear, among other areas, in the following sections in this Prospectus, Section 7 "Industry and Market Overview", Section 8 "Business of the Group", Section 9 "Selected financial and other information", and Section 11 "Operating and Financial Review", and include statements regarding the Company's intentions, beliefs or current expectations concerning, among other things, financial strength and position of the Group, operating results, liquidity, prospects, growth, the implementation of strategic initiatives, as well as other statements relating to the Group's future business development and financial performance, and the industry in which the Group operates.

Prospective investors in the Shares are cautioned that forward-looking statements are not guarantees of future performance and that the Group's actual financial position, operating results and liquidity, and the development of the industry in which the Group operates, may differ materially from those made in, or suggested by, the forward-looking statements contained in this Prospectus. The Company cannot guarantee that the intentions, beliefs or current expectations upon which its forward-looking statements are based will occur.

By their nature, forward-looking statements involve, and are subject to, known and unknown risks, uncertainties and assumptions as they relate to events and depend on circumstances that may or may not occur in the future. Because of these known and unknown risks, uncertainties and assumptions, the outcome may differ materially from those set out in the forward-looking statements. Important factors that could cause those differences include, but are not limited to:

- the competitive nature of the business and industry the Group operates in and the competitive pressure and changes to the competitive environment in general, including changes in the demand and prices for the Group's products;
- implementation of the Group's strategies;
- earnings, cash flow, dividends and other expected financial results and conditions;
- inaccuracy relating to estimates or calculations of costs on large projects;
- failure by counterparties to meet their obligations;
- failure to attract, retain and motivate qualified personnel;
- increases in labor cost;
- legal proceedings;
- damage to the Group's reputation and business relationships;
- fluctuations of interest and exchange rates;
- changes in general economic and industry conditions, including changes to tax rates and regimes;
- political, governmental, social, legal and regulatory changes;
- access to funding; and
- operating costs and other expenses

The risks that could affect the Group's future results and could cause results to differ materially from those expressed in the forward-looking statements are discussed in Section 2 "Risk Factors".

The information contained in this Prospectus, including the information set out under Section 2 "Risk Factors", identifies additional factors that could affect the Group's financial position, operating results, liquidity and performance. Prospective investors in the Shares are urged to read all sections of this Prospectus and, in particular, Section 2 "Risk Factors" for a more complete discussion of the factors that could affect the Group's future performance and the industry in which the Group operates when considering an investment in the Group.

These forward-looking statements speak only as at the date on which they are made. The Group undertakes no obligation to publicly update or publicly revise any forward-looking statement, whether as a result of new information, future events or otherwise. All subsequent written and oral forward-looking statements attributable to the Group or to persons acting on the Company's behalf are expressly qualified in their entirety by the cautionary statements referred to above and contained elsewhere in this Prospectus.

5. REASONS FOR THE LISTING

Subject to certain customary conditions, Oslo Børs has approved the listing of the Shares with commencement of trading in the Shares on Oslo Børs exepected on or about 28 February 2022. The Company believes that the Listing and Redomiciliation, inter alia, will:

- further enhance the Group's profile with investors, business partners, suppliers and customers;
- allow for a more liquid market for the Shares;
- facilitate for a more diversified shareholder base and enable additional investors to take part in the Group's future growth and value creation;
- enable the Company to implement stock based incentive schemes for the Management and employees;
- streamline the Group's corporate structure and reduce corporate overheads have not yet been executed.
- provide better access to capital markets; and
- further improve the ability of the Group to attract and retain key management and employee.

6. DIVIDENDS AND DIVIDEND POLICY

6.1. Dividend policy

In deciding whether to propose a dividend and in determining the dividend amount, the Board of Directors will comply with the legal restrictions set out in the Norwegian Public Limited Liabilities Companies Act of 13 June 1997 no. 45 (the "**Norwegian Public Limited Liability Companies Act**") (see Section 6.2 "Legal constraints on the distribution of dividends") and take into account the Company's capital requirements, including capital expenditure requirements, the Company's financial condition, general business conditions and any restrictions that its contractual arrangements in place at the time of the dividend may place on its ability to pay dividends and the maintenance of appropriate financial flexibility. Except in certain specific and limited circumstances set out in the Norwegian Public Limited Liability Companies Act, the amount of dividends paid may not exceed the amount recommended by the Board of Directors.

The proposal to pay a dividend in any year is, in addition to the legal restrictions set out in Section 6.2 "Legal constraints on the distribution of dividends", further subject to any restrictions in the Company's borrowing arrangements or other contractual arrangements in place at the time.

Further, the tax legislation of an investor's Member State and of the Company's country of incorporation (Norway) may have an impact on the income received from the Shares, see Section 16 "Taxation".

The Company’s objective is to create lasting value and provide competitive returns to its shareholders through profitability and growth and long-term returns to shareholders in the form of increased share price as well as dividends. Dividends are assumed to arise in line with the growth in the Company’s results while at the same time recognizing the opportunities for adding value through new profitable investments.

Neither the Company, nor the previous parent company prior to the Redomiciliation, has paid any dividends on its Shares during the financial years ended 31 December 2020, 2019 and 2018.

6.2. Legal constraints on the distribution of dividends

Dividends may be paid in cash, or in some instances as dividends in kind. The Norwegian Public Limited Liability Companies Act provides the following constraints on the distribution of dividends applicable to the Company:

- section 8-1 of the Norwegian Public Limited Liability Companies Act provides that the Company may distribute dividends to the extent that the Company's net assets following the distribution are sufficient to cover (i) the Company's share capital, (ii) the Company's reserve for valuation variances and (iii) the Company's reserve for unrealised gains. Any receivables of the Company which are secured through a pledge over the Company's Shares and the aggregate amount of credit and security which, pursuant to sections 8-7 through to 8-10 of the Norwegian Public Limited Liability Companies Act fall within the limits of distributable equity are to be deducted from the distributable amount;

- the calculation of the distributable equity shall be made on the basis of the balance sheet included in the approved annual accounts for the previous financial year, provided, however, that the registered share capital as at the date of the resolution to distribute dividends shall be applied. Following approval of the annual accounts for the last financial year, the General Meeting may also authorise the Board of Directors to declare dividends on the basis of the Company's annual accounts. Dividends may also be resolved by the General Meeting based on an interim balance sheet which has been prepared and audited in accordance with the provisions applying to the annual accounts and with a balance sheet date no older than six months before the date of the General Meeting's resolution; and

- dividends can only be distributed to the extent that the Company's equity and liquidity following the distribution is considered sound in light of the risk and scope of the Company's business.

The Norwegian Public Limited Liability Companies Act does not provide any time limit after which entitlement to dividends lapses. Subject to various exceptions, Norwegian law provides a limitation period of three years from the date on which an obligation is due. There are no dividend restrictions or specific procedures for non-Norwegian resident shareholders to claim dividends. For a description of withholding tax on dividends applicable to non-Norwegian residents, see Section 16 "Taxation".

6.3. Manner of dividend payments

Any future payments of dividends to all holders of the shares (including non-resident shareholders) will be made in the currency of the bank account of the relevant shareholder registered with the VPS, either through a nominee account or a personal VPS registered account, and will be paid to the shareholders through the VPS. Shareholders registered in the VPS who have not supplied the VPS with details of their bank account, will not receive payment of dividends unless they register their bank account details with the Company's VPS registrar being DNB Bank ASA with registered address at Dronning Eufemias gate 30, N-0191 Oslo (the "**VPS Registrar**"), and transfer fees may apply for payments made in such manner. The exchange rate(s) that is applied when denominating any future payments of dividends to the relevant shareholder's currency will be the exchange rate of the relevant bank on the payment date. Dividends will be credited automatically to the VPS registered shareholders' accounts, or in lieu of such registered account, at the time when the shareholder has provided the VPS Registrar with their bank account details. Shareholders' right to payment of dividend will lapse three years following the resolved payment date in favour of the Company for those shareholders who have not registered their bank account details with the VPS Registrar.

7. INDUSTRY AND MARKET OVERVIEW

The information in the market and industry section has been sourced from various independent market research, industry publications and other public available information, as well as from the company's internal estimates which are based on analysis of multiple sources, including data compiled by professional organizations, customer feedback, and information otherwise obtained from other third-party sources. Key third-party sources used include the 2019, 2020 and 2021 annual statistical review of world energy by BP plc ("BP"), the energy outlook by BP for 2020, the annual energy outlook 2021 by US Energy Information Administration (the "EIA") outlook report, the world fact book by the Central Intelligence Agency of USA (the "CIA Fact Book") and COP26 UN Climate Change Conference material. The company have compiled, extracted and reproduced data from external sources but have not independently verified the correctness of such data. However, the company confirm that information from third parties has been accurately reproduced and that, to its knowledge, no facts have been omitted that would render the reproduced information inaccurate or misleading.

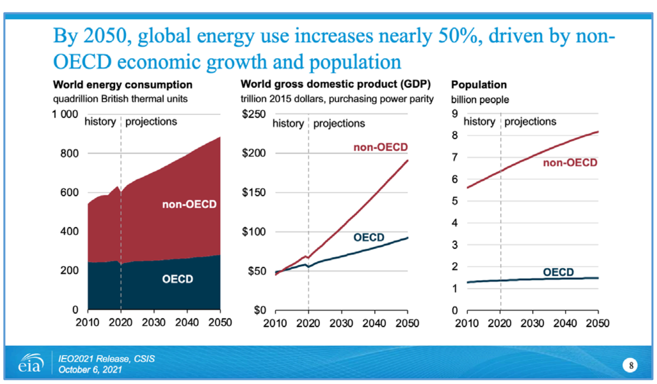
7.1. The global energy market[1] [2]

The global energy demand continues to grow driven by an increase in the global population combined with prosperity and increasing living standards in the emerging world, however unfortunately we expect that significant inequalities in energy consumption and access to energy will persist. The structure of energy demand as we see it today is likely to change over time with a declining role of fossil fuels, offset by an increasing share of renewable energy and a growing role for electricity. These changes impact the predictions of the change in energy demand and energy sources and thus the expected use of oil and gas going forward.

A transition towards a lower carbon energy system is likely to lead to fundamental restructuring of the global energy system, with a more diverse energy mix, greater consumer choice, more localized energy markets, and increasing levels of integration and competition. These changes underpin core expectations about how the global energy system may develop in a low-carbon transition. Demand for oil is expected to be reduced over the next 30 years according to BP. The scale and pace of this decline is driven by the increasing efficiency and electrification of road transportation combined with the growth in other energy forms and a transition towards use of hydrogen or batteries as energy media. The outlook for natural gas is more resilient than for oil, underpinned by the role of natural gas in supporting fast growing developing economies as they decarbonized and reduce their reliance on coal, and as a source of near-zero carbon energy when combined with carbon capture.

World energy consumption has steadily increased since the industrial revolution, a trend which is expected to continue in the medium term. As per EIA, fossil fuels continue to supply more than 85 percent of the world's energy - oil is the largest energy source, meeting 34 percent of the world's energy consumption, while natural gas accounts for 23 percent and coal for 28 percent.

The world consumption of primary energy, including oil, natural gas, coal, nuclear, hydro power and other renewable energy, is, by EIA, expected to increase by 50% within 2050. With the largest growth in population and in gross domestic product to be in the non-OECD countries.



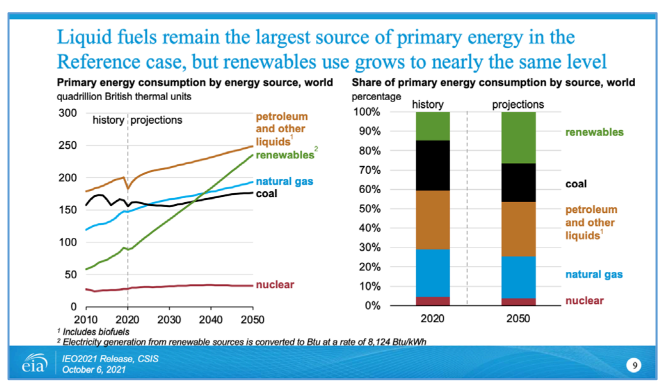


Figure 7.1.1 Prediction of the Global Energy increase from 2020 to 2050 - International Energy Outlook by EIA, October 6th 2021, p. 8 & 9

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[1] Source : BP – Energy Outlook 2020 Edition p.3-6
[2] Source : EIA - International Energy Outlook, October 6th 2021, p. 8, 9

7.2. Key trends and drivers in the oil and gas exploration and production markets[3] [4]

We expect that the oil and gas exploration and production markets will be highly impacted by the drive towards a lower carbon system - which may fundamentally restructure and reshape the global energy system. The political agenda has changed significantly the last two years and the COP26 conference will further guide the world in a direction towards the 2050 goal of de-carbonizing the word economy. Key elements in the drivers for the oil and gas markets are

- A Political decision to keep the world average temperature below the 2.0 centigrade goal and target for reaching a 1.5 centigrade goal

- A shift away from traditional hydrocarbons (oil, natural gas and coal) towards non-fossil fuels, led by renewable energy. In some scenario by BP, non-fossil fuels account for the majority of global energy from the early 2040s onwards, with the share of hydrocarbons in global energy more than halving over the next 30 years.

- A diversified energy mix - for much of history, the global energy system has tended to be dominated by a single energy source. For the first half of the previous century, coal provided most of the world's energy. As the importance of coal declined, oil became the predominant energy source. With the energy transition over the next 20 years, the global fuel mix may be far more diversified than previously seen, with oil, natural gas, renewables and coal (for a time) all providing material shares of world energy. The greater variety of fuels may imply that the fuel mix could be driven by customer choice rather than the availability of fuels

- An implementation of electricity and hydrogen as carriers of energy in the transportation sector

There is a significant discrepancy between the predictions in the production and use of hydrocarbon between different agencies as exemplified by the BP Energy outlook from 2020. BP operates with three significantly different scenario (a) continue with business as usual (b) targeting a net zero emission of CO2 within 2050 and (c) a rapid reduction in use of hydrocarbons scenario as displayed in figure 7.2.2.

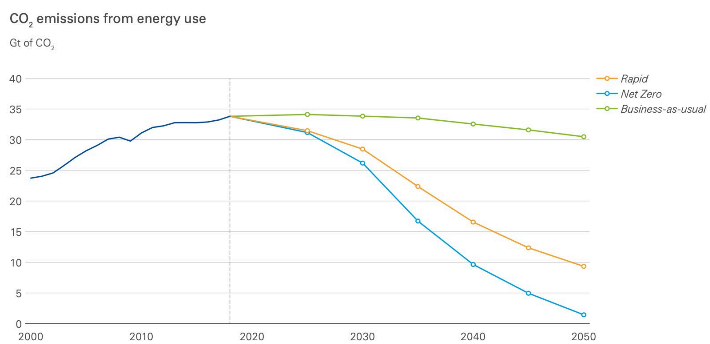


Figure 7.2.2 CO2 emissions from energy use a per the BP Energy outlook 2020

7.3. Competitive landscape

The oil is being sold at an international marketplace, normally linked to the Brent oil price with a quality discount or premium. Gas however, unless converted into liquified natural gas, will be sold in a local or regional market, thus there is two distinct pricing mechanisms for oil and gas. Going forward there is large uncertainties in the predictions for both the oil and gas prices.

7.3.1. Oil prices

With the severe drop in oil price at start of Covid-19 combined with international oil companies retracting back to their home markets, a drop in investment in the oil and gas industry has been experienced since 2019[5]. EIA predicts a flattening in the demand for petroleum products, however that from 2020 and up to 2050 we may see an increasing oil price[6]. What is

[3] Source: BP - Energy Outlook, 2020, p. 3, 4, 5, 6, 13, 16,17
[4] EIA - International Energy Outlook, October 6th 2021, p. 8, 9
[5] American Petroleum Institute – News blog 17th Sep. 2021 by Dean Foreman
[6] EIA - International Energy Outlook, October 6th 2021, p.5, 6

implicit, is that the market going forward is very difficult to predict and that the industry should be prepared for a significant volatility going forward.

For Africa, being the core region of the Group, we expect the international oil companies to withdraw to some extent which may open a market opportunity for small and mid-sized companies.

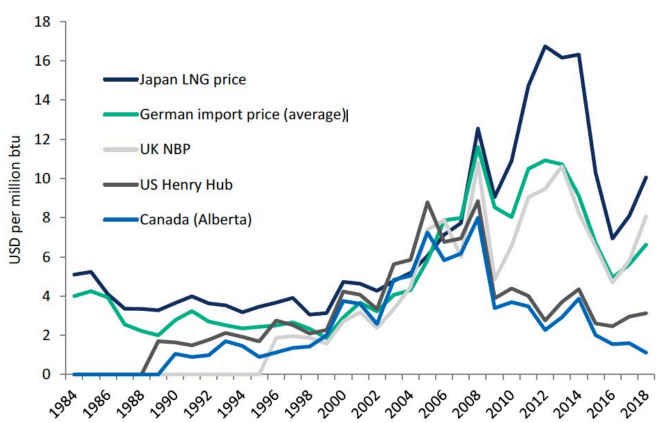
Figure 7.3.1.1 – Brent oil price, daily from 1 January 2000 to 6 November 2021 (source EIA online data-base)

7.3.2. Gas prices

Because gas is not easily transported, gas prices are normally not determined by a world-wide market. Gas prices are usually determined regionally, with regions defined by pipeline and LNG transportation networks. Hence, regional gas prices generally correlate less than the prices for various types of oil, however gas prices are frequently also impacted by the price of other energy sources, such as the oil price.

Financing of an onshore gas development project in our main market Africa has historically been difficult due to lack of bankable contract parties. However, going forward, it is expected that gas will be required as a transition fuel for Africa for the coming decade and if so, it may ease the issues related to financing of the development of such gas projects.

Each country may have its own gas market and in Nigeria for example, long term fixed price contracts would be expected around 3 ±1 US$/ MMBtu[7] corrected for annual inflation whilst LNG and the European gas historically has been more linked to the oil or product prices[8].



Source: BP Statistical Review of World Energy June 2019.

7.3.3. Republic of Congo[9]

The Republic of Congo holds a significant potential with nearly 3.8 bn boe of remaining resources and has a current oil production of around 300,000 barrels of oil per day ("**Bopd**" or "**bopd**") and is thus the third largest oil producer in Sub-Saharan Africa. The two dominant players in the country is TotalEnergies and ENI which jointly operate above 70% of the

[7] Company internal assessment
[8] BP – Statistic review of World Energy, 2019, 68th edition
[9] Wood Mackenzie, Republic of Congo Upstream Summary August 2021

country's production. The national oil company, Société National des Petrol du Congo (SNPC) plays a key role in managing the states share in upstream developments.

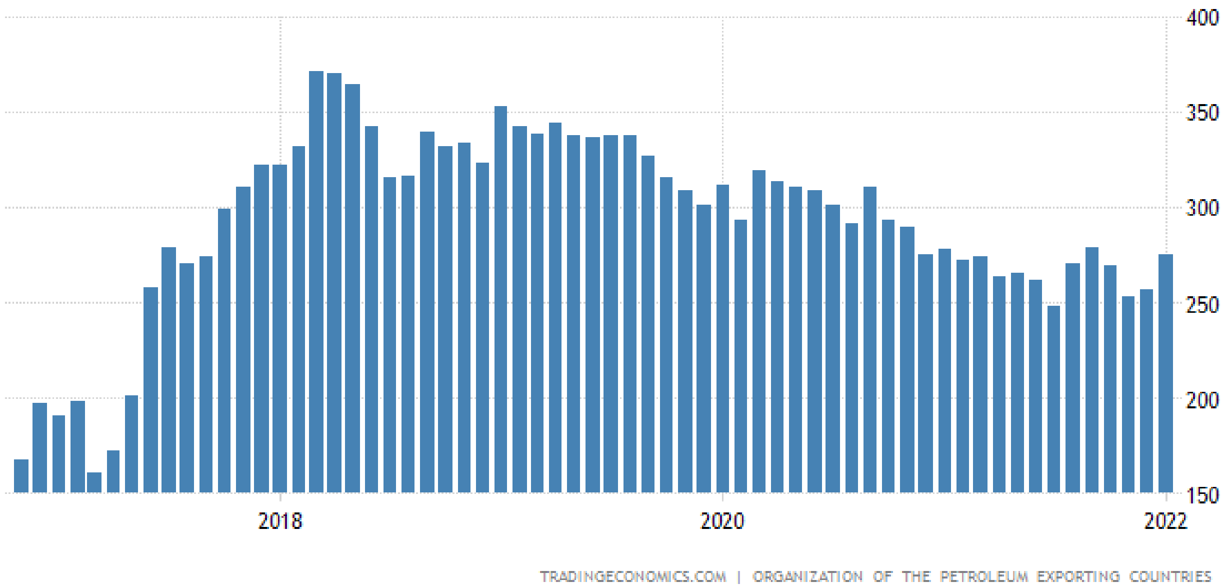


Figure 7.3.3.1 – Last 5 years' average oil production rate in the Republic of Congo, 1000s bopd (figure source Tradingeconomics.com - data sourced from Organisation of the Petroleum Exporting Countries)

7.3.4. Nigeria[10] [11]

Nigeria holds a significant potential with 37 bn bbl of remaining oil resources and has a current oil production of around 1,900,000 bopd and is thus the largest oil producer in Africa. In addition, Nigeria has a gas production of 8 bcf/day of which 70% is used for LNG or for domestic consumption. There are significant changes in the Nigerian oil industry with the supermajors such as Shell and Exxon are divesting large shares of their historical portfolios. During 2021, militancy rose again.

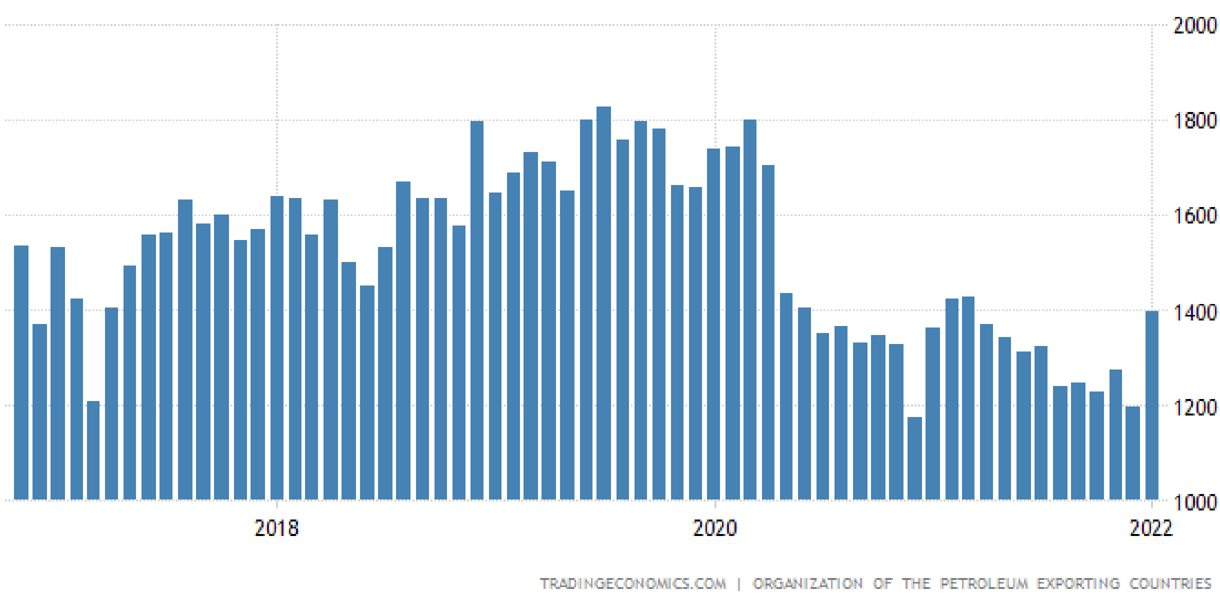


Figure 7.3.4.1 – Last 5 years average oil production rate in Nigeria, 1000s bopd (figure source Tradingeconomics.com - data sourced from Organisation of the Petroleum Exporting Countries)

[10] Wood Mackenzie, Nigeria Upstream Summary October 2021
[11] Nigeria fact page, Organization of oil exporting countries

7.3.5. The Gambia[12] [13]

There is currently no oil or gas production in The Gambia. Currently one exploration well is being drilling in the country in Block A2 and the country has announced an exploration license round for Block A1.

7.3.6. Guinea-Bissau[14]

There is currently no oil or gas production in Guinea-Bissau.

7.3.7. Senegal[15]

Senegal has had multiple discoveries of oil and gas since 2014 and holds today in excess of 6 bn bbl of resources. The first oil field to come onstream, the Sangomar field, is expected to come on stream in 2023 and to reach a plateau production of 100.000 bopd within 1 – 2 years.

7.4. Regulatory environments relating to the Group and its business

The Group is subject to specific legal and environmental regulations relating to the oil industry, which in turn is specific to the country of operations and are described in more detail for the actual licenses held by the Group in Section 8.3 "Legal framework for petroleum business". Set out below is various other regulatory environments relating to the Group and its business.

7.4.1. Data protection regulations

The Group is subject to GDPR and local data privacy laws in the countries the Group operates in, and has implemented data protection procedures and systems to comply with these laws and regulation. The personal data handled by the Group is mainly limited to its responsibilities as an employer and through handling of customer information. This makes the Group exposed to data protection and data privacy laws and regulations it must comply with, which all imposes stringent data protection requirements and could impose penalties for noncompliance, related to storing, sharing, use, controlling, disclosure and protection of personal information and other user data on its platforms.

7.4.2. Tax

In the extractive industry in general, being the industry the Group operates in, the terms for each license are defined by individual agreements. The taxation of extraction of oil and gas production is normally structured as a combination of royalty and profit tax, together constituting the majority of the tax payable by the license holder. As the taxes in the extractive industry are normally excessive compared to ordinary income tax level in the respective country, the ordinary country income tax is normally replaced by the taxes and royalties defined under the fiscal terms of the license agreement. Section 8.3 "Legal framework for petroleum business" and Section 8.4 "Licenses and concessions" outlines the details of the tax regime and the fiscal terms valid for each of the exploration and production licenses held by the Group.

The Group is subject to prevailing tax laws in each jurisdiction the Group operates and will be subject to changes in tax laws, tax treaties or regulations or the interpretation or enforcement thereof in the various jurisdictions, possibly with retrospective effect. The Group has established and conducts operations through internationally based subsidiaries and through project related permanent establishments. Procedures and actions are implemented in the Group to adhere to applicable tax laws wherever the Group is present and conducts its operations. The Group's overall tax charge is dependent on where profits are generated and taxed, where the respective jurisdictions have different tax systems and tax rates.

7.4.3. Labour and employment, and health and safety laws

The Group is subject to labour and employment laws, health and safety laws and other regulations with respect to the international operations. With offices and PetroNor representatives in the Republic of Congo, Guinea-Bissau, The Gambia, Senegal, UK, Sweden, Cyprus and UAE, the Group must coordinate the multiple legal jurisdictions with a geographically and culturally diverse workforce. Where PetroNor acts as the operator for the licence partnerships in Guinea-Bissau, The Gambia, and Senegal, PetroNor must ensure that any subcontractors also adhere to the local rules.

The Group monitors the changes in applicable laws and regulations and believe that the Company in all material aspects is compliant with applicable laws and regulations.

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[12] CIA – Online World Fact Book, The Gambia
[13] Announcement by the Ministry of Petroleum, The Gambia, November 8th 2021
[14] CIA – Online World Fact Book, Guinea-Bissau
[15] Wood Mackenzie, Senegal upstream Summary, August 2021

7.4.4. International sanctions, export/import control and anti-money-laundering laws and regulations

The Group's international operations makes the Group exposed towards international sanctions laws and regulations, in particular sanctions on trade and import/export, and anti-money laundering laws through its operations in and trade across multiple jurisdictions. Furthermore, sanctions imposed on certain countries, companies or individuals by international and regional bodies including those administered by the United Nations, the European Union and the U.S. Office of Foreign Assets Control could materially adversely affect the Group's ability to establish its operations in or trade with sanctioned countries or companies and/or individuals linked with such countries. The Group has policies, procedures and processes in place that aim to ensure that any cross-border transfer of people, products, services, technology and funds are properly screened against all relevant sanctions lists and programs, as well as procedures to prevent and detect red flags related to sanctions, export controls, money laundering and terrorist financing.

7.4.5. Anti-bribery/anti-corruption laws and regulations

Operating an international business requires PetroNor to uphold all laws relevant to countering bribery and corruption in each of the jurisdictions that it operates. PetroNor representatives are bound by the most stringent requirements of these laws in respect of their conduct in all jurisdictions, even if such conduct is otherwise permissible by the local law of a particular jurisdiction. Currently PetroNor perceives the UK Bribery Act legislation to impose the most stringent requirements. The Group is of the view that it has the necessary governance and implemented procedures in place to work in a manner that mitigates the corruption risks associated with delivery of services in the areas that the Group operates. See however above in Section 2.1.2 "The Group operates in countries with a high risk of corrupt practices".

8. BUSINESS OF THE GROUP

8.1. Introduction to PetroNor E&P ASA

PetroNor E&P ASA is an independent, African focused oil and gas exploration and production company based in Norway.

The key strategy of the Group is, in addition to developing existing assets and organic growth, to acquire additional oil and gas licences and pursue acquisition opportunities, the Group continuously considers such opportunities.

8.1.1. Overview of assets

The Company holds exploration and production assets in Africa through subsidiaries and joint ventures, namely the offshore PNGF Sud production licenses in the Republic of Congo, (through its subsidiary HEPCO), the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licenses offshore Guinea-Bissau (through its subsidiary PetroNor E&P AB (previously SPE Guinea Bissau AB[16])), the A4 license offshore The Gambia (through its wholly owned subsidiary PetroNor E&P Gambia Ltd). The Company reserves its rights to the Rufisque Offshore Profond and Senegal Offshore Sud Profond licences offshore Senegal (through its subsidiary African Petroleum Senegal Ltd), which are currently in arbitration (see section 8.2.5 "Senegal – Rufisque Offshore Profond and Senegal Offshore Sud Profond"). Further, subject to the successful completion of the Aje Transaction (as further described in Section 8.2.6), the Group will hold indirect interests in the OML-113 which includes the Aje Field offshore Nigeria through its subsidiary special purpose vehicle, Aje Production AS (transaction pending completion). Please refer to Figure 8.1.1.1 showing the location of the assets described.

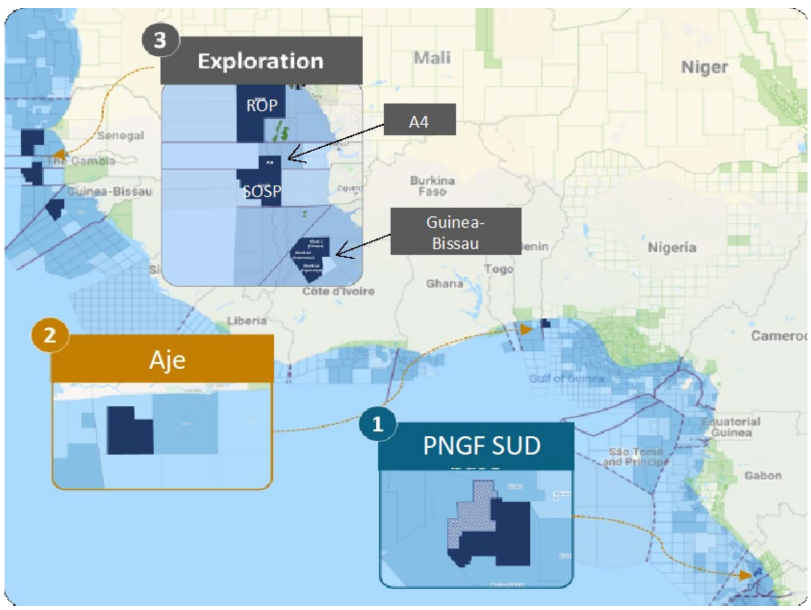

Figure 8.1.1.1 Map of the Group portfolio

8.1.2. Congo assets

PetroNor E&P's indirect subsidiary, HEPCO, holds a 20% (16.83% net to PetroNor) non-operated interest in the PNGF Sud licenses offshore Congo. PetroNor owns 84.15% of HEPCO. The operator of the licenses is Perenco which holds a 40% interest in the PNGF Sud licenses. PetroNor participated in the 2016 tender process held by the Ministry of Hydrocarbons following which HEPCO subsequently became a license partner as of 1 January 2017. The PNGF Sud fields are located approximately 25 km off the coast of Pointe-Noire in water depths of 80 to 100 metres. PNGF Sud comprises of three (3) production license agreements (Tchibouela II, Tchendo II and Tchibeli-Litanzi II), which contain five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi. Initially discovered in 1979, PNGF Sud commenced production in 1987 and produces from about 60 wells. Following the establishment of the new licence group in 2017, significant operational improvements have been made, increasing gross production from approx. 15,000 bopd in January 2017 to an average of 22,713 Bopd in 2020. The 2P reserves attributed to the Group's reserves are estimated to 20.73 million units of barrels of oil equivalents ("**MMboe**"), ref. Section 8.2.1.

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[16] As of 4 June 2021, SPE Guinea Bissau formally changed its name to PetroNor E&P AB.

Further, through an umbrella agreement related to the award of PNGF Sud licence, the licence partners of PNGF Sud have the right to negotiate the licence terms for entering into a production sharing contract for the PNGF Bis license. The PNGF Bis licence covers an area located to the North-West of the PNGF Sud licences and contains contingent resources with a prospect of being developed through a tie-back to the facilities on the PNGF Sud fields. The management remains positive in terms of negotiating and signing a production sharing contract for the PNGF Bis license with the relevant governmental bodies, but no assurance can be given as to whether the Group will be able to agree terms satisfactory to the Group. Furthermore, if the Group is able to secure entry into a production sharing contract, the Group expects to be granted a 23.6% indirect interest in the PNGF Bis again, however, no assurances can be given to the potential interest allocated to the Group.

8.1.3. Guinea-Bissau assets

In late 2020, the Group acquired interests in the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences offshore Guinea-Bissau through the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB. The transaction received the required in-country regulatory approvals, published in the Official Gazette of Guinea-Bissau (in Portuguese, *Boletim Oficial*) in late April 2021. Subsequently on 4 May 2021, the Group assumed the operatorship and an interest of 78.57% in the licences. FAR Ltd, an Australian listed company, holds the remaining 22.43% equity in both licences. The offshore licences, covering 4,963 km^2, are located on the highly prospective trend along the coastline of Mauritania, Senegal, Gambia, Guinea-Bissau and Guinea-Conakry. The licence contains two significant prospects, the Atum and Anchova prospects, which have similarities to the world class Sangomar field being developed in Senegal. Further, the Sinapa and Esperança licences have commercially attractive contract terms. The licence partner FAR Ltd was the pioneering company, along with Cairn and ConocoPhillips, which discovered the analogous Sangomar Field in Senegal.

The gross case, mean recoverable, prospective unrisked resources at Atum and Anchova, are estimated at 498 MMbbls. The resource estimate is based on the management expectations of Svenska Petroleum Exploration AB from 2019 made prior to the Group acquiring SPE Guinea Bissau AB and has not been audited by the Company or by any independent third party. The resources are not accounted for in the overview of the Group's reserves in Section 8.2.1. "Reserves and resources".

8.1.4. Gambia assets

In The Gambia, the Group and the Government of The Gambia reached a mutual agreement to settle the arbitration related to the A1 and A4 licenses on 19 September 2020. Under the terms of the settlement agreement, PetroNor E&P Gambia Ltd was awarded the rights to a new 30-year lease for the A4 license comprising approximately 1,376 km^2 after an initial evaluation period of one year. All claims to the A1 licence were relinquished. On 19 October 2021, PetroNor received confirmation from the Government of The Gambia that an additional one-year extension to the initial evaluation period of the A4 licence, until 18 October 2022 had been granted. This will enable the Company to progress with its ongoing discussions with potential partners. There is no minimum work program or spend commitment within the evaluation period.

The sum of the mean net unrisked prospective resources for the A4 licence portfolio are estimated to be approximately 2 billion barrels of oil. This prospective resources estimate is based on the expectations of the management of the Company and has not been audited by any independent third party. These prospective resources are not accounted for in the overview of the Group's reserves in Section 8.2.1. "Reserves and resources".

8.1.5. Senegal assets

The Senegal assets are in arbitration. Please see section 8.2.5 "Senegal – Rufisque Offshore Profond and Senegal Offshore Sud Profond" for more information

In Senegal, African Petroleum Senegal Ltd. reserve its rights to a 90% operated interest in the ROP and SOSP licenses with the National Oil Company, Petrosen, holding the remaining 10%. The Company is in arbitration with the Government of Senegal to protect its interests in the licenses. ROP and SOSP are located offshore Southern / Central Senegal, with a net acreage of 15,796 km^2.

The sum of the mean case, net unrisked prospective resources, for all matured prospects is estimated to be approximately 1.8 billion barrels of oil for both licences. This prospective resources estimate is based on the ERC Equipoise 2015 CPR completed for African Petroleum Corporation Limited ("**APCL**") and covers both ROP and SOSP licences. These prospective resources are not accounted for in the overview of the Group's reserves in Section 8.2.1. "Reserves and resources".

8.1.6. Nigeria assets

In the second half of 2019, the Company entered into an agreement with Panoro Energy ASA for the acquisition of certain companies holding interests in the OML-113 licence (Aje Field) offshore Nigeria. In addition, the Company established a special purpose vehicle with the license's operator, Yinka Folawiyo Petroleum ("**YFP**"), for the purpose of assuming the lead technical and management role in the next phases of the Aje Field development.

The completion of the transaction was subject to the satisfaction of the approval by the minister of petroleum resources in Nigeria, regulatory approval from the governmental bodies of Nigeria as well as all third party required approvals, such as waiver of any first right of refusal by the existing license partners. Upon the successful completion of the transaction, the Group will acquire an indirect nominal participating interest of 34% in the OML-113 licence and a revenue interest of 24.3% in the OML-113 licence. The obligations to cover operational expenses and capital expenditures deviate from the nominal interests and revenue interests and are described in Section 8.2.6. "Nigeria – OML-113".

The OML-113 licence is located offshore Western Nigeria adjacent to the Benin border and contains the Aje Field as well as a number of exploration prospects. Discovered in 1997 in water depths ranging from 100 m to 1,500 m, the Aje Field began production in 2016 and produces from two wells.

The 2P reserves are estimated to 0.2 MMbbls. The reserves estimate is based on the expectations of the management of the Company and has not been audited by the Company or by any independent third party. The reserves are accounted for in the overview of the Group's reserves in Section 8.2.1. "Reserves and resources".

8.2. The Group's business activities

8.2.1. Reserves and resources

Reserves portfolio

PetroNor's classification of the Group's reserves and resources complies with the guidelines established by the Oslo Stock Exchange and is based on the definitions set by the Petroleum Resources Management System (PRMS-2007), sponsored by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE / PRMS) from 2007 and 2011.

Reserves are the volume of hydrocarbons that are expected to be produced from known accumulations:

- On Production
- Approved for Development
- Justified for Development

Reserves are also classified according to the associated risks and probability that the reserves will be produced.

- 1P – Proved reserves represent volumes that will be recovered with 90% probability
- 2P – Proved + Probable represent volumes that will be recovered with 50% probability
- 3P – Proved + Probable + Possible volumes that will be recovered with 10% probability

Contingent Resources are the volumes of hydrocarbons expected to be produced from known accumulations:

- In planning phase
- Where development is likely
- Where development is unlikely with present basic assumptions
- Under evaluation

Contingent Resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves.

The Group obtained a Competent Persons Report (the "**CPR**") auditing the Reserves (1P, 2P and 3P) and Resources (1C, 2C and 3C) as of 31 December 2020 and covers PNGF Sud and PNGF Bis. This CPR was completed by AGR in March 2021.

The reserves figures are outlined in the table immediately below and cover:

- PNGF Sud (based on the CPR)
- PNGF Bis (based on the CPR but noting that the Group has not secured a production sharing contract for the area)
- Aje Field (based on management expectations and noting that the Aje Transaction has not been completed)

	Net PetroNor reserves (developed or under development)		
	1P Million Boe	**2P** Million Boe	3P Million Boe
16.83% PNGF Sud			
Tchibouela	8.9	**11.07**	13.62
Tchendo	3.55	**4.86**	6.06
Tchibeli	1.25	**2.98**	4.46
Litanzi	1.16	**1.82**	2.27
Subtotal	14.86	**20.73**	26.41
23.56% PNGF Bis			
Loussima (Bis)	-	**-**	-
TOTAL	**14.86**	**20.73**	**26.41**

During the period from 1 January 2020 to 31 December 2020, the total amount of oil produced from PNGF Sud was approx. 8.31 MMbbls with a net production attributed to the Group of approximately. 3,850 Bopd.

Resources

The net contingent resources are outlined in the table immediately below and cover:

- PNGF Sud (based on the CPR)
- PNGF Bis (based on the CPR but noting that the Group has not secured a production sharing contract for the area and therefore neither has secured the legal rights to carry out petroleum activities in respect of PNGF Bis)
- Aje Field (based on management expectations and noting that the Aje Transaction has not been completed and that the Group therefore has not yet acquired the indirect interests in the Aje Field)

	Net PetroNor Contingent Resources (undeveloped)		
	1C Million Boe	**2C** Million Boe	3C Million Boe
16.83% PNGF Sud		**4.29**	
Tchibouela	2.74	**4,29**	6.95
Tchendo	0.91	**1.53**	3.23
Tchibeli	0.99	**1.88**	3.03
Litanzi	-	**-**	-
Subtotal	4.65	**7.71**	13.21
23.56% PNGF Bis			
Loussima (Bis)	5.29	**6.82**	8.45
Total PNGF	9.93	**14.53**	21.66
OML-113			
Aje	-	**18.7**	-
TOTAL	**9.93**	**33.23**	**21.66**

8.2.2. Republic of Congo (Brazzaville) – PNGF Sud and PNGF Bis

Overview and background

PetroNor, through HEPCO, participated in the 2016 tender process with the Congo Ministry of Hydrocarbons for an interest in the PNGF Sud licenses. With effect from 1 of January 2017, HEPCO was awarded a 20% working interest in the PNGF Sud (currently net 16.83% to Group). The National Assembly / Senate formally approved the license contracts in May 2017.

PNGF Sud comprises 3 production sharing contracts (in French, Contrat de Partage de Production or "CPP"): Tchibouela II, Tchendo II and Tchibeli-Litanzi II. The licenses contain five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi, which have been developed as an integrated group named PNGF Sud. The licenses are located approximately 25 km off the coast of Pointe-Noire in water depths of 80-100 metres.

Further, through an umbrella agreement linked to the award of the PNGF Sud licence, the licence partners of PNGF Sud have the right to negotiate the licence terms for the entering into of a production sharing contract for the PNGF Bis licence. The PNGF Bis licence covers an area located to the North-West of the PNGF Sud licences and contains (based on management expectations of reserves as set out in Section 8.2.1) contingent resources with a prospect of being developed through a tie-back to the facilities on the PNGF Sud fields. The management remains positive in terms of negotiating and signing a production sharing contract for the PNGF Bis with the relevant governmental bodies, but no assurance can be given as to whether the Group will be able to agree terms satisfactory to the Group. However, if the Group is able to secure the entry into of a production sharing contract, the Group expects to be granted a 23.6% indirect interest in PNGF Bis but no assurances can be given to the interest allocated the Group.

PNGF Bis is located to the North-West of PNGF Sud and comprises 2 discoveries, Loussima SW and Loussima.

Geological description

Tchibouela Field

Tchibouela Main consists of three Cretaceous aged reservoir formations, the Senonian, Turonian and Cenomanian, with reservoir depths ranging from 300 to 1,000 meter true vertical depth sub-sea ("mTVDSS"). The subsurface structure of the field is a dome formed anticline and the reservoir quality is generally good but varies across the field. The main reservoirs within the Turonian and Cenomanian aged section contain light oil with low gas to oil ratio ("GOR"). The youngest reservoir, the Senonian, contains gas above an oil rim. Tchibouela Main produces from 34 active oil producing wells. The field came on stream in 1987, had its peak production in 1995 and is now on tail end production with a high water-cut. The Cenomanian is an excellent reservoir with a strong aquifer which helps maintain reservoir pressures and supports a high recovery factor. The Turonian has more varying reservoir properties, here also the pressure is maintained by natural water influx supported by one water injector well. There are two gas producing wells within the Senonian reservoir providing gas which is used to generate electricity for offshore operations or compressed and reinjected into the subsurface to support reservoir pressures and increase recovery rates for oil. Since 2017 several well workovers such as re-perforations and artificial lift repairs have been performed to maintain and improve production from the field. The operator plans to continue this programme which is expected to continue to arrest the decline of the production rates and potentially increase production levels going forward. Existing producers are included in the reserves calculation. There is potential for additional infill drilling targeting both the Cenomanian and Turonian reservoir intervals.

Tchibouela East is a similar smaller dome structure to Tchibouela Main, with Turonian and Cenomanian reservoir levels. The field started production in 1998 with 6 oil producing wells. From 2019, production has resumed from this field with a total of 4 wells producing today.

Tchendo Field

Tchendo is an oil field with production from three separate Cretaceous aged reservoir levels, Senonian, Turonian and Cenomanian with reservoir depths from 450 to 750 mTVDSS. The structure is a gentle dome structure similar to Tchibouela and with similar reservoir characteristics. Water depth is 95 m. Tchendo was discovered by exploration well TCDM1 in 1979 and started production in 1991 with peak production reached in 1993. Reservoir pressure has been maintained by partial water injection. Approximately twenty wells are currently producing, of which seven produce from the Senonian interval and thirteen from the Turonian and one well that produces from the Cenomanian reservoir interval. Across the field, the water cut (percentage of total produced reservoir fluids that are water) is high in Turonian but remains low in the Senonian. Production from the Cenomanian interval ceased in 2009 at a recovery factor of 56% however, production was restored in 2019 through one well which currently produces approximately 600 Bopd.

An infill drilling programme has been approved at the Tchendo Field. A 14-slot wellhead platform is to be installed and drilling of the first 7 wells targeting the Senonian and Turonian intervals will take place following completion of a separate infill drilling program at the Litanzi field. The remaining 7 free slots on the platform will likely be utilised through further expansion of infill drilling at Tchendo due to the significant subsurface potential, particularly in the Senonian interval which has an estimated in-place oil volume as high as 700 MMbbls but to date a very modest recovery factor of just 3%. Therefore, to date, the Senonian interval at the Tchendo field constitutes the largest untapped potential for infill drilling within PNGF Sud.

Tchibeli Field

Tchibeli is an oil field producing from two reservoir levels within the Albian aged (Cretaceous) Sendji Formation. The upper reservoir is a mix of carbonates and clastics, while the lower interval is a purely carbonate reservoir. The reservoir depth is 2,000 mTVDSS and the water depth is 100 m. The dome shaped structure known as a four-way turtle-back closure is segmented by several cross-cutting faults.

Reservoir quality is fair to good. The field was discovered in 1986 and started production in 2000. Peak production was reached shortly after start-up with three oil producing wells. Reservoir pressure is maintained by water injection. Production is artificially lifted through the utilisation of electrical submersible pumps.

A new export pipeline was installed from the Tchibeli field to the Tchibouela field in 2019 with oil from Tchibeli now able to go directly to the Tchibouela processing facility.

A four well infill drilling program, consisting of two producers and two injectors, is planned within the Tchibeli field with an expected drilling start in 2022.

Tchibeli North-East is a smaller, undeveloped Albian aged discovery north-east of the Tchibeli which is assumed to be developed in the near future, the resources are currently included in the company 2C estimates.

Litanzi Field

The Litanzi field produces oil from an Albian aged Sendji Formation carbonate reservoir interval. The structure which is located north-east of the Tchibeli field consists of a relatively thin reservoir interval cut by numerous faults that dip towards the west. The reservoir depth is at 1,600 mTVDSS and the water depth is 100 m. The Litanzi field was discovered in 1990 and started production from one oil producing well drilled from the Tchendo platform in 2006. Current production comes from a single oil well which is supported by one water injector well; production has increased slightly since 2016.

A four well infill drilling program, consisting of two producers and two injectors, is planned within the Litanzi field with an expected drilling start in the near future.

PNGF Bis

To date, three exploration wells have been drilled on the PNGF Bis licence area. The LUSM-1 exploration well drilled on the Loussima prospect in 1985 discovered oil in the early Cretaceous aged pre-salt Vandji formation. Loussima SW was discovered by the LUSOM-1 exploration well in 1987, again encountering oil in the Vandji formation. A second well, SUEM-2, was drilled on Loussima SW in 1991 to appraise the discovery. Hydrocarbon shows were also encountered in one of the wells within the Albian post-salt Sendji formation, (analogue to Tchibeli and Litanzi field reservoirs in PNGF Sud), however with no production testing. The depth to the Vandji reservoir is 3,250 mTVDSS, to Sendji around 1,940 mTVDSS and the water depth in the area is 110 m. Tests on the Loussima SW LUSOM-1 well produced 4,700 Bopd and the SUEM-2 well yielded 1,150 Bopd.

The Group has not secured the rights to carry out petroleum activities on PNGF Bis and any exploration, development and production is subject to the Group entering into a production sharing contract with the relevant governmental bodies. Subject to securing the rights to carry out such petroleum activities on PNGF Bis, the Group wished to explore the possibilities of starting with a long-term production test from an existing wellhead platform which will be tied back to the Tchendo field via pipeline and develop PNGF Bis into a permanent producing asset.

Production history

Initially discovered in 1979, PNGF Sud commenced production in 1987. In 2020 average gross production was 22,713 Bopd from five oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi. Following the establishment of the new licence group to the PNGF Sud licence in 2017, significant operational improvements have been made, increasing gross production from approx. 15,000 Bopd in January 2017 to 22,713 Bopd in 2020, while reducing operating costs from approx. 26 USD/bbl in 2016 to an average level of 10.4 USD/bbl in 2020. The production increase has mainly been driven by optimising performance of existing wells. Through well optimisation, surface infrastructure and process improvements coupled with infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

Facilities

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from about 60 active production wells, with oil exported via the onshore Djeno terminal. With its long production history, substantial well count and extensive infrastructure, PNGF Sud represents a well-diversified and low risk production asset with material reserves and a low break-even cost.

Reserves and resources

In March 2021 AGR performed a full Competent Persons Report (CPR) covering the Reserves (1P, 2P and 3P) and Resources (1C, 2C and 3C) in both PNGF Sud and PNGF Bis. The figures presented below were evaluated as of 31 December 2020.

Gross production in 2020 was 8.31 MMbbls of oil and 1.0 Bcf of gas. This corresponds to average gross production rate of 22,713 Bopd and 2.7 MMscfd in 2020 Up to end of October 2021, the gross oil production has averaged 20,304 bopd (based on daily reports) with a forecasted average production for 2021 of 20,500 bopd.

As per the reserves guidelines referred to in Section 8.2.1, the gas reserves accounted for in the CPR are limited to gas used for power generation purposes (on Tchibouela only). This gas is used as fuel for power generating turbines located centrally in the field with export of power to individual field platforms via electrical power cables. For the purpose of this report, the numbers quoted below as MMbbls do not include the oil equivalent gas.

As of 31 December 2020, AGR evaluated the five PNGF Sud fields at (i) gross 1P (Proved Reserves) of 86.20 MMbbls, (ii) gross 2P (Proved plus Probable Reserves) of 120.20 MMbbls, (ii) gross 3P (Proved plus Probable plus Possible Reserves) of 152.40 MMbbls, (iv) gross 1C Resources of 26.0 MMbbls, (v) gross 2C Resources of 43.40 MMbbls and (vi) gross 3C Resources of 74.60 MMbbls.

These reserves figures allocated at the Group's level (based on pro rata indirect ownership) amount to (i) 1P (Proved Reserves) of 14.51 MMbbls, (ii) 2P (Proved plus Probable Reserves) of 20.23 MMbbls, (iii) 3P (Proved plus Probable plus Possible Reserves) of 25.65 MMbbls, (iv) gross 1C Resources of 4.38 MMbbls, (v) gross 2C Resources of 7.30 MMbbls and (vi) gross 3C Resources of 12.56 MMbbls.

These Reserves and Contingent Resources are the net reserve volumes of the Group.

	Gross Reserves (developed or under development) as per 31.12.2020								
	1P			**2P**			3P		
	Oil MMbbls	Gas bcf	Boe MMboe	**Oil MMbbls**	**Gas bcf**	**Boe MMboe**	Oil MMbbls	Gas bcf	Boe MMboe
100% PNGF Sud									
Tchibouela	50.80	11.90	52.90	**62.80**	**16.90**	**65.80**	76.40	25.40	80.90
Tchendo	21.10	-	21.10	**28.90**	**-**	**28.90**	36.00	-	36.00
Tchibeli	7.40	-	7.40	**17.70**	**-**	**17.70**	26.50	-	26.50
Litanzi	6.90	-	6.90	**10.80**	**-**	**10.80**	13.50	-	13.50
Subtotal	86.20	11.90	88.30	**120.20**	**16.90**	**123.20**	152.40	25.40	156.90
100% PNGF Bis									
Loussima (Bis)	-	-	-	**-**	**-**	**-**	-	-	-
Total	86.20	11.90	88.30	**120.20**	**16.90**	**123.20**	152.40	25.40	156.90

	Gross Contingent Resources (undeveloped) as per 31.12.2020								
	1C			**2C**			3C		
	Oil MMbbls	Gas bcf	Boe MMboe	**Oil MMbbls**	**Gas bcf**	**Boe MMboe**	Oil MMbbls	Gas bcf	Boe MMboe
100% PNGF Sud									
Tchibouela	14.70	8.90	16.30	**23.10**	**13.80**	**25.50**	37.40	22.30	41.30
Tchendo	5.40	-	5.40	**9.10**	**-**	**9.10**	19.20	-	19.20
Tchibeli	5.90	-	5.90	**11.20**	**-**	**11.20**	18.00	-	18.00
Litanzi	-	-	-	**-**	**-**	**-**	-	-	-
Total	26.00	8.90	27.60	**43.40**	**13.80**	**45.80**	74.60	22.30	78.50
100% PNGF Bis									
Loussima (Bis)	22.40	-	22.40	**28.90**	**-**	**28.90**	35.80	-	35.80
Total	48.40	8.90	50.00	**72.30**	**13.80**	**74.70**	110.40	22.30	114.30

	Net PetroNor reserves (developed or under development) as per 31.12.2020								
	1P			**2P**			3P		
	Oil MMbbls	Gas bcf	Boe MMboe	**Oil MMbbls**	**Gas bcf**	**Boe MMboe**	Oil MMbbls	Gas bcf	Boe MMboe
16.83% PNGF Sud									
Tchibouela	8.55	2.00	8.90	**10.57**	**2.84**	**11.07**	12.86	4.27	13.62
Tchendo	3.55	-	3.55	**4.86**	**-**	**4.86**	6.06	-	6.06
Tchibeli	1.25	-	1.25	**2.98**	**-**	**2.98**	4.46	-	4.46
Litanzi	1.16	-	1.16	**1.82**	**-**	**1.82**	2.27	-	2.27
Subtotal	14.51	2.00	14.86	**20.23**	**2.84**	**20.73**	25.65	4.27	26.41
23.56% PNGF Bis									
Loussima (Bis)	-	-	-	**-**	**-**	**-**	-	-	-
Total	14.51	2.00	14.86	**20.23**	**2.84**	**20.73**	25.65	4.27	26.41

	Net PetroNor Contingent Resources (undeveloped) as per 31.12.2020								
	1C			**2C**			3C		
	Oil MMbbls	Gas bcf	Boe MMboe	**Oil MMbbls**	**Gas bcf**	**Boe MMboe**	Oil MMbbls	Gas bcf	Boe MMboe
16.83% PNGF Sud									
Tchibouela	2.47	1.50	2.74	**3.89**	**2.32**	**4.29**	6.29	3.75	6.96
Tchendo	0.91	-	0.91	**1.53**	**-**	**1.53**	3.23	-	3.23
Tchibeli	0.99	-	0.99	**1.88**	**-**	**1.88**	3.03	-	3.03
Litanzi	-	-	-	**-**	**-**	**-**	-	-	-
Total	4.38	1.50	4.65	**7.30**	**2.32**	**7.71**	12.56	3.75	13.21
23.56% PNGF Bis									
Loussima (Bis)	5.29	-	5.29	**6.82**	**-**	**6.82**	8.45	-	8.45
Total	9.66	1.50	9.93	**14.12**	**2.32**	**14.53**	21.00	3.75	21.66

8.2.3. Guinea-Bissau – Sinapa (Block 2) and Esperança (Block 4A and 5A) licences

Details of the transaction

On 20 November 2020, the Company announced the purchase of SPE Guinea Bissau AB[17] from Svenska Petroleum Exploration AB (the "Guinea-Bissau Transaction"). The transaction received the required in-country regulatory approvals, published in the Official Gazette of Guinea-Bissau (in Portuguese, Boletim Oficial) in late April 2021.

Subsequently, PetroNor E&P AB has assumed the operatorship of the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau. The current exploration phase on both licences has recently been extended for 3 years and both are valid until 2 October 2023.

Geological description

The Sinapa and Esperança licences cover a combined area of 5,725 km^2 offshore Guinea-Bissau in water depths ranging from 20m to 600m. The blocks are located in the geological province called the Guinea Plateau covering the offshore shelf of Guinea-Bissau and Guinea-Conakry.

Continental breakup via tectonic rifting along the Central Atlantic margin, initiated in the late Triassic to early Jurassic, created a number of isolated basins into which sediments were deposited. After initial breakup and active rifting, a passive margin setting prevailed with the development of carbonate platform facies along the continental shelf from the Mid Jurassic. Clastic sediments sourced from the onshore Bove Basin to the east and transported via the Rio Corubal drainage system were deposited across this part of the margin during the Albian forming a set of progradational deltaic sequences. The Cenomanian-Turonian marine transgression led to flooding of the margin and deposition of marine source rocks across the

[17] As of 4 June 2021, SPE Guinea Bissau formally changed its name to PetroNor E&P AB.

shelf and within the deep Cretaceous Central Atlantic basin to the west. On the shelf, these source rocks are currently within the oil generation window and have charged Albian reservoirs within the Sinapa discovery in Block 2 (light oil).

Mobilisation of the Jurassic Salt created a number of salt related traps within the Sinapa and Esperança licences which were the focus of early exploration efforts. More recently, attention has shifted to the shelf margin play with the easterly counter dip of the deeply eroded shelf margin setting up large traps analogous with the Sangomar field offshore Senegal to the north.

Exploration potential

The Sinapa and Esperança blocks contain two Cretaceous aged shelf edge prospects, Atum and Anchova, which are directly analogous to the on trend Woodside operated Sangomar field development in Senegal. The prospects were mapped on 3D seismic acquired by Polarcus in 2016 which was reprocessed and integrated into the TGS JAAN regional multi-client 3D.

The Atum prospect in Block 2 is a large 3-way closure below the Senonian unconformity which defines the western margin of the prospect. Two potential reservoir targets have been identified within the Albian, the Upper Albian S1 and an intra Albian S2 clinoform package. The Albian reservoirs directly overly a set of high amplitude, potentially Aptian aged clinoforms interpreted to be part of the Early Cretaceous prograding carbonate platform margin and could represent a deeper drilling target.

Oil migration from the proven oil mature Cenomanian-Turonian aged source rocks on the shelf to the north-east and Turonain source rocks thought to be within the oil window to the west of the Cretaceous aged shelf margin are expected to charge the Albian reservoirs at the Atum and Anchova prospects. The top and lateral seals to the shelf margin prospects are provided by intra Albian and Cenomanian shales and Palaeocene marine shales that onlap the Senonian unconformity.

The Anchova prospect is the southerly continuation of the Atum prospect and straddles the boundary between Blocks 2 and 4A. Similarly to Atum, Anchova is a 3-way closure below the Senonian unconformity and is separated from the Atum structure by a saddle defined by a large canyon. Salt diapirism has modified the western and eastern flanks of the Anchova structure with up dip thinning and termination of the S1 and S2 reservoirs against the flanks of the salt.

An upside case of the combined Atum and Anchova prospects filled below the saddle point separating the independent closures, which ultimately spills to the north of Atum, has also been considered. Potential resource calculations for the combined case have been calculated and are presented below.

Svenska Petroleum Exploration AB was in the advanced stages of planning for the drilling of the Atum-1X well to test the Atum prospect prior to delays in gaining partner approvals due to the disputed presidential elections in late 2019 early 2020. Long lead items required for drilling operations have been secured and a number of pre-drill studies completed. Well planning can be recommenced at short notice.

Resources

Unrisked probabilistic potential recoverable resource calculations made by Svenska Petroleum Exploration AB for the independent Atum and Anchova closures at Albian S1 and S2 levels as well as the combined Atum / Anchova case, all figures in million barrels of oil equivalent:

Independent closures:

REC	**P90**	**P50**	**PMean**	**P10**
Atum S1	20	32	33	47
Anchova S1	10	24	33	68
Atum S2	55	180	200	370
Anchova S2	37	107	128	245

Combined Case:

Rec	**P90**	**P50**	**PMean**	**P10**
S1	32	152	233	552
S2	25	167	265	625

The reserves figures have not been audited by the Group or by any independent third party.

8.2.4. The Gambia – A4 licence

Overview and background

The Group (at the time African Petroleum Corporation) acquired a 60% interest in the A1 and A4 licenses offshore The Gambia in August 2010 from Buried Hill and became 100% owner and operator in July 2014. The Group entered into arbitration proceedings with The Gambia following the lodging of Requests for Arbitration ("**RFA**") documents with the International Centre for Settlement of Investment Disputes ("**ICSID**") in October 2017 to protect its interests in the A1 and A4 licences.

As announced on 19 September 2020, PetroNor E&P Gambia Ltd was awarded the rights to a new 30-year lease for the A4 licence. The award was part of a settlement agreement with the Government of The Gambia connected to the arbitration of the A1 and A4 licences previously issued in 2006. The company was given an initial one-year evaluation period without any minimum work program or spend commitments in order to find a partner for the licence. On 19 October 2021, PetroNor received confirmation from the Government of The Gambia that a further one-year extension to the initial evaluation period for the A4 licence, until 18 October 2022 had been granted. This will enable the Company to progress with its ongoing discussions with potential partners.

The terms of the new license are based on the newly developed Petroleum, Exploration and Production Licence Agreement (PEPLA). PetroNor E&P Gambia Ltd will be able to carry approved prior sunk costs associated with A4 into the new agreement.

The PEPLA is a royalty plus tax system valid for 30 years with an option of a 10-year extension. The initial six years exploration period is divided into three periods of two years during which exploration activities are to be completed. Post discovery, the licence moves into an exploration / appraisal phase where the commercial potential of the discovery is ascertained and a development decision taken, following which the licence moves into a development and subsequent production phase.

Geological description

The A4 licence is located offshore within the Mauritania-Senegal-Gambia-Bissau-Conakry Basin. The Basin was formed during the initial Triassic to Jurassic rifting of the Central Atlantic region. Hydrocarbons are proven throughout the basin, including current producing fields in Mauritania, major accumulations at Dome Flore ("**AGC**")[18] and most notably the Sangomar field in Senegal, 30 km to the North of the A4 licence. First oil is expected at Sangomar in 2023 with a plateau production rate of 100,000 Bopd forecasted by the operator, Woodside.

Several wells have been drilled and proven to be successful in the area. Good quality oil has helped to demonstrate that there is abundant charge potential from multiple source rocks within the area (described as 'outstanding' by FAR Ltd). Good quality oil (32 API) at shallow depth below sea floor in the Sangomar field has proven that oil charge is recent and that source rocks are generating significant volumes of oil present day. These multiple source rocks of Neocomian and Aptian to Turonian age are proven in wells drilled on the continental shelf, the deep water Fan-1 well (28 to 42 API) as well as the DSDP-367 well, some 400 km offshore, as well as in wells along the margin to the south. High quality, well connected Albian marine sandstones form the main reservoir target, but good quality reservoir is present in the Cenomanian as well as some younger units. There may also be potential for good reservoir development within the Aptian aged interval along the margin.

Further exploration is anticipated by FAR and Petronas in Block A2 in late 2021. The A1 block was relinquished by BP in July 2021 (a Corporate decision not based on the licence potential) but this highly attractive block is expected to be included in a Gambia mini bid round in the near future. Further likely success in the vicinity of the A4 licence is expected to further de-risk the Group's acreage in Senegal and The Gambia.

Shelf-edge clastic Prospects in licence A4

The Lamia prospect is a major three-way closure with stacked Albian clastic reservoirs, analogous to the Sangomar field. The eastward tilt of the underlying carbonate platform creates a trapping geometry at the Cretaceous shelf edge. High quality Albian sandstones (25% porosity in Sangomar field) are deposited up to the shelf edge and into the basin to the west (the 'Fan Plays'). Hydrocarbons generated from multiple prolific, proven source rocks migrated eastwards from the basin down-

[18] Agence de Gestion et de Cooperation entre Le Senegal at La Guinee Bissau - Joint Development Zone between Senegal and Guinea-Bissau

dip to the west, up into reservoirs on the shelf margin. Older source rocks (Albian / Aptian) play an important role to the south of block A4. Cenomanian aged source rocks are modelled to be in the early oil window in the basinal area of A4 also.

Careful amplitude extractions from 3D seismic data have built a compelling case for reservoir development across the licence. The Lamia prospect also has a potentially significant Aptian clastic target beneath the primary Albian reservoirs, the model is supported by the Wolof-1 well to the South-East. The Lamia prospect exhibits an areal extent similar to the Sangomar field.

Additional 'Shelf' leads are being matured on PSDM data. The areal extent of potential prospects is very dependent on getting the depth conversion of the seismic data correct hence the significant efforts invested. The TGS multi-client JAAN 3D pre-stack depth migration is being utilised for these purposes of accurate prospect definition and this work will be used as input for a new CPR. (Competent Persons Report). Access to additional well information to the east will be useful for updating the A4 portfolio if available.

Fan Prospects

The Acacia and Rosewood prospects are Santonian to Cenomanian/Albian in age. These prospects have good seismic amplitude support for reservoir development and amplitude maps clearly show reservoir deposition in the trap position for all prospects. Vertically stacked targets from the Albian to the Cenomanian and Senonian, enables one well to test multiple prospective levels. The Albian age targets in Rosewood / Acacia Deep are the primary target, these appear to extend northwards into the A1 block. The basinal prospects are anticipated to have significantly improved reservoir porosity and permeability in A4 due to the shallower burial depth of the Albian to the south (approximately 1,000 m less burial), in comparison to the Fan-1 well in the Sangomar licence which reported poor to moderate reservoir quality. Cenomanian/Albian/Aptian source rocks are interbedded with the main reservoir units for efficient charge. The basinal prospects are viewed as high potential in A4 despite a slow appraisal follow-up to the Fan-1 discovery in the Sangomar licence to the north.

Resources

The sum of the mean case net unrisked prospective oil resources for prospects within the licence are estimated to be approximately 2 billion barrels of oil. This estimate is based on the expectations of the management of the Company and has not been audited by any independent third party.

8.2.5. Senegal – Rufisque Offshore Profond and Senegal Offshore Sud Profond

Overview and background

Although currently in arbitration, the Company reserves its rights in the exploration blocks ROP and SOSP (together the "Senegal Licences") in Senegal through its 90% owned subsidiary African Petroleum Senegal Ltd. The Senegal Licences are located offshore Southern and Central Senegal, covering a combined surface area of 15,796 km^2, with the remaining 10% carried interest in the licences held by Petrosen, the national oil company of Senegal. The Group is therefore committed to cover 10% of the costs in the licence (exceeding its interest).

The current phase of the ROP PSC ended in October 2015; however, the Company lodged a request for an extension with the Government of Senegal. Under the terms of the ROP PSC the block remains active unless and until a termination procedure is enacted by the Republic of Senegal. To date, the Republic of Senegal has not validly enacted such termination procedure, and accordingly the Company reserves its rights under the ROP PSC.

A new production sharing contract covering the same area as the ROP PSC was awarded to Total in 2017 and subsequently farmed down to Petronas in August 2018. Irrespective of this, the Company reserves its right under its ROP PSC.

The Company elected to move into the next phase of the SOSP PSC in late 2017 and requested that the outstanding drilling commitment in the expiring phase be transferred to the next phase as a seismic commitment. To date, the Republic of Senegal has not responded to this request and accordingly the Company reserves its rights under the SOSP PSC.

In January 2018, the Group's wholly owned subsidiary, African Petroleum Senegal Limited, lodged RFA documents with ICSID in order to protect its interests in the ROP and SOSP PSCs in Senegal. As announced on 5 May 2020, the Company reached a mutual agreement with the Government of Senegal to suspend the arbitration related to the Senegal Licences for a period of six months with a view to reaching a satisfactory outcome for all parties, and a formal request has been lodged with ICSID to suspend the process.

Subsequently, the parties further extended the suspension by an additional three months as announced on 30 October 2020, and with further two months as announced on 2 February 2021. On 5 April 2021, the Company announced that throughout the prolonged suspension period, the Company has made significant efforts to reach a mutually beneficial solution and has held numerous progressive meetings with the relevant authorities to no avail.

The Company has now re-engaged in the arbitration process and has prepared and submitted an Expert Witness rebuttal to the Senegalese Government Expert Witness report for ROP and SOSP. The final hearing is scheduled for the end of Q1 2022.

Geological description

The Senegal Licences are also located offshore within the Mauritania-Senegal-Gambia-Bissau-Conakry Basin which extends from Mauritania to Guinea.

The primary focus in SOSP has been the 'fan play' where two major fan systems, Kapok and Jaloo, have been mapped by the Company and reviewed by ERC Equipoise. These fans are large in area and have multiple stacked reservoir targets and significant mean un-risked resources in place. On the shelf to the east, clastic / carbonate 'Leads' have been identified that will be matured to Prospect status with further seismic mapping. This has now been made possible by the TGS acquisition of new 3D seismic survey over the area as part of the JAAN 3D multi-client merged dataset. In addition, maturation of Sangomar field lookalike prospects on the platform, will enhance the exploration portfolio. Significant potential has also been identified in carbonate targets (karst, slope wedge and fore-reef debris) though final prospect maturation is still required and dependent on an accurate depth conversion/migration. It is anticipated that CNOOC / Impact will possibly drill an important well to the South of SOSP in the AGC area in 2022.

The ROP licence was awarded to Total in 2017 (this is disputed and arbitration is ongoing) and in August 2019, Total plugged and abandoned the Jamm-1x well in 2,400m water depth, as a 'non-commercial' oil discovery according to Upstream newspaper (along with partner, Petronas). Total had acquired a large 3D seismic survey prior to this over the ROP licence to enable evaluation of the deeper water area of the licence. The primary focus of the prospectivity prior to this was the south-east area of the block utilising reprocessed existing 3D seismic, with a focus on extending the Sangomar field success northwards.

The main prospects in the 2015 ERCE CPR are 'fan plays' with Santonian to Aptian age Middle-Upper Cretaceous reservoir targets in the eastern part of the ROP licence.

ROP Baobab prospect

Targets evaluated by ERC Equipoise range from Albian in age in the deep section to Maastrichtian in age in the shallow. A porosity vs depth below mud line (BML) relationship has been used to guide input porosity ranges for use in potential resource calculations. These targets are predominantly deep water sands deposited in channels and lobes forming an apron at the break of slope along the basin margin. Amplitude extractions have been used to map the extent of the target sandstone reservoirs, unfortunately though, seismic data quality at the eastern edge of the 3D seismic is poor and there are some significant imaging issues due to a complex overburden. However, several stacked targets can be tested with a single well bore.

The primary Albian aged target at 'Baobab' is buried more than 3000m below sea-bed and subsequent to the report of low net-gross poor quality reservoir in the FAN-1 discovery well, 18 km to the South, The geological risk attached to this primary Albian target was increased due to expected low porosity. The focus has switched to evaluating younger targets but seismic coverage does not extend far enough to the east to fully evaluate the trap. Additional data acquisition was proposed previously, for future evaluation improved data quality and coverage will be required to further mature the main Turonian-Santonian-Campanian targets. Further appraisal of the Fan-1 discovery may however impact the strategy in ROP. If the Fan-1 discovery is appraised and proves 'commercial flow rates' within the Albian interval, then the Baobab Albian prospect in ROP - an extension of Fan-1 discovery will be further de-risked and may prove a more attractive target. However, at present the reservoir risk attached to Baobab Albian level is such that the Group would not position a well to target the Albian as a primary target.

SOSP Kapok and Jaloo prospects

Kapok and Jaloo are very significant fan systems of Aptian-age (deep) to Cenomanian-age (shallow). Pinch-out of the fans is very well defined up-dip to the east in deeply cut canyons on the Cretaceous carbonate platform. Amplitude extractions indicate good reservoir development, though a recent submarine canyon in the overburden causes a wipe-out of these amplitudes at depth and apparent separation of the fan systems. However, they are likely connected at the Albian level and volumes quoted have assumed this. At other levels, the fan systems have been assumed as separate discrete bodies. Viewed along strike, approximately north-south, seismic data indicates that reservoir development could be significant. Major prograding shallow marine delta systems are mapped on 2D data to the east of SOSP, providing an excellent supply of clastic reservoir to the deepwater SOSP block. Further de-risking based on amplitude versus offset comparisons may be possible with the TGS multi-client 3D seismic images. In addition, there is a very thick sequence of Cenomanian age reservoir that has clearly been reworked by contourite currents which may improve reservoir quality further. These prospects lie in approximately 3,000 m water depth.

Potentially the most interesting prospectivity in the view of the Company, analogous to the Sangomar field to the north, is the Cassia lead on the Shelf or carbonate platform area on the east side of the block in shallower water depth (1,850 m). This was previously only covered by 2D and 3D seismic; new coverage from the TGS multi-client 3D survey (JAAN) will enable maturation to prospect status. The Pre-stack depth migration now available will hopefully imaging the right trapping configuration and elevate Cassia in priority.

Reserves and resources

The sum of the mean case net unrisked prospective oil resources within the ROP and SOSP licences is estimated to be approximately 1.8 billion barrels of oil. This prospective resource estimate is based on the ERC Equipoise 2015 CPR completed for APCL covering both ROP and SOSP licences.

8.2.6. Nigeria – OML-113

The Aje Transaction

As announced on 21 October 2019, the Company entered into an agreement with Panoro Energy ASA ("**Panoro**") (the "**Panoro Agreement**") for the acquisition of certain companies holding interests in Offshore Mining Lease no. 113 ("**OML-113**") offshore Nigeria, containing the Aje oil and gas field ("**Aje Field**") ("**Aje Transaction**"). The Panoro Agreement contemplates the acquisition of 100% of the shares of Panoro's fully owned subsidiaries Pan-Petroleum Services Holdings BV ("**PPSH**") and Pan-Petroleum Nigeria Holdings BV ("**PPNH**"), which currently hold 100% of the shares in Pan-Petroleum Aje Limited, which participates in the exploration for and production of hydrocarbons in OML-113.

The consideration payable by the Group under the Panoro Agreement is (i) issue of shares in the Company for USD 10 million and (ii) a contingent payment obligation after PetroNor has recovered all costs related to the accumulated investments incurred after the Completion Date equal to USD 0.10 per 1,000 Cubic Feet of Aje Gas sales volume limited to USD 16.67 million.

In parallel, the Company concluded a separate investment and shareholders’ agreement with the OML-113 operator YFP ("**YFP Agreement**") to create a new holding company Aje Production AS (the "**SPV**") that will see the SPV assume the lead technical and management role in the next phases of the Aje Field development. PetroNor and YFP will hold respectively 45% and 55% of the SPV shares, and the ability to appoint up to two directors each. The SPV will require two directors jointly to sign on its behalf, of which one is appointed by PetroNor and one appointed by YFP. The SPV will include the current license ownerships of YFP (the operator), YFP-DW and Panoro.

Together these agreements provide the framework and pathway towards sanctioning of the next phases of the Aje Field development in order to unlock its significant value through accessing the substantial proven gas and liquid in place reserves.

The completion of the Aje Transaction was subject to the satisfaction of certain conditions precedents, including the regulatory approval of the Nigerian Department of Petroleum Resources and consent of the Minister of Petroleum Resources.

The regulatory approval process in Nigeria, though delayed by the impact of the COVID-19 pandemic, is now finalized subject to the payment of USD 1 million to the Nigerian Government for the premium on assignment for OML-113 before 30 April 2022. The Aje Transaction is expected to be completed before 30 April 2022.

Upon the successful completion of the Aje Transaction, the Group will in the OML-113 licence acquire a nominal participating interest on 34 % and a revenue interest on 24.3%. These figures are based on the Group holding a 45% equity interest in the SPV, which in turn holds nominal licence interest on 75.5 % and a revenue licence interests on 54.1%. The table below shows all CAPEX, OPEX, and revenue for the SPV. PetroNor's interest is 45% relating to each figure.

The proportional allocation of operating expenditures and capital expenditures deviate from pro-rata allocation of revenues. Allocation of operating expenditures and capital expenditures are based on the following mechanic which were established in the Farm-In Agreements and Joint Operating Agreements in 2007.

SPV Aje Production	**Period 1:** Prior to YFP Payout		**Period 2:** Post YFP Payout		**Period 3:** Post Project Payout		
Participation Interest	CAPEX and OPEX	Revenue (cost recovery and profit sharing)	CAPEX and OPEX	Revenue (cost recovery and profit sharing)	CAPEX	OPEX	Revenue (cost recovery and profit sharing)
75.50%	38.755%	54.066%	38.755%	38.755%	38.755%	54.066%	54.066%

As of the date of this Prospectus, the licence is in "Period 1" and the commencement of "Period 2" is subject to YFP receiving USD 30 million in net proceeds. This is the cost incurred by YFP in OML-113 prior to the first farming agreement in 2007. YFP has received USD 12 million and the recovery of an additional USD 18 million is required for commencement of "Period 2". Based on the expectations of the management of the Company, this is expected to be incur in about 2 years. The commencement of "Period 3" is subject to the net proceeds less the prior costs exceeding the cumulative expenditure. Based on the expectations of the management of the Company, this is expected to take place in about 3 to 4 years.

Geological description

The OML-113 Aje Field is a four-way-closure, located in offshore Western Nigeria on the shelf slope of the Dahomey Embayment in the East of the Benin Basin, adjacent to the Benin border. The field is located on the shelf slope with water depths of about 150 m in the shallow and more than 1,000 m in the deep section. Major transform faults run through the area trending south-west to north-east, one of which defines the Eastern limit of the Aje Field.

Significant volumes of gas and oil have been discovered at several reservoir levels within the Aje Field. The producing reservoirs within the field are Turonian and Cenomanian in age, and were deposited as upper and lower shoreface sands cross cut by sand filled tidal channels. All reservoir intervals within the field have high porosity and permeability values.

The primary reservoir of Turonian age has a maximum vertical hydrocarbon column consisting of 100 m of wet gas above a lower oil leg of 10 m. The Aje-5ST2 well has produced approximately 1.5 MMbbls of oil from the Turonian oil leg. The approx. 500 Bscf of recoverable gas reserves have not been produced to date.

The secondary reservoir is split into an Upper and Lower Cenomanian aged oil filled intervals. The Aje-4 well produces from a 22 m oil column in Upper Cenomanian and 18 m oil column in Lower Cenomanian.

Additional proven reservoirs in the Aje Field are Albian fluvial to shallow marine tight sands with proven gas condensate and the syn-rift sands proven to be hydrocarbon filled in the nearby Ogo field.

A number of prospects have been identified surrounding the Aje Field mainly in the Cenomanian and Turonian interval, but there is also potential in the deeper reservoirs.

Production history

The Aje Field has been producing since 4 May 2016. Production started through the Aje-4 and Aje-5 wells producing oil from Cenomanian reservoirs. The Aje-5 well watered out after a few months, hence Aje-5ST2 was drilled and has been producing from the Turonian oil zone since May 2017. The average operational uptime for the field over the past 5 years is 95%.

As of 31 December 2020, the cumulative production from the Aje Field was 4.6 MMbbl, averaging 1,981 Bopd with a water cut of 60-70%.

Development

The Aje redevelopment project will target a Turonian gas development and Cenomanian oil. During phase 1, the plan is to change the FPSO, drill three development wells and build a gas pipeline to shore. During phase 2, the field gas handling capacity will be expanded from 70 MMscf/d to 110 MMscf/d. Furthermore, a tentative installation of gas-to-power and an LPG plant will be implemented.

Facilities

The Aje Field is currently produced and processed via the FPSO Front Puffin chartered by the Aje JV partnership.

Front Puffin is a single-sided FPSO vessel with a hydrocarbon production facility designed to receive well fluids, separate and stabilize the produced crude and store the stabilized crude in the FPSO's cargo tanks, treat and discharge the produced water and compress the produced gas for gas lift, with the balance of the gas being flared.

Reserves and resources (subject to completion of the transactions)

Gross 2P reserves for Aje are 1.6 MMbbls and 2C resources are 107.4 MMboe (gas and condensate) as per 31 December 2020.

	Gross Reserves (developed or under development)			**Gross Contingent Resources (undeveloped)**			
	1P MMboe	2P MMboe	3P MMboe	**1C Oil MMbbls**	**2C Oil MMbbls**	**2C Gas bcf**	**2C Boe mmboe**
OML-113							
Aje	-	1.57	-	**-**	**27.60**	**448.00**	**107.4**
Total	-	1.57	-	**-**	**27.60**	**448.00**	**107.4**

This reserves estimate is based on the expectations of the management of the Company and has not been audited by any independent third party. The Aje Transaction is expected to be completed by 30 April 2022.

8.3. Legal framework for petroleum business

8.3.1. Regulatory and environmental framework for the Republic of Congo

In the Republic of Congo, PetroNor holds its indirect interest in PNGF Sud (comprised of three liquid and gaseous hydrocarbons production licenses: Tchendo II, Tchibouela II, and Tchibeli-Litanzi II) through its local subsidiary HEPCO. These three production licenses were formally awarded in 2017 to the Congolese National Oil Company ("**SNPC**"), and a separate PSC is in place in connection with each of them. Other than SNPC, the current members of the contractor groups under these PSCs are Perenco Congo (operator), HEPCO, Kontinent Congo, Africa Oil & Gas Corporation and Petro Congo.

As a company incorporated in the Republic of Congo, HEPCO is subject to the generally applicable regulatory requirements in force in the country.

The primary sources of law in Congo are the 2015 Constitution, the international treaties ratified by the country, the legislation passed by the Parliament, and the regulations enacted by the Government.

The Republic of Congo is a member State of the Economic and Monetary Community of Central African States, aiming to promote economic integration among countries that share a common currency, the CFA Franc, pegged to the Euro, at the rate of 1 Euro / 655.957 CFA Francs. CEMAC Regulations are directly and immediately applicable in all CEMAC member States. Currently, the CEMAC member States share a common financial and regulatory structure, and maintain a common external tariff on imports from non-CEMAC countries. The Republic of Congo has enacted its own General Tax Code in accordance with the applicable CEMAC Directives.

The Republic of Congo is also a member State of the Organization for the Harmonization of Business Law in Africa ("**OHADA**") which provides a harmonized business legal framework for its member States. Pursuant to the OHADA Treaty, Uniform Acts are directly applicable and binding in all member States.

In addition, the Republic of Congo is a party to the Treaty that created the Inter-African Conference on Insurance Markets ("**CIMA**"), which contains the CIMA Insurance Code. As per the CIMA Treaty, the CIMA member States are required to enforce the CIMA Insurance Code provisions regardless of any conflicting rules contained in their domestic legislation, whether prior or subsequent to the Treaty.

Owing to its status as an oil and gas company and as holder of participating interests in the PNGF Sud project, HEPCO is also subject to the applicable industry-specific laws and regulations, in particular the Hydrocarbons Code, enacted by Law 28-2016, of 12 October 2016.

The Hydrocarbons Code stipulates that no entity may engage in any upstream activity in the Republic of Congo without first being authorized by the State. Such an authorization takes the form of either a prospection authorization or a mineral title (i.e., an exploration license or a production license).

Exploration licenses and production are exclusively granted to SNPC, which is the exclusive concessionaire of petroleum mineral titles – in the form of exploration permits or production permits, granted by the Council of Ministers upon proposal of the Minister of Hydrocarbons – meaning that IOCs and private Congolese petroleum companies will have to associate themselves with SNPC to conduct petroleum operations. Production licenses grant to the contractor the exclusive right to perform hydrocarbons development and production works within the relevant production area. Production licenses are granted for a maximum period of 25 years in the case of liquid hydrocarbons, and 30 years in the case of natural gas or solid hydrocarbons (a once-only extension of up to 5 years may be applied for and granted). The development and production works must be carried out in accordance with an approved development and production plan which is to include, amongst other items, a geological and geophysical study of the deposit, a reservoir study, an economic study, a study on the exploitation of the substances associated to the liquid hydrocarbons, a detailed study on the facilities required for production, processing, transport and storage of hydrocarbons, a study on the contribution of the development and production project in terms of local content, and a timeline for the performance of the development and production works.

The rights and obligations of the contractor relating to a mineral title are defined in a petroleum contract, either in the form of a PSC or of a services agreement. These instruments define the conditions pursuant to which the contractor is to carry out the petroleum operations. Pursuant to a PSC, the State entrusts the contractor with the carrying-out of hydrocarbons exploration and / or production operations within a given area, with the contractor receiving a share of the production by way of recovery of costs and another share by way of compensation in kind. Throughout the duration of the petroleum contract, the contractor bears on an exclusive basis the technical and financial risks relating to the carrying-out of petroleum operations.

In its capacity as the entity to which exploration and / or production licenses are exclusively granted, SNPC will associate itself with third-party private entities, and together they hold participating interests in the petroleum contract corresponding to the license. The selection of the members of a contractor (other than SNPC) is made by the hydrocarbons administration pursuant to a tendering procedure (as happened in the case of the PNGF Sud project) or, in special cases, by direct negotiation.

The members of the contractor are jointly liable towards the State, to the extent of their respective participating interests, for the discharge of the contractor's obligations arising out from the petroleum contract. One or more members of the contractor group is appointed as operator, and it is entrusted with the carrying-out of the petroleum operations.

The State is entitled to a mandatory participation in upstream activities, ensured by means of SNPC holding a minimum non-assignable 15% participating interest in any petroleum contract, the financing obligations inherent to said minimum mandatory participation are entirely discharged by the other members of the contractor, pro rata to their respective participating interests, until such time as a production license is granted. Afterwards, the financing obligations inherent to the minimum mandatory participation in said production license are likewise carried by the other members of the contractor for the account of SNPC.

Under a PSC, (i) a portion of the net production is allocated to the payment of the production royalty, (ii) the contractor is entitled to a portion of the available net production by way of reimbursement of the recoverable petroleum costs, and (iii) the balance of the available net production is shared between the State and the contractor. The maximum percentage of that portion of the net production for a calendar year which may be allocated by way of cost oil is defined in the relevant PSC and is in principle limited to 50% (under certain conditions, it may be of up to 70%). The balance of petroleum costs not recovered in a calendar year will be carried forward to the subsequent years, until expiry of the relevant production license. Sharing of the profit oil between the State and the contractor will be made in accordance with the terms agreed in the PSC.

The contractor, and its subcontractors, service providers and suppliers are required to give preference to the hiring of Congolese personnel, and to prepare and implement programs for the recruitment, mentoring, training and development of its Congolese staff. In the production phase, these entities are also required to contribute to the programs for training and development of Congolese nationals, and to participate in the setting-up of permanent training and improvement facilities.

The contractor, and its subcontractors, service providers and suppliers must give preference to the goods supplied and services provided by Congolese companies, to the extent that their technical and commercial offers are substantially equivalent to those of foreign suppliers.

The development and production costs of Congolese origin must represent a minimum percentage (set on a case-by-case basis in the development and production plan, but which may not be lower than 25%) of the total development and production costs – with the costs corresponding to the difference not being recoverable, unless the contractor justifies the fact that said minimum percentage is not reached.

The Hydrocarbons Code stipulates that each company must take out insurance policies with insurance companies licensed in the Republic of Congo through insurance brokers organized under Congolese law.

The conditions for the supply of hydrocarbons to the domestic market are yet to be defined in developing regulations, but the Hydrocarbons Code expressly provides that it shall be exempt from duties and fees.

With respect to fiscal and parafiscal charges, the contractor and the members of the contractor are, in relation to the petroleum operations, exempt from any and all general duties and taxes, other than: the business license fee, the property tax and land tax, the commercial property occupancy tax, the single tax on salaries at the reduced rate and the labour union dues, withholdings of personal income tax, corporate income tax, investment income tax (dividends), and property rental tax payable by third parties, the contributions and fees in connection with the remuneration of services, corporate income tax, registration fees and stamp duties and the tax on the transfer of funds between Congo and abroad (and vice-versa).

Specifically, for the PSCs of PNGF Sud where HEPCO is a member of the contractor group, the contractor and the members of the contractor group are, in relation to the petroleum operations, exempt from all other taxes, duties, contributions, fees and levies of any kind, in force on the effective date of the Contract or which may be created subsequently.

In particular, the contractor shall be, among others, exempted from business license fees, tax on income securities for the amounts received and paid by the contractor, of all registration and stamp duties, property contributions built and non-built properties, value added tax and tax on the movement of funds.

Specifically in connection with petroleum operations, the contractor is subject to the following charges: signature bonus relating to the PSC, bonus for the granting of the production license further to an exploration license, bonus for the extension of the production licenses, and other bonuses (these bonuses do not qualify as a recoverable costs, but they are deductible from the taxable income relating to corporate income tax), surface fee and production royalty, provision for diversified investments, contributions for the training programs for Congolese personnel, for the verification and monitoring of the accounting records, and contribution for the environmental risks prevention fund, and the tax on the gains resulting from the assignment of participating interests in PSCs.

A royalty applies on the net production from each production license, at a rate of 15% for liquid hydrocarbons (under certain conditions, this rate may be reduced to a minimum of 12%) and 5% for natural gas and solid hydrocarbons.

The total or partial assignment by any member of the contractor of its rights and obligations under a PSC is subject to the payment of a flat fee corresponding to 10% of the resulting gain (the difference between the price paid to the assignor and the total amount of the costs yet to be recovered by the assignee). This fee does not apply in case the assignee is a company organized under Congolese law whose share capital is entirely held by the assignor.

No value added tax (or any similar tax on the turnover) applies to the contractor in relation to the activities in connection with the petroleum operations. In turn, the operations not qualifying as petroleum activities remain subject to the general tax regime.

The members of the contractor are individually subject to corporate income tax in connection with the petroleum operations, under the general conditions of the tax legislation, at a rate defined in accordance with the General Tax Code (currently set at 35%) and stated in the petroleum contract. Under PSCs, the corporate income tax is paid on a flat-rate and final-tax basis by delivering to the State its share of profit oil.

The Hydrocarbons Code also contains foreign exchange ("**FX**") provisions, which must however be interpreted in light of the FX regulations in force, including CEMAC Regulation 02/18/CEMAC/UMAC/CM, dated 21 December 2018, and the Instructions on its implementation since issued by the Central African States Bank ("**BEAC**"). Pursuant to the Hydrocarbons Code, the members of the contractor are afforded the following main rights and guarantees: (i) to receive abroad the funds obtained or borrowed, including the proceeds of the sales of their share of the production, and to freely dispose thereof; (ii) to transfer abroad the proceeds of the local sales of hydrocarbons, the proceeds of any type of the capitals invested, as well as the proceeds of the liquidation or realization of their assets in the Republic of Congo; (iii) to pay directly abroad the suppliers not domiciled in the Republic of Congo of goods and services required for the carrying-out of the petroleum operations in the country; and (iv) to freely convert local and foreign currency in connection with any FX operations relating to the petroleum operations in the Republic of Congo. In particular, the members of the contractor which are organized as Congolese companies for the purposes of holding participating interests in a petroleum contract (such as HEPCO) are entitled to hold accounts in foreign currency and assets abroad.

The abovementioned CEMAC Regulation (which, as noted above, is directly and immediately applicable in all CEMAC member States, including the Republic of Congo) and BEAC Instructions could impact the rights and guarantees afforded by the Hydrocarbons Code to the members of the contractor (including HEPCO), even if many of the requirements and restrictions of the new CEMAC Regulation are similar to those of the 2000 Regulation it expressly repealed. However, the fact that the new CEMAC Regulation gives the BEAC authority to impose sanctions suggest that such requirements and restrictions may be actively enforced from now on, at least to a certain extent. The most stringent / cumbersome of said requirements and restrictions are as follows: (i) legal persons qualifying as FX residents cannot open foreign currency bank accounts outside or inside the CEMAC, unless they obtain a prior authorization from the BEAC; (ii) FX residents must use their XAF local bank accounts to pay FX residents; (iii) export proceeds received abroad by FX residents must be repatriated within 150 days; (iv) transfers to non-CEMAC countries exceeding XAF 100 million must be notified 30 days in advance; (v) all imports must be declared, and those exceeding XAF 5 million must be domiciled with a CEMAC bank; (vi) funds borrowed abroad by FX residents must be repatriated or used for the purpose for which they were obtained; and (vii) investments of FX residents abroad are subject to the BEAC's prior authorization.

Under the regulatory requirements in the field of health, safety and the environment, the contractor, its subcontractors and its service providers are required to ensure, under the applicable international treaties and domestic laws and regulations: (i) the conservation of the natural resources, and the protection of health, safety and the environment, (ii) the use of techniques consistent with best international practice aimed at preventing the damage to health, safety or the environment within the exploration and production areas and the neighbouring areas, and (iii) the implementation of programs for pollution prevention, waste management, natural resources preservation, and restoration and reclamation of the damaged lands. In its capacity as member of the PNGF Sud contractor group(s), HEPCO is subject to these regulatory requirements.

These requirements include the preparation and submission to the Minister in charge of hydrocarbons of an environmental and social impact study, on whose approval the commencement of any in-field operations is dependent. The risks identified in the environmental and social impact studies must be the subject of budgeted plans for the management thereof, including (i) an emergency response plan in the case of a major incident, (ii) a waste management plan, (iii) a plan for the abandonment, dismantling and restoration of the sites, and (iv) an air discharges management plan.

Also, any incident in the carrying-out of the operations must be immediately notified by the contractor to the appropriate authorities, and after being overcome must be the subject of an incident management report. A national emergency response plan designed to ensure a swift and effective intervention in the event of a major hydrocarbons spill or of any other major incident is to be jointly implemented by the Ministers in charge of hydrocarbons, the environment, defence and territorial planning (in cooperation with other administrative authorities and the petroleum companies). This plan will provide for the setting-up of a national fund for the prevention of environmental risks, which is to be financed by an annual contribution from each contractor (corresponding to 0.05% of the net production). This is a recoverable cost which may be deducted from the taxable income.

The contractor is required to restore all sites at which operations were carried out, as well as the neighbouring areas, and shall bear all costs in connection therewith. This is to be made in accordance with an approved sites abandonment and restoration plan, addressing, amongst others, the following topics: (i) the technical and financial evaluation, as well as the abandonment works planning; (ii) the terms of the creation and funding of a provision allocated to the financing of the sites abandonment and restoration works; (iii) the procedures for the dismantling of all equipment and facilities installed by the contractor in connection with the petroleum operations; and (iv) the conditions for restoration of the sites in accordance with the best practices accepted in the international petroleum industry. The creation of the abovementioned provision for abandonment does neither relieve the contractor from its obligation to restore the sites nor does it limit said obligation.

The form of and conditions for submission and approval of the abovementioned plans, the terms of their implementation, the creation of the provision for abandonment, and the collection and management of the funds allocated to it are all matters yet to be further detailed and defined in developing regulations.

8.3.2. Regulatory and environmental framework for Guinea-Bissau

Prospecting, exploration, production and transportation of hydrocarbons in Guinea-Bissau is regulated by the Petroleum Law, Law No. 4/2014 passed by the National People's Assembly on 15 April 2014.

No person may prospect, explore or produce hydrocarbons without first procuring and being granted a licence or concession by the government and such licence or concession may only be awarded to the National Oil Company of Guinea-Bissau, Empresa Nacional de Pesquisa e Exploração Petroliferas E.C.P. ("**Petroguin**") in association with one or more companies.

Only companies that prove they possess the technical ability and financial capability required for the good performance of the licence work program may associate with Petroguin. This association must be in the form of a risk agreement, production sharing agreement, or any other contract of association that may be approved by subordinate legislation to Law No. 4/2014. Within such agreement Petroguin must have a participating interest in the production of any liquid or gaseous hydrocarbons discovered of no less than 10%.

The contractor group may not be awarded a licence or concession for more than two blocks and the same operator may not operate more than three blocks, regardless of whether or not it is the joint holder of the petroleum title.

Terms for the licence or concession are established in the Agreement for Joint Venture Participation ("**AJVP**"). The AJVP includes the description of the contract area and map, duration of the agreement and exploration phases, the work program and terms for any modification to the work program and the planning of the exploration phases, detailed environmental obligations and conditions for supplying to the national market. The contract will also specify accounting and financial procedures detailing the agreement for deposit in an escrow account, agreement relating to the acquisition of technical data, the right to profit oil, examples for calculating supplementary tax and income tax, stipulate the currency in which payments of tax, fees and fines shall be made, the method for calculating market price, fiscal and parafiscal charges that may be levied on the tax payer, types of amortization and the formula to calculate profitability.

Failure to perform the agreed work program will result in the associate companies of Petroguin and joint holders in the licence being denied a renewal or retention period and they shall be subject to pay the State the difference between the amount subscribed in the minimum technical and financial programs and the amount of expenditure actually incurred, as a penalty.

Following any hydrocarbon discovery allowing for the assumption that a commercially viable deposit exists, the holder(s) of an exploration licence must notify the Minister thereof and endeavour to demarcate the deposit. Upon declaration of commercially viable deposit the holders must apply for a concession and promptly carry out all work inherent to its development in order to produce it. Such a concession will be awarded provided that the applicant has fully discharged its legal and contractual commitments.

In the event that a discovery requires further appraisal to be deemed as commercial the contractor group may negotiate with the supervising Minister amendments to terms and conditions that may justify a declaration of commercial discovery and the granting of a provisional production licence. Appraisal work programs and budgets must be submitted to the management committee with 180 days from the date of declaration of a provisional commercial discovery. Within 12 months of completion of the appraisal work program the contractor group must declare commerciality of the discovery in writing. Upon declaration of commerciality the contractor group shall be jointly awarded a Production Concession pursuant to the Petroleum Law, Law No. 4/2014, provided that they have discharged all of their legal and contractual obligations.

Exploration licences may be revoked in the event of supervening technical incapability and / or financial incapacity of the contractor or contractor group, failure to comply with the minimum technical and financial programs, refusal to provide data and technical information, wilful and malicious submission of inaccurate technical data, or full or partial assignment to third parties of the exploration licence without relevant entities approval.

The holders of an exploration licence may relinquish all areas covered by the licence provided they have met all of their work program and financial obligations. On the date of cancellation of a licence the operator shall transfer to Petroguin all infrastructures, equipment and wells in a state of repair and operating condition needed in accordance with Good Oil Practice. If Petroguin so requires, the operator shall abandon the well or wells in accordance with Good Oil Practice.

Article 35, *Good Oil Practice*, of the Petroleum Law, Law No. 4/2014, states that exploration and production works of the contractor group must be conducted with due care for the protection of the environment and the conservation of natural resources. The contractor group must use techniques that comply with Good Oil Practice to prevent environmental damage arising, in whole or in part from the conduct of Petroleum Operations. Where environmental damage is unavoidable, the contractor group must mitigate impact on persons and property in accordance with any applicable Laws and Good Oil Practice.

Article 36, Environmental Study, of the Petroleum Law, Law No. 4/2014, stipulates the requirement for the contractor group to submit an environmental study including a background analysis to determine the existing situation and EIA.

Law No. 10/2010 The Environmental Assessment Law passed by the National People's Assembly on 24 September 2010 outlines the requirements of the environmental assessment as an essential preventive instrument in the environmental policy.

This law is a privileged method of promoting sustainable development, through a balanced management of natural resources, ensuring environmental quality is better protected and therefore contributing to a good quality of human life.

The environmental study shall be subject to binding opinion by the relevant national environmental authorities prior to granting the petroleum title.

8.3.3. Regulatory and environmental framework for The Gambia

Prospecting, exploration and production of hydrocarbons (upstream sector) in The Gambia is regulated by the Petroleum (Exploration, Development and Production) Act 2004. The objective of the Act is to ensure the efficient administration and management of the country's hydrocarbon resources for the maximum benefit of The Gambia people.

The Ministry of Petroleum and Energy's ("**MoPE**") main policy objectives in the Upstream Petroleum Sector is to provide the conducive policy and regulatory environment for the effective and efficient exploration, development, production, and utilization of petroleum resources of The Gambia. The Petroleum Commission under MoPE is mandated to regulate, oversee, and monitor activities in the petroleum upstream sector as stipulated in the Petroleum (Exploration, Development and Production) Act 2004.

The Gambia National Petroleum Company ("**GNPC**") is a recent entrant into the petroleum scene. The company is mandated to participate in the upstream and downstream operations in the sub-sector sector on the same terms as any oil company.

Pursuant to section 38 of the National Environment Management Act, a person shall not discharge any dangerous material, or substance, oil or mixture containing oil into any waters or any other segment of the environment except in accordance with regulations prescribed by the council. Section 38 provides for the polluter pays principle.

Section 59 of the National Environment Management Act provides that where an offence is committed by a corporate body and every director or officer who had knowledge or should have had knowledge of the commission of the offence, and who did not exercise all due diligence to ensure compliance with the Act are liable.

Section 5 of the Continental Shelf Act provides that any act or omission which takes place on, under or above an installation in a designated area or any waters within 500 meters of such an installation and would if taking place in any part of the Gambia, constitute an offence under the laws in force in that part shall be treated as taking place in that part.

Section 7 of the Continental Shelf Act states that if oil to which this section applies or any mixture containing not less than one hundred parts of such oil in a million parts of the mixture is discharged or escapes in any part of the sea from a vessel, from a pipeline or as the result of any operations for the exploration of the seabed and subsoil or the exploitation of their natural resources in a designated area, the owner or master of the vessel, the owner of the pipeline or, as the case may be, the person carrying on the operations commits an offence unless he or she proves, in the case of a discharge from a place in his or her occupation, that it was due to the act of a person who was there without his or her permission, (express or implied) or, in the case of an escape, that he or she took all reasonable care to prevent it and that as soon as practicable after it was discovered all reasonable steps were taken for stopping or reducing it.

8.3.4. Regulatory and environmental framework for Senegal

The Petroleum Code 2019, law no. 2019-03, establishes the rules pertaining to prospecting, exploration, development, exploitation, transport, storage of hydrocarbons as well as the liquefaction of natural gas. This law decrees that all petroleum in Senegal is the property of the Senegalese people. Furthermore, it defines that the State exercises sovereign rights for the above-mentioned activities.

The legislation determines that the Ministry of Energy ("**ME**") is the competent authority for its implementation and responsible for authorising activities under contracts for oil and gas prospecting, exploration and production. Furthermore, it recognizes the Senegal Petroleum Company ("**Petrosen**") as the National Oil Company, with at least 10% stake in all contracts. Petrosen is responsible for developing the Senegalese sedimentary basins and undertaking, at the request and on behalf of the State, activities of prospecting, research, exploitation, transport and marketing of unrefined liquid and gaseous hydrocarbons.

The Petroleum Code outlines requirements relating to transparency (in line with the Extractive Industries Transparency Initiative), local content, environmental protection, health and safety issues, among others. It also outlines pertaining sanctions and the means of administrative supervision.

This regulation does not contain specific restrictions regarding methane emissions. However, it states that oil and gas companies must take necessary measures to prevent and combat environmental pollution, acting in accordance with international industry practice and applicable national legislation.

This law replaced the Petroleum Code from 1998 (Law 98-05 of 8 January 1998).

The creation or modification of an Installation Classified for Environmental protection ("**ICPE**") is subject to an administrative authorisation before it can start operation. Depending on the type of procedure applicable to the installation (subject to declaration or to authorisation), in order to obtain the authorisation, the operator must register an ICPE file or an operating licence application.

Civil liability of a polluter arises in the absence of any fault when the property at the origin of damage caused is an establishment of "risk". Responsibility can be avoided only by proving that the pollution and its harmful effects are only due to a case of force majeure, fault of a third party or the victim, by action or inaction, has contributed to the damage.

Under Article 58 of the Petroleum Code, in case of expiry or termination of an agreement or a service contract and according to the provisions of Article 59 of the same code or in case of total or partial waiver, the State may exercise its right to recover the facilities and equipment related to petroleum operations abandoned area, unless such facilities and equipment are used by the owner for other oil operations in the territory of the Republic of Senegal.

If the State exercises its right of recovery, no compensation is paid to the owner.

If the State does not wish to return the facilities and equipment, the licensee must perform disassembly and removal as well as other works of abandonment; in case of failure by the licensees to fulfil such obligations, the Minister may direct the necessary procedures at the expense of the licensees.

8.3.5. Regulatory and environmental framework for Nigeria

Under the Nigerian Constitution and the Nigerian Petroleum Act of 1969 and its amendments, all minerals, mineral oils and natural gas in Nigeria are vested in the Federal Nigerian Government for the benefit of all Nigerians.

The Nigerian Petroleum Act is the primary legislation governing the development of petroleum in Nigeria. The Ministry of Petroleum Resources, which is headed by a Minister who acts for and on behalf of the Nigerian government, has the power to grant OELs (no longer granted in practice), OPLs, which give the holder an exclusive right to explore and prospect for petroleum in respect of an area, and grant OMLs, for the development and disposal of crude oil. The Minister’s consent is required for assignments of interests in OPLs and OMLs, and the Minister has the authority to issue regulations further to the Nigerian Petroleum Act. The Minister typically oversees the Nigerian industry through the Department of Petroleum Resources ("**DPR**"), which forms part of the Ministry of Petroleum Resources and is the technical department, regulatory and monitoring arm of the Ministry of Petroleum Resources.

The principal Government agencies responsible for petroleum matters are The Ministry of Petroleum Resources (the "**Petroleum Ministry**"), the DPR, the Nigerian Content Development and Monitoring Board, NNPC, which undertakes commercial ventures in the petroleum industry on behalf of the Federal Government, the Federal Ministry of Environment ("**FMOE**"), the Federal Inland Revenue Service ("**FIRS**") and the Niger Delta Development Commission ("**NDDC**").

The Petroleum Industry Bill ("**PIB**") is an all-encompassing bill which seeks to provide legal, governance, regulatory and fiscal framework for the Nigerian Petroleum Industry and development of Host Communities. The PIB, was passed by Nigeria´s Senate 1 July 2021.

The PIB contains 5 Chapters, 319 Sections and, 8 Schedules dealing with Rights of Preemption; Incorporated Joint Ventures; Domestic Base Price and Pricing Framework; Pricing Formula for Gas Price for the Gas Based Industries; Capital Allowances; Production Allowances and Cost Price Ratio Limit; Petroleum Fees, Rents and Royalty; and Creation of the Ministry of Petroleum Incorporated.

Among the notable provision of PIB is the creation of new governing bodies: The Nigerian Upstream Regulatory Commission, responsible for the technical and commercial regulation of upstream petroleum operations and The Nigerian Midstream and Downstream Petroleum Regulatory Authority, performing the same role for midstream and downstream petroleum operations, as well as a newly incorporated NNPC to replace existing NNPC.

The PIB also looks to shift fiscal take from profit taxation towards production and price based royalties. The current petroleum profit tax will be replaced with a new hydrocarbon tax and the application of companies' income tax (which previously did not apply to oil production). The hydrocarbon tax would apply to crude oil, condensates and natural gas liquids but not associated / non associated gas.

As part of its obligations, the Nigerian Upstream Regulatory Commission shall prescribe and allocate the domestic gas delivery obligation on a lessee. However, the Commission shall discontinue the imposition of domestic gas delivery obligations, where the Authority has determined that the natural gas market has attained full market status.

The PIB also introduces obligations regarding the development of host communities to foster sustainable prosperity within host communities and to provide direct social and economic benefits from petroleum operations to host communities. It also seeks to enhance peaceful and harmonious co-existence between licensees or lessees and host communities. The PIB mandates that holders of an interest in a petroleum prospecting licence or petroleum mining lease or a holder of an interest in a licence for midstream petroleum operations, whose area of operations is located in or appurtenant to any community or communities), shall incorporate a trust for the benefit of the host communities for which it is responsible. The funds of the host communities' development trust created pursuant to this Act shall be exempted from taxation.

The local content in oil and gas projects is defined under the Nigerian Oil and Gas Industry Content Development Act (the "**Local Content Act**"), which was promulgated in April 2010. Prior to 2010, there was no legislation wholly dedicated to the Nigerian content in the oil and gas industry although pocket provisions existed like the Petroleum Act of 1969 and certain NNPC directives. The new Local Content Act is partially premised on the temporary directives of NNPC for the oil and gas industry.

The Local Content Act is the principal law that provides for the development, supervision, coordination, monitoring and implementation of Nigerian content in the Nigerian oil and gas industry. Compliance with the Local Content Act is monitored by the Nigerian Content Development Monitoring Board.

The Local Content Act defines the Nigerian content or "local content", as the quantum of composite value added or created in the Nigerian economy by a systematic development of capacity and capabilities through the deliberate utilization of Nigerian human and material resources and services in the Nigerian oil and gas industry.

The Nigerian content focuses on the promotion of value addition in Nigeria through the utilization of local raw materials, products and services in order to stimulate growth of indigenous capacity. The Local Content Act prescribes minimum thresholds for Nigerian content in various segments of the Nigerian oil and gas industry. The Local Content Act requires that Nigerian indigenous operators be given first consideration when contracts are awarded for oil blocks, licences and all projects, that services provided and goods manufactured in Nigeria be given priority or preference and finally that qualified Nigerians are considered first for employment and training.

The Local Content Act applies to all the players in the oil and gas industry, such as the NNPC operators, contractors, subcontractors, alliance partners and other entities involved in any project, operation, activity or transaction in the Nigerian oil and gas industry. It applies to both indigenous and to international / multinational oil companies.

An employment and training program is required for every project to be executed in the Nigerian oil and gas industry. To this end, there is a requirement for Nigerians to be considered first for employment and training in any project. Where such

Nigerians cannot be employed for lack of training, the act requires that reasonable efforts be made to provide such training within or outside Nigeria. The Local Content Act makes a provision for a succession plan for every position not held by Nigerians. The plan must provide for Nigerians to understudy each incumbent expatriate for a maximum period of four (4) years, after which the position shall be transferred to a Nigerian. However, a maximum of 5% of management positions can be held by expatriates.

Contracts with a total budget exceeding USD 100 million are to contain a labour clause mandating the use of a minimum percentage of Nigerian labour in specific cadres as may be stipulated by the Nigerian Content Development Monitoring Board. Nigerians are to occupy all junior and intermediate positions.

Further, the Petroleum (Drilling & Production) Regulations ("**PDPR**"), issued pursuant to the Nigerian Petroleum Act, regulates operational aspects of the drilling and production of crude oil. The PDPR set out fees, rents and rates of royalties payable (depending on the location of the concession, royalty rates range from 0% in deep offshore areas to 20% onshore) by a licensee or lessee under the Nigerian Petroleum Act. In addition, licensees and lessees are obligated to obtain permits and licenses before engaging in most activities in furtherance of petroleum operations under the relevant OPL or OML and also have reporting obligations. The compliance of PDPR is primarily undertaken through the Operator on the license.

There are also the Crude Oil (Transportation and Shipment) Regulations which regulate the transportation and shipment of crude oil after production. Adherence of these rules is more so the responsibility of the operator and offtaker.

Petroleum operations and activities are regulated primarily by federal agencies, although some state Governments and local Governments also have regulations and by-laws that affect activities in the oil and gas industry.

A number of national and international regulations guide oil and gas exploration and production activities in Nigeria. The first major national environmental guidelines for oil and gas exploration and production activities came into effect in 1981 when DPR issued interim guidelines and standard on monitoring, treatments and disposal of effluents from the petroleum industry. Regulations existing before this time were not specific environmental acts or laws; they were limited to statutory provisions that requested voluntary environmental protection efforts from the operators. In 1991, the sustainable Environmental Guidelines and Standards for the Petroleum Industry in Nigeria ("**EGASPIN**") replaced the 1981 interim guidelines. In 2002, a revised EGASPIN was published, replacing an unpublished 1999 version. Oil companies are working in compliance with the 2002 requirements.

Regulations relating specifically to the EIA of the proposed Aje FDP are the EGASPIN by DPR (2002) and Federal Ministry of Environment, ("**FMEnv**"), formally Federal Environmental Protection Agency (FEPA), environmental guidelines and standards, including Environmental Impact Assessment Act No. 86 of 1992. The Aje Field EIA was prepared pursuant to EIA procedural requirements of the DPR and FMEnv guidelines. There are, however, other regulatory requirements that also apply to the project.

8.4. Licenses and concessions

PNGF Sud

The PNGF Sud licenses consisting of 3 production sharing contracts, Tchendo II, Tchibouella II and Tchibeli-Litanzi II, were effective as of 1 January 2017 and have a duration period of 20 years with the option of a 5-year extension.

PNGF Sud Republic of Congo			
Tchendo II	**Period 1**	**Period 2**	**Period 3**
Production and time tranches	**01.01.2017, < 1.5 MMbbls cum. prod.**	**6 years**	**Thereafter**
Price Ceiling	40	90	40
Cost stop	50%	50%	50%
Production tranches	**< 15 MMbbls cum. prod.**		**> 15 MMbbls cum. prod.**
Profit oil for contractor	50%		30%
Super profit for oil contractor	34%		30%
Royalty	15%		15%
Tchibouela II	**Period 1**	**Period 2**	**Period 3**

Production and time tranches	01.01.2017, < 10 MMbbls cum. prod.	6 years	Thereafter
Price Ceiling	40	90	40
Cost stop	50%	55%	50%
Production tranches	**< 20 MMbbls cum. prod.**		**> 20 MMbbls cum. prod.**
Profit oil for contractor	50%		45%
Super profit for oil contractor	34%		34%
Royalty	15%		15%

Tchibeli-Litanzi II	Period 1	Period 2	Period 3
Production and time tranches	**01.01.2017, < 2 MMbbls cum. prod.**	**5 years**	**Thereafter**
Price Ceiling	40	90	40
Cost stop	50%	50%	50%
Production tranches	**< 15 MMbbls cum. prod.**		**> 15 MMbbls cum. prod.**
Profit oil for contractor	50%		50%
Super profit for oil contractor	30%		34%
Royalty	15%		15%

Sinapa and Esperança

As of late April 2021, the Group has become the Operator of the Sinapa (Block 2) & Esperança (Blocks 4A & 5A) licences following regulatory approval in Guinea-Bissau being granted for the purchase by the Company of SPE Guinea Bissau AB[19] from Svenska Petroleum Exploration AB.

Sinapa (Block 2) & Esperança (Blocks 4A & 5A) Guinea-Bissau

Expiry	Royalty			Tax
2 October 2023	**Shallow water (< 200m)**		**Deepwater (> 200m)**	
	Production	**Rate**	2.5%	35%
	0-10,000 Bopd	5%		
	10,000-20,000 Bopd	8.75%		
	> 20,000 Bopd	12.5%		

A4

The Gambian Licences were originally awarded to Buried Hill on 8 September 2006. The Group acquired a 60% interest in the Gambian blocks in August 2010 from Buried Hill under a farm-in agreement. The Group subsequently became 100% owner and operator in November 2014.

Following the settlement with the government of The Gambia on 19 September 2019, the A4 license was re-awarded to PetroNor under new terms.

A4 The Gambia

Expiry		Royalty	Tax
30 years	**Daily production**	**State take**	
	0-149,999 Bopd	5%	31%
	150,000-974,999 Bopd	7.5%	
	> 1,000,00 Bopd	6%	
	Satellite	25%	

SOSP and ROP

Although currently in arbitration, the Company reserves its rights in the exploration blocks of ROP and SOSP in Senegal. The Senegal Licences are governed by individual PSCs (the "Senegalese PSCs") between the licensees and Senegalese

[19] As of 4 June 2021, SPE Guinea Bissau formally changed its name to PetroNor E&P AB.

government and two JOAs entered into between African Petroleum Senegal and Petrosen on 25 November 2011. Petrosen holds 10% in the Senegalese PSCs with the option to increase to 20% when the exploitation authorisation becomes effective.

The Group and the Senegal Government have been in arbitration since 2018 regarding the Senegal PSCs. As announced 5 May 2020, the Company reached a mutual agreement with the Government of Senegal to suspend the Arbitration related to the Senegal Licences for a period of six months with a view to reaching a satisfactory outcome for all parties, and a formal request has been lodged with ICSID to suspend the process. Subsequently, the parties further extended the suspension by an additional three months as announced 30 October 2020, and with further two months as announced 2 February 2021. On 5 April 2021, the Company announced that throughout the prolonged suspension period, the Company has made significant efforts to reach a mutually beneficial solution and has held numerous progressive meetings with the relevant authorities to no avail. Please refer to section 8.10 "Legal proceedings" for further details.

<u>OML-113</u>

The license was initially awarded as OPL-309 in 1991 and was converted into an oil mining license in 1998, namely OML-113. In 2019, the license was granted a 20-year extension based on the development of a significant gas discovery.

OML-113 Nigeria			
Subject	**Current Royalty Rates (Petroleum Act)**		**Legal Provision**
Oil and condensate	10% plus royalty by price below		Regulation 61(a) and (d), Petroleum (Drilling and Production) Regulations (2020 Amendment)
	Oil price	**Rate**	
	20-60 USD/bbl	2.5%	
	60-100 USD/bbl	4%	
Gas		5%	Regulation 61(e)(ii), Petroleum (Drilling and Production) Regulations (2020 Amendment)
VAT	7.5%		
Petroleum Profits Tax Oil (PPT)		50%	
Petroleum Profits Tax Gas (PPT)		30%	

8.5. History of the Group

PetroNor E&P Limited was incorporated in Australia on 16 May 2007 under the name Global Iron Limited ("**Global Iron**") and admitted to the official list of the Australian Securities Exchange ("**ASX**") on 16 October 2007. Until June 2010, Global Iron's principal activity was mineral exploration and evaluation.

The oil & gas business of the group dates back to June 2005 when following an international bidding round, private company European Hydrocarbons Limited ("**EHL**"), was awarded 75 per cent working interest in licences LB-09 and LB-08 offshore Liberia.

In June 2010, EHL through a reverse take-over of Global Iron, rebranded the enlarged business African Petroleum Corporation Ltd ("**APCL**"). APCL was admitted to the official list on the National Stock Exchange of Australia ("**NSX**") on 30 June 2010 and subsequently delisted from the ASX following application from the Company on 3 September 2010. APCL's securities were admitted for trading on the Oslo Axess (now called Oslo Euronext Expand) on 30 May 2014 and the Company voluntarily de-listed from the NSX with effect from 4 January 2016. Between 2010 and 2019, APCL periodically issued new equity to raise finance to fund the exploration licence portfolio across sub–Saharan Africa that it managed, and during this time drilled three exploration wells in Liberia and participated in another well in Côte d'Ivoire.

Separately in 2016, private company Hemla E&P Congo SA ("**HEPCO**") was awarded 20% interest in the PNGF Sud producing licence in Congo Brazzaville. The largest shareholder in HEPCO was Hemla Africa Holding AS ("**HAH**"). In 2017, the intermediary holding company, PetroNor E&P Ltd (Cyprus) was established and inserted above HAH by the HAH shareholders, with ambition to grow the business through M&A activities in addition to the operations in Congo Brazzaville. To support the planned growth and enable PetroNor E&P Ltd (Cyprus) to raise funds publicly, the business merged with APCL on 30 August 2019 by a reverse takeover. The listed company APCL then changed its name to PetroNor E&P Limited on 11 September 2019.

Before the reverse take-over in 2019, the Company had a share capital of app. 155.47m shares and 816.20m shares were issued as part of the reverse take-over. Further another 309.09m shares were issued in a private placement in 2021 and approximately 46.23 million shares in a subsequent repair offering. The current shareholdings are displayed in Section 14.5 "Ownership structure" below.

On 24 February 2022, a court approved scheme of arrangement under Australian laws was implemented. After approval of the scheme of arrangement, (1) share in PetroNor Australia was exchanged for one (1) share in the Company, being the Share Swap. As such, and under the Australian scheme, all of the shares held by PetroNor E&P Ltd. (Australia) shareholders were transferred to the Company. The shareholders are thus, in all material respects, identical before and after the transaction. Therefore this will be treated as a continuance of business under the Company (being the new listing entity).

The Share Swap was from a Norwegian law point of view carried out in the following corporate steps: the Company's general resolved to (i) reduce the Company's share capital to zero and (ii) immediately after increase the share capital, where share certificates in PetroNor Australia were used as contribution in kind to increase the share capital and thereby issuing shares to the original holders of PetroNor Australia shares. The share capital changes is expected to be recorded in the Norwegian Register of Business Enterprises on or about 21 December 2022. The new shares will then be immediately transferred to the shareholder entitled to shares in the Company.

On 24 February 2022, the shares in PetroNor Australia were delisted in conjunction with the Listing.

8.6. Competitive strengths

The Management team at PetroNor has in-depth industry experience from the oil and gas upstream industry. Together they have built a broad network of industry contacts, and developed strong relationships with governments, institutions and trusted partners fostered over many years of valued collaboration. The Company has an experienced team of technical, commercial and support staff and the ability to scale up the workforce for projects from a deep talent pool in Norway and the UK. The Company’s flat structure and assumed strict focus on execution and delivery enable it to move rapidly to take advantage of opportunities. With many years of experience working on the Norwegian continental shelf, the management and technical staff are able to apply and utilise cutting edge industry innovations and technologies to PetroNor's projects globally in order to maximise their potential value.

With access to the Norwegian equity market with sophisticated investors in the energy sector coupled with a strong cornerstone investor from Abu Dhabi, the Company is well positioned to access capital both for smaller and larger transaction opportunities.

8.7. Strategy and objectives

The Company’s business objectives are to grow its daily production levels to 30,000 boepd and increase the Company’s 2P reserves to 300mmboe over the next few years. The Company adheres to the view of United Nations that gas holds an important role as a transition fuel for Africa in the coming years and this is an important element of the basis for the strategic choices of the Company.

The Company’s business strategy is to maintain a robust capital structure with low financial leverage and utilize its cash flow generated from producing assets to fund organic growth initiatives. This is coupled with support from strategic shareholders providing access to further growth capital and co-operation with financial partners including off-take counter parties, to sponsor transformational and accretive M&A deals. The Company aims to lever the Management's experience and network within the core focus region of Africa to access and select opportunities with upside potential.

The Company is today operator on the exploration licenses and will build future production operations around the Management's North Sea operational experience. The Company regards the main challenge to reach its objectives of growth is access to capital, both equity and debt, and the competitiveness of the Company in any potential bidding process. Another important challenge going forward is access to human capital required to plan and develop any such complex project as an oil and gas development program is. The Company has strong focus on health, safety and environment (HSE) in any of its operations and established specific project routines for each project where the Company is the operator. The specific project procedures build on the general corporate governance plan of the Company, as further described in Section 13.12 "Corporate governance".

Local partnerships are a fundament for the operations of the Company and a part of its core values. Additional value is assumed to be realized for local stakeholders through transfer and implementation of technologies and expertise, especially within resource management such as combined water-gas injection technology, application of advanced well completion technology, monetization of gas through small scale solutions for utilization of gas for power generation or to associated gas products to serve the local market. Through our field operations, the Company aims to support local growth through local employment and on-the-job training combined with experience transfer programs. The Company built its operational philosophy on the strict adherence to both health, safety and environment in extraction of natural resources from the North Sea operational experience.

8.8. Important events

The table below provides an overview of key events in the history of the Company:

YEAR	KEY EVENTS
2007	Global Iron established *Renamed African Petroleum Corporation Ltd in 2010, further renamed PetroNor E&P Ltd in 2019*
2010	Reverse takeover of Global Iron by APCL and IPO on the National Stock Exchange of Australia
2010-2013	APCL acquired > 17,000km^2 of multi-client 3D seismic data, across a portfolio of 10 blocks in five West African countries
2011-2013	APCL drilled three operated wells in Liberia resulting in the Narina-1 well discovery
2014	APCL participated in Ayame-1 well in deepwater Côte d'Ivoire
2014	APCL IPO on the Oslo Stock Exchange
2016	Hemla E&P Congo is awarded PNGF Sud asset in Congo Brazzaville
2017	PetroNor E&P Ltd (Cyprus) is established
2017	APCL sign heads of terms agreement for The Gambia/Senegal farm-in
2018	APCL arbitration initiated for The Gambia and Senegal licences
2019	Business combination between PetroNor and APCL to create full-cycle listed E&P company
2019	Agreement to acquire Panoro Energy's interest in OML-113 licence, Nigeria,
2019	Agreement to create a SPV with Yinka Folawio Petroleum to hold the interests in OML-113 license in Nigeria
2020	Resolution of The Gambia dispute and reinstatement of the A4 licence
2020	Acquisition of Svenska Petroleum Exploration's interests in the Sinapa and Esperança licences in Guinea-Bissau, through acquisition of SPE GB AB.
2021	Return to arbitration in Senegal
2021	PetroNor increase indirect ownership percentage of PNGF Sud asset through purchase of non-controlling interest of subsidiary HAH from Symero Ltd
2021	One year extension Gambia Block A4 farm-out period

2022	PetroNor Redomiciles to Norway from Australia through a court approved Scheme of Arrangement and expects the shares of the Company to be admitted to Listing on or about the date of this Prospectus

8.9. IT and infrastructure

The groups IT strategy is built around the ability to deliver required access and resources independent of physical location, and to quickly be able to adapt and incorporate to new solutions.

- Operational simplicity and cost-efficient solutions
- Maintain high IT security
- High-up time access for all employees
- Access to skills and services which are independent of location to support the multiple locations of the group
- Application of cloud-based standard software tools where applicable and avoid "over-engineering" of solutions
- Application of cloud-based specialist tools where required

The company uses cloud-based systems from a number of different suppliers which provides the required flexibility for the employees. The group uses standardized platforms which allows for flexibility with respect to hardware. The group emphasize to have an open-access data philosophy to strive to enhance team-work and cross-discipline contribution, however, combined with a strict access control for sensitive information as required per the GDPR. The company aim to maintain a high IT security through internationally recognized procedures combined with physical measures. As the company continuous to grow, the IT strategy will enable the company to readily scale and adapt its IT infrastructure to meet new requirements.

8.10. Legal proceedings

As at the date of this Prospectus, the Group is involved, inter alia, as the claimant in ICSID arbitration case ARB/18/24 in relation to its 90% interest in the Rusfique Offshore Profond Block and the Senegal Offshore Sud Profond block licences in Senegal, an arbitration case which resumed in April 2021 after a prolonged suspension period. The Group is dependent on a successful outcome of the negotiation with the Senegalese government or a successful outcome in the arbitration case in order to have its respective licences re-instated or obtained with an acceptable commercial outcome The Group has no control over the outcome of the arbitration case. Should the outcome of the negotiations or the arbitration case be unfavourable to the Group, this will have a material adverse effect on the Group's financial condition, business, cash flow, prospects and/or results.

Hemla African Holding AS is in dispute with a former employee of HEPCO concerning a claim for (indirect) ownership in HEPCO. The former employee argues that he is entitled to an (indirect) ownership position in HEPCO, including past dividends taking such ownership position into account. The former employee has filed the claim before the Commercial Court in Pointe-Noire. He has also filed a petition for arrest relating to HAH's shares in HEPCO. The claim is based on an alleged promise of shares in HEPCO. The claim is disputed.

In January 2021, HAH gained control of an additional 9,900 shares in HEPCO, shares previously held by the minority shareholder, MGI International S.A. ("**MGI**"), and resultantly HAH increased its net ownership in the PNGF Sud licenses from 14.85% to 16.83% and in the PNGF Bis licenses from 20.79% to 23.56%. This follows a default concerning a debt arrangement between HAH as lender and MGI as borrower on the basis of a transfer by MGI of 15,000 of its shares in HEPCO to Marcel Okongo, and where 9,900 shares were pledged in favour of HAH. The default has been disputed by MGI and has been subject to several court proceedings in the Republic of Congo, all of which have resulted in rulings in the favour of HAH. It is expected that MGI will make a further appeal, and with the final outcome and timing of such further appeal ruling being uncertain. Should MGI appeal and the outcome of such appeal process be in favour of MGI, it is expected that HAH would have to transfer ownership of the 9,900 shares in HEPCO back to MGI. While there are no legal restrictions on the ability of HAH to exercise ownership rights over the shares in question, it cannot be ruled out that there will be additional legal processes and action taken by MGI that could influence HAH's ownership to these shares.

Other than described above, the Group is not aware of any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened) in the previous 12 months which could have, or have had in the recent past, significant effects on the Group's financial position or profitability.

8.11. Insurance

The Group currently maintains insurance coverage of the type and in amounts that it believes to be customary in the industry, all subject to certain limitations, deductibles and caps. The CEO and Board of Directors are also covered by directors' and officers' liability insurance. However, no assurance can be given that the Group will not incur any damages that are not covered by its insurance policies or that exceed the coverage limits of such insurance policies.

8.12. Material contracts

Other than the PSCs described in Section 8.2 "The Group's business activities", the loan agreements described in Section 12.9.5 "Financing arrangements" and the Aje Transaction described in Section 11.2 "Aje Transaction", neither the Company nor any other member of the Group has entered into any other material contracts outside the ordinary course of business for the two years prior to the date of this Prospectus.

Further, and other than the above and as described herein, the Group has not entered into any other contract outside the ordinary course of business that contains any provision under which any member of the Group has any obligation or entitlement that is material to the Group as of the date of this Prospectus.

8.13. Dependency on patents, licences, contracts etc.

Other than the PSCs described in Section 8.2 "The Group's business activities", the licenses described in Section 8.13 "Licenses and concessions" and the loan agreements described in Section 12.9.5 "Financing arrangements", no patents or licenses, industrial, commercial or financial contracts or new manufacturing processes is material to the Group's business or profitability.

9. CAPITALISATION AND INDEBTEDNESS

9.1. Introduction

The information presented below should be read in conjunction with the other parts of this Prospectus, in particular Section 10 "Selected Financial information and Other information", Section 11 "Operating and Financial Review", and the Group's Financial Statements and Interim Financial Statements and the notes related thereto included in Appendix B to E to this Prospectus.

This Section 9 "Capitalisation and indebtedness" provides information about the Group's unaudited capitalisation and net financial indebtedness on an actual basis as at 30 November 2021 and, in the "As adjusted " column, the Group's unaudited consolidated capitalisation and net financial indebtedness on an adjusted basis to show the estimated effects of the transactions detailed in the unaudited pro forma financial information (see Section 11 "Unaudited pro forma financial information").

In relation to the Panoro Agreement, the consideration payable by the Group is (i) issue of shares in the Company for USD 10 million and (ii) a contingent payment obligation after PetroNor has recovered all costs related to the accumulated investments incurred after the Completion Date equal to USD 0.10 per 1,000 Cubic Feet of Aje Gas sales volume limited to USD 16.67 million. The capitalisation has been adjusted for the receipt of the transaction approval by the Nigerian Department of Petroleum Resources and the assumption that the Company has issued USD 10 million in shares, but no adjustment has been made for the contingent payment obligation due to the uncertainty of this performance measure occurring.

As the Guinea-Bissau Transaction completed in May 2021 and no adjustments are required to the capitalization and indebtedness, as it is already ready represented in the 30 November 2021 figures.

Other than as set forth above, there has been no material change to the Group's capitalisation and net financial indebtedness since 30 November 2021.

9.2. Capitalisation

The following table sets forth information derived from the Group’s internal management accounts as at 30 November 2021 adjusted for adjustments to reflect the capitalisation as at the date of this Prospectus:

In USD Million	**As at 30 November 2021 Unaudited** [a]	**Adjustments Unaudited** [b]	**As adjusted Unaudited**
Guaranteed	-	-	-
Secured	10.0	-	10.0
Unguaranteed/unsecured	24.5	-	24.5
Total current debt (excluding portion of non-current debt:	**34.5**	**-**	**34.5**
Guaranteed	-	-	-
Secured	-	-	-
Unguaranteed/unsecured	20.1	-	20.1
Total non-current debt (excluding current portion of non-current debt)	20.1	-	20.1
Total debt (A)	54.6	-	54.6
Share capital	62.2	10.0	72.2
Legal reserves	-	-	-
Other reserves	(12.2)	-	(12.2)
Shareholder equity (B)	**50.0**	**10.0**	**60.0**
Total capitalisation (A) + (B)	**104.6**	**10.0**	**114.6**

[1)] Secured/guaranteed current debt of USD 10 million consists of the financial statement line item "Loans and borrowings" of USD 10 million. The interest-bearing financial liabilities are secured as follows: assignment of receivables by subsidiary company HEPCO; pledge over one of the bank accounts of subsidiary company HAH; pledge over one of the bank accounts of subsidiary company HEPCO; pledge over shares in subsidiary companies, HAH and HEPCO; assignment of inter-company loan agreement between HAH and HEPCO; and corporate guarantees by the parent company and its subsidiaries PetroNor E&P Ltd. Cyprus and HEPCO.

2) Unguaranteed/Unsecured current debt of USD 24.6 million consists of the financial statement line items "Trade and other payables" of USD 24.5 million and "Lease liability" of USD 0.1 million.

3) No secured non-current debt remains outstanding

4) Unguaranteed/Unsecured non-current debt of USD 20.1 million consists of the financial statement line items "Loans and borrowings" of USD 3.9 million and "Provision" of USD 16.2 million

5) Share capital of USD 62.2 million consists of 1,326,991,006 ordinary shares.

6) Legal reserves are nil.

7) Other reserves of USD 12.2 million consists of retained earnings of USD 10.9 million and foreign currency translation reserves of USD 1.3 million.

(b) The data set forth in this column reflects the adjustments as explained below:

1) The Panoro Agreement was subject to approval by the Nigerian Department of Petroleum Resources and the consideration payable by the Group is (i) issue of shares in the Company for USD 10 million and (ii) a contingent payment obligation after PetroNor has recovered all costs related to the accumulated investments incurred after the Completion Date equal to USD 0.10 per 1,000 Cubic Feet of Aje Gas sales volume limited to USD 16.67 million. The capitalisation has been adjusted for the receipt of the transaction approval by the Nigerian Department of Petroleum Resources and the assumption that the Company has issued USD 10 million in shares, but no adjustment has been made for the contingent payment obligation due to the uncertainty of this performance measure occurring.

9.3. Net financial indebtedness

The following table set forth information about the Group's combined net financial indebtedness as at 30 November 2021, derived from the Group's management accounts.

No adjustements in the period from 30 November 2021 to the date of this Prospectus is deemed needed to have been made for the net financial indebtedeness of the Group.

All figures in USD millions		As at 30 November 2021 Unaudited [(a)]
(A)	Cash	36.8
(B)	Cash equivalents	-
(C)	Other current financial assets	-
(D)	**Liquidity (A)+(B)+(C)**	**36.8**
(E)	Current financial debt (including debt instruments, but excluding current portion of non-current financial debt)	0.1
(F)	Current portion of non-current financial debt	10.0
(G)	**Current financial debt (E)+(F)**	**10.1**
(H)	**Net current financial indebtedness (G)-(D)**	**(26.7)**
(I)	Non-current financial debt (excluding current portion and debt instruments)	3.9
(J)	Debt instruments	-
(K)	Non-current trade and other payables	16.2
(L)	**Non-current financial indebtedness (I)+(J)+(K)**	**20.1**
(M)	**Total financial indebtedness (H)+(L)**	**(6.6)**

(a) The data set forth in this column are derived from the Financial Statements

[1] Cash of USD 36.8 million consists fully of the financial statement line items "Cash and cash equivalents".

[2] Current financial debt of USD 0.1 million consists of the financial statement line item "Lease liability" of USD 0.1 million.

[3] Current portion of non-current financial debt of USD 10 million consists of the financial statement line item "Loans and borrowings" of USD 10.0 million.

[4] Non-current financial debt of USD 3.9million consists of the financial statement line item "Loans and borrowings" of USD 3.9 million.

[5] Non-current trade and other payables if USD 16.2 million consists of the financial statement line item "Provisions" of USD 16.2 million.

9.4. Contingent and indirect indebtedness

The Group has no material contingent or indirect indebtedness as of the date of this Prospectus except for the contingent payment obligation under the Panoro Agreement, as further described in Section 9.2. The payment is contingent on the completion of the Panoro Agreement and after PetroNor has recovered all costs related to the accumulated investments incurred after the completion date equal to USD 0.10 per 1,000 Cubic Feet of Aje Gas sales volume limited to USD 16.67 million.

9.5. Working capital statement

The Company is of the opinion that the working capital available to the Group is sufficient for the Group's present requirements for the period covering at least 12 months from the date of this Prospectus.

10. SELECTED FINANCIAL AND OTHER INFORMATION

10.1. Introduction and basis for preparation

The following selected financial information has been extracted from PetroNor Australia's financial statements and Financial Information.

The selected financial information included herein should be read in connection with, and is qualified in its entirety by reference to, the PetroNor Norway Financial Statements and Financial Information included in Appendix B to E and should be read together with Section 11 "Operating and Financial Review".

The PetroNor Norway Financial Statements and the Financial Statements have been prepared in accordance with IFRS. The Company's Interim Financial Statements have been prepared in accordance with IAS 34.

The Financial Statements have been audited by BDO Audit (WA) Pty Ltd, a member firm of BDO International Ltd, 38 Station Street, Subiaco, Western Australia 6008. BDO Audit (WA) Pty Ltd is a Chartered Firm with the Institute of Chartered Accountants Australia.

The PetroNor Norway Financial Statements have been audited by BDO AS, a member firm of BDO International Ltd with registered adress at Munkedamsveien 45A, 0250 OSLO, Norway.

10.2. Summary of accounting policies and principles

For information regarding accounting policies and the use of estimates and judgements, please refer to the notes of the annual Financial Statements for 2020 and to the notes of the PetroNor Norway Financial Statements.

10.3. Consolidated historical financial information

The following tables present selected financial information for the Company that has been derived from the PetroNor Norway Financial Statements and Financial Information.

10.3.1. Statement of profit and loss and other comprehensive income

USD '000	**Six months ended**		**Year ended 31 December**		
	30 June 2021	**30 June 2020**	**Dec-20**	**Dec-19**	**Dec-18**
	(unaudited)	**(unaudited)**	**(audited)**	**(audited)**	**(audited)**
	$'000	*$'000*	*$'000*	*$'000*	*$'000*
Revenue	48,174	30,263	67,543	102,760	101,069
Cost of sales	(16,832)	(12,673)	(25,885)	(37,207)	(41,577)
Gross profit	**31,342**	**17,590**	**41,658**	**65,553**	**59,492**
Other operating income	357	5	45	9	491
Exploration expenses	(1,259)	-	-	-	-
Administrative expenses	(5,314)	(5,947)	(12,376)	(19,793)	(10,090)
Profit from operations	**25,126**	**11,648**	**29,327**	**45,769**	**49,893**
Finance expense	(1,626)	(1,158)	(2,606)	(1,822)	(1,623)
Foreign exchange gain / (loss)	19	524	1,507	(440)	(88)
Share based payment	-	-	-	(19,374)	-
Profit/(loss) before income tax	**23,519**	**11,014**	**28,228**	**24,133**	**48,182**
Tax expense	(14,654)	(8,083)	(17,078)	(29,894)	(31,124)
Profit/(loss) for the period	**8,865**	**2,931**	**11,150**	**(5,761)**	**17,058**
Other comprehensive income					
Exchange gains/(losses) arising on translation of foreign operations	(29)	(502)	(1,050)	-	-
Total comprehensive income /(loss)	**8,836**	**2,429**	**10,100**	**(5,761)**	**17,058**
Profit/(loss) for the period attributable to:					
Owners of the parent	3,029	(439)	2,373	(13,364)	7,838
Non-controlling interests	5,836	3,370	8,777	7,603	9,220
	8,865	**2,931**	**11,150**	**(5,761)**	**17,058**
Total Comprehensive (Loss) / Income Attributable to:					
Owners of the parent	3,258	(755)	1,417	(13,364)	7,838
Non-controlling interests	5,578	3,184	8,683	7,603	9,220
	8,836	**2,429**	**10,100**	**(5,761)**	**17,058**
	USD cents	USD cents	USD cents	USD cents	USD cents
Basic profit / (loss) per share	0.30	(0.05)	0.24	(1.54)	0.96
Diluted profit / (loss) per share	0.30	(0.05)	0.24	(1.54)	0.96

10.3.2. Statement of financial position

USD '000s	**As at 30 June 2021 (unaudited)** *$'000*	**As at 30 June 2020 (unaudited)** *$'000*	**As at 31 Dec 2020 (audited)** *$'000*	**As at 31 Dec 2019 (audited)** *$'000*	**As at 31 Dec 2018 (audited)** *$'000*
ASSETS					
Current Assets					
Inventories	5,724	3,852	3,578	3,233	2,570
Trade and other receivables	8,506	30,088	9,397	24,772	28,210
Cash and cash equivalents	20,444	11,113	14,113	27,891	7,926
	34,674	**45,053**	**27,088**	**55,896**	**38,706**
Non-current assets					
Property, plant and equipment	22,592	23,085	23,695	22,587	12,580
Intangible Assets	6,890	4,326	6,935	4,691	5,565
Other Receivables	23,679	-	21,260	-	-
	53,161	27,411	51,890	27,278	18,145
Total assets	**87,835**	**72,464**	**78,978**	**83,174**	**56,851**
Liabilities					
Current Liabilities					
Trade and other payables	15,695	24,087	22,408	34,602	9,653
Loans and borrowings	8,000	-	4,000	12,941	5,000
	23,695	**24,087**	**26,408**	**47,543**	**14,653**
Non-current liabilities					
Provisions	15,805	15,000	15,362	14,373	13,496
Loans and borrowings	10,078	14,840	14,912	-	2,083
	25,883	**29,840**	**30,274**	**14,373**	**15,579**
Total Liabilities	49,578	53,927	56,682	61,916	30,232
NET ASSETS	**38,257**	**18,537**	**22,296**	**21,258**	**26,619**
Issued Capital and reserves attributable to the owners of the parent	28,138	17,735	17,735	17,735	120
Foreign currency translation reserve	(727)	(316)	(956)	-	-
Retained earnings	(5,824)	(11,665)	(8,853)	(11,226)	13,688
	21,587	**5,754**	**7,926**	**6,509**	**13,808**
Non-controlling interest	16,670	12,783	14,370	14,749	12,811
TOTAL EQUITY	**38,257**	**18,537**	**22,296**	**21,258**	**26,619**

10.3.3. *Statement of cash flows*

USD '000	For the period ended 30 June 2021	For the period ended 30 June 2021	For the year ended 31 December 2020	For the year ended 31 December 2019	For the year ended 31 December 2018
	(unaudited)	**(unaudited)**	**(audited)**	**(audited)**	**(audited)**
	$'000	*$'000*	*$'000*	*$'000*	*$'000*
OPERATING ACTIVITIES					
Total comprehensive (loss) / income for the period	8,836	2,429	10,100	(5,761)	17,058
Adjustments for:					
Income Tax Expense	14,654	8,083	17,078	29,894	31,124
Depreciation & amortization	2,333	1,946	4,475	3,323	3,206
Amortization of right-of-use asset	85	-	169	-	-
Equity raise	-		-	16,433	-
Write off of Goodwill	-		-	9	-
Unwinding of discount on decommissioning	497	467	934	877	824
	26,405	**12,925**	**32,756**	**44,775**	**52,212**
(Increase)/decrease in trade and other receivables	(2,387)	(2,547)	729	6,724	(9,807)
Increase in advance against decommissioning cost	-	(3,039)	(6,614)	(3,286)	(11,360)
Increase in Inventories	(2,146)	(619)	(345)	(663)	(201)
(Decrease)/increase in trade and other payables	(6,685)	(10,246)	(12,363)	24,950	(784)
Cash (used in)/generated from operations	**(11,218)**	**(3,526)**	**(18,593)**	**27,725**	**(22,152)**
Income taxes paid	(14,654)	(8,083)	(17,078)	(29,894)	(31,124)
Net cash flows from operating activities	**533**	**(11,609)**	**(2,915)**	**42,606**	**(1,064)**
Investing activities					
Purchase of property plant and equipment	(1,385)	(2,079)	(4,615)	(12,466)	(4,037)
Acquisition of interest in subsidiary		-	-	-	-
Acquisition of intangible assets		-	(3,007)	-	-
Advance against decommissioning cost	(2,292)	-	-	-	-
Net cash flows from financing activities	**(3,677)**	**(2,079)**	**(7,622)**	**(12,466)**	**(4,037)**
Financing Activities					
Proceeds from loans and borrowings	-	15,000	18,912	12,917	10,000
Repayment of loans and borrowings	(834)	(12,941)	(12,941)	(7,059)	(2,917)
Repayment of principal portion of lease liability	(89)	-	(131)	-	-
Repayment of interest portion of lease liability	(5)	-	(19)	-	-
Dividends paid to non-controlling interest	-	(5,150)	(9,062)	(5,665)	(2,125)
Dividends paid	-	-	-	(11,550)	-
Issue of share capital	10,945	-	-	1,182	-
Share issue costs	(542)	-	-	-	-
Net cash flows from financing activities	**9,475**	**(3,091)**	**(3,241)**	**(10,175)**	**4,958**
Net increase/(decrease) in cash and cash equivalents	**6,331**	**(16,779)**	**(13,778)**	**19,965**	**(143)**
Cash & cash equivalents at beginning of period	14,113	27,891	27,891	7,926	8,069
Cash & cash equivalents at end of period	**20,444**	**11,112**	**14,113**	**27,891**	**7,926**

10.3.4. Statement of changes in equity

USD '000s	***Issued Capital***	***Retained Earnings***	***Foreign Currency Translation Reserve***	***Non-controlling interests***	***Total***
Balance for the year ended 31 December 2020 (audited)	17,735	(8,853)	(956)	14.370	22,296
Profit for the period	-	3,029	-	5,836	8,865
Other comprehensive (loss)/ income	-	-	229	(258)	(29)
Total comprehensive (loss)/income for the period	-	3,029	229	5,578	8,836
Issue of share capital	10,945	-	-	-	10,945
Share issue costs	(542)	-	-	-	(542)
Acquisition of equity interest from NCI	-	-	-	(3,278)	(3,278)
Balance at 30 June 2021 (Unaudited)	**28,138**	**(5,824)**	**(727)**	**16,670**	**38,257**
Balance for the year ended 31 December 2019 (audited)	17,735	(11,226)	-	14,749	21,258
Profit for the period	-	(439)	-	3,370	2,931
Other comprehensive (loss)/ income	-	-	(316)	(186)	(502)
Total comprehensive (loss)/income for the period	-	(439)	(316)	3,184	2,429
Dividend paid	-	-	-	(5,150)	(5,150)
Balance at 30 June 2020 (Unaudited)	**17,735**	**(11,665)**	**(316)**	**12,783**	**18,537**
Balance at 31 December 2017	**120**	**5,850**	**-**	**5,713**	**11,683**
Increase in share capital of subsidiary	-	-	-	3	3
Total comprehensive Income for the year	-	7,838	-	9,220	17,058
Dividend paid	-	-	-	(2,125)	(2,125)
Balance at 31 December 2018	**120**	**13,688**	**-**	**12,811**	**26,619**
Total comprehensive Income for the year	-	(13,364)	-	7,603	(5,761)
Equity raise	17,615	-	-	-	17,615
Acquisition of a Subsidiary	-	-	-	-	-
Dividend paid	-	(11,550)	-	(5,665)	(17,215)
Balance at 31 December 2019	**17,735**	**(11,226)**	**-**	**14,749**	**21,258**
Profit for the year	-	2,373	-	8,777	11,150
Foreign currency exchange differences arising on translation from functional currency to presentation currency	-	-	(956)	(94)	(1,050)
Dividend paid	-	-	-	(9,062)	(9,062)
Balance at 31 December 2020	**17,735**	**(8,853)**	**(956)**	**14,370**	**22,296**

11. UNAUDITED PRO FORMA FINANCIAL INFORMATION

11.1. Introduction

During 2019 and 2020, the Group announced transactions to acquire licence interests for projects in Nigeria (completion is subject to governmental approval in Nigeria) and Guinea-Bissau (transaction completed in May 2021). If the last annual audited financial statements are used to assess the indicative impact the transactions have on the Group, both transactions would individually and combined cause a significant gross change for the Group.

The following unaudited pro forma financial information has been prepared using PetroNor Australia's consolidated financial statements and Financial Information. The implementation of the Scheme will be treated as a continuance of business under the Company (being the new listing entity). The financial statements for the Company going forward will be presented as a continuance of the activities of the Australian company PetroNor Australia.

11.2. Aje transaction

11.2.1. Transaction details

As announced on 21 October 2019, the Company entered into the Panoro Agreement for the acquisition of certain companies holding interests in OML-113 offshore Nigeria, containing the Aje Field. The Panoro Agreement contemplates the acquisition of 100% of the shares of PPSH and PPNH, which currently hold 100% of the shares in Pan-Petroleum Aje Limited, which participates in the exploration for and production of hydrocarbons in OML-113.

The consideration payable by the Group under the Panoro Agreement is (i) issue of shares in the Company for USD 10 million and (ii) a contingent payment obligation after PetroNor has recovered all costs related to the accumulated investments incurred after the Completion Date equal to USD 0.10 per 1,000 Cubic Feet of Aje Gas sales volume limited to USD 16.67 million.

In parallel, the Company concluded the YFP Agreement to create a SPV that will see such entity assume the lead technical and management role in the next phases of the Aje Field development. PetroNor and YFP will hold respectively 45% and 55% of the SPV shares, and the ability to appoint up to two directors each. The SPV will require two directors jointly to sign on its behalf, of which one is appointed by PetroNor and one appointed by YFP. The SPV will include the current license ownerships of YFP (the operator), YFP-DW and Panoro.

Together these agreements provide the framework and pathway towards sanctioning of the next phases of the Aje Field development in order to unlock its significant value through accessing the substantial proven gas and liquid in place reserves.

The completion of the Aje Transaction was subject to the satisfaction of certain conditions precedents, including the regulatory approval of the Nigerian Department of Petroleum Resources and consent of the Minister of Petroleum Resources.

The regulatory approval process in Nigeria, though delayed by the impact of the COVID-19 pandemic, is now finalized subject to the payment of USD 1 million to the Nigerian Government for the premium on assignment for OML-113 before 30 April 2022. The Aje Transaction is expected to be completed before 30 April 2022.

Upon the successful completion of the Aje Transaction, the Group will in the OML-113 licence acquire a nominal participating interest on 34 % and a revenue interest on 24.3%. These figures are based on the Group holding a 45% equity interest in the SPV, which in turn holds nominal licence interest on 75.5 % and a revenue licence interests on 54.1%. The table below shows all CAPEX, OPEX, and revenue for the SPV. PetroNor's interest is 45% relating to each figure.

The proportional allocation of operating expenditures and capital expenditures deviate from pro-rata allocation of revenues. Allocation of operating expenditures and capital expenditures are based on the following mechanic which were established in the Farm-In Agreements and Joint Operating Agreements in 2007.

SPV Aje Production	**Period 1:**	**Period 2:**	**Period 3:**
	Prior to YFP Payout	Post YFP Payout	Post Project Payout

Participation Interest	CAPEX and OPEX	Revenue (cost recovery and profit sharing)	CAPEX and OPEX	Revenue (cost recovery and profit sharing)	CAPEX	OPEX	Revenue (cost recovery and profit sharing)
75.50%	38.755%	54.066%	38.755%	38.755%	38.755%	54.066%	54.066%

As of the date of this Prospectus, the licence is in "Period 1" and the commencement of "Period 2" is subject to YFP receiving USD 30 million in net proceeds. This is the cost incurred by YFP in OML-113 prior to the first farming agreement in 2007. YFP has received USD 12 million and the recovery of an additional USD 18 million is required for commencement of "Period 2". Based on the expectations of the management of the Company, this is expected to be incurred in about 2 years. The commencement of "Period 3" is subject to the net proceeds less the prior costs exceeding the cumulative expenditure. Based on the expectations of the management of the Company, this is expected to take place in about 3 to 4 years.

11.2.2. Aje Transaction Accounting Treatment

The conditions precedent for completion of both the Panoro Agreement and YFP Agreement are interlinked; and accounting wise, the Company regard that the Aje Transaction should be considered as one event, and not the acquisition and immediate disposal of PPSH and PPNH.

The Company expects to classify its interest in the new special purpose vehicle Aje Production as a 'joint venture' under IFRS 11 and will account for the investment using the equity method, whereby the initial investment is recognized at cost and the carrying amount is increased or decreased recognizing the Company's share of profit or loss at each future period end.

Under the terms of the Panoro Agreement, the Company shall, either pay a cash consideration of USD 10 Million or issue consideration shares which in aggregate shall represent a total value of USD 10 Million to Panoro for the 100% equity share acquisition of PPSH and PPNH and their associated interest in OML-113, before the transfer of these PPSH and PPNH shares into Aje Production with YFP.

The Company anticipates to issue shares to conclude the Aje Transaction, thereby initially increasing non-current assets and equity by USD 10 million.

The Company will pay Panoro a conditional consideration of USD 0.10 per 1,000 cubic feet of the Aje Natural Gas Sales Volume (the "**Conditional Consideration**"). The Conditional Consideration will only be payable after Pan Aje has recovered all costs, both investments and operating costs, in relation to the gas production and the Conditional Consideration shall not exceed USD 16.67 million in cumulated payments.

11.2.3. Financial Information

The Aje Transaction involves the combination of six legal entities located in four different legal jurisdictions. Of which three entities have separate participating interests in the OML-113 lease in Nigeria and varying levels of economic interest.

Meaningful historical financial statements are not yet available for all entities involved in the Aje Transaction. Although the Company has received recent guidance and copy billing statements from the operator on the overall OML-113 operations. The separate entities that hold the participating interests may have additional corporate costs in addition to their respective license interest; and applying available financial numbers from one partner to pro rata estimate the figures for the total interest acquired may lead to incorrect information when combining financial information. Therefore, the Company is of the opinion that the only way to accurately reflect the Aje Transaction in this Prospectus is by providing narrative information. As such there is no report by independent accountants or auditors in relation to the Aje Transaction.

Due to the drop in oil price in 2020, the existing joint venture partners negotiated reduced lease rate for the FPSO currently in operation at the Aje Field. The rates agreed were heavily discounted on a sliding scale that was based on the actual selling price of oil. This has benefited the joint venture partners during the period of extreme low prices in 2020. The discount is now minimal with the recovery of the oil prices close to levels before the COVID pandemic. The contract for the FPSO was up for renegotiation during Q4 2021.

When the Aje Transaction completes, the Company will have to recognise its share of any losses incurred in the period since the locked box dates. Any losses to be recognised would reduce the carrying value of the initial investment in the SPV. Based on joint venture billing information for the period since the locked box dates, the Company estimates the carrying value of investments may be reduced by USD 3 – 5 million. However, the Company considers the underlying value of the investment to be realised through the planned re-development of the Aje Field, and not based on current production operations.

The average production in 2021 has dropped from 1,980 Bopd in 2020 to around 1,400 Bopd. This has resulted in drop of revenue and slowed any financial recovery to the joint venture account.

Until the overall completion of the Aje Transaction, the Company does not have influence over the operations of OML-113.

Legal and due diligence costs in connection with the Panoro Agreement and the YFP Agreement were expensed as arose in 2019. In 2020 and first six months of 2021, the company continued to use existing internal staffing to develop redevelopment plans for the Aje Field pending completion of the Aje Transaction, where these costs have been expensed as occurred.

Legal and travel costs incurred in 2019 and 2020 in relation to the Aje project are estimated at USD 300,000.

11.3. Guinea-Bissau transaction

On 20 November 2020, the Group announced the 100% share purchase of the entity SPE Guinea Bissau AB[20] (the "**GB Transaction**"), which subsequently completed on 4 May 2021. The GB Transaction allowed PetroNor to assume the Operatorship (and interest of 78.57%) of the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau.

The SEK 434,238 consideration paid in the transaction equaled the carrying amount of the net assets. In addition to the consideration paid, the Group paid USD 1.9 million in settlement of a payable balance to Svenska Petroleum Exploration AB on behalf of SPE Guinea Bissau AB.

The exploration licences held by SPE Guinea Bissau AB do not currently generate income, however a farm out of one or both of the licences may generate cash inflow from the reimbursement of past exploration costs.

11.3.1. Purpose of the unaudited pro forma financial information

The Company has prepared the pro forma statement of comprehensive income for the six month period ended 30 June 2021 and for the twelve-month period ended 31 December 2020 so as to illustrate how the GB Transaction would have affected the Company had it been completed at 1 January 2021 or at 1 January 2020 respectively, and this hypothetical compilation may differ from the Group's actual financial position or results.

Apart from the GB Transaction, no other circumstances occurring after 30 June 2021 are covered by the pro forma financial information. The sources of the historical financial information included in the pro forma financial statements are:

- For the Company, extracted from the PetroNor Australia audited consolidated financial statements as of 31 December 2020; and the PetroNor Australia unaudited consolidated interim financial statements as of 30 June 2021

- For SPE Guinea Bissau AB, extracted from the audited financial statements as of 31 December 2020 and derived from the unaudited management accounts and transactional history from 1 January 2021 to 30 April 2021.

As the GB transaction completed on the 4 May 2020, the PetroNor Australia unaudited consolidated interim financial statements as of 30 June 2021 already consolidates the results for SPE Guinea Bissau AB from 1 May 2021 to the 30 June 2021 into the consolidated financial statements. It is the results for SPE Guinea Bissau AB from 1 January 2021 to 30 April 2021 that must be adjusted to generate the pro forma information for the six-month period ended 30 June 2021.

Information on the source documents used to prepare the pro forma financial statements are included in Appendix G together with the signed pro forma financial information.

11.3.2. Accounting principles

The underlying source financial information for the Group included in the pro forma financial information is extracted from Financial Statements that have been prepared under Australian Accounting Standards and also complies with IFRS as issued by the International Accounting Standards Board.

SPE Guinea Bissau AB prepares its respective financial statements in SEK and under Swedish GAAP in accordance with the Annual Accounts Act and the BFN's (The Swedish Accounting Standards Board's) general advice BFNAR 2012: 1, This standard was developed by the BFN based on the IFRS for SMEs Standard but with amendments and exceptions due to Swedish Law and 'Swedish practice' as well to reflect Swedish tax law. The Company has identified differences between the

[20] As of 4 June 2021, SPE Guinea Bissau AB formally changed its name to PetroNor E&P AB.

Company's accounting policies and those applied by SPE Guinea Bissau AB that would impact the pro forma financial information, these are detailed in Section 11.3.3 below.

In accordance with IFRS 3, a purchase price allocation (PPA) has been performed in which the identifiable assets, liabilities and contingent liabilities of SPE Guinea Bissau AB have been identified. The PPA in the unaudited pro forma condensed financial information is based on the fair value of acquired assets and liabilities as of the date of acquisition. Assets acquired consist of inventory (Well heads), intangible assets (Licenses), trade receivables and cash. Liabilities assumed consist of trade payables.

The SEK 434,238 consideration paid in the transaction equaled the carrying amount of the net assets. Hence, the PPA did not identify any excess values that would give rise to any pro forma adjustments in the unaudited pro forma condensed financial information.

With regards to applicable exchange rates used in the pro forma statements:

- In the Statement of Comprehensive Income for the period to 31 December 2020 transactions recorded to the income have been translated at an average exchange rate of SEK 9.2106 to USD 1.00.

- In the Statement of Comprehensive Income for the period to 30 June 2021 transactions recorded to the income have been translated at an average exchange rate for each month ranging from SEK 8.2947to SEK 8.5427 to USD 1.00.

The pro forma financial information has not been audited in accordance with Norwegian or International Standards on Auditing ("**ISAs**"). However, BDO AS, Munkedamsveien 45, Postboks 1704 Vika, 0121 Oslo, has issued a report on the Pro Forma financial information included in Appendix F hereto. The report is prepared in accordance with ISAE 3420 "Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus". BDO AS is the auditor for the Company and was a component auditor for PetroNor Australia's independent auditor, BDO Audit (WA) Pty Ltd.

11.3.3. GB Transaction unaudited pro forma financial information

*Pro forma statement of comprehensive income for the year ended 31 December 2020**

USD '000s	**PetroNor E&P Ltd.**	**SPE Guinea Bissau AB**	**SPE Guinea Bissau AB translated**	**Accounting Policy adjustments**	***Notes***	**Pro Forma Adjustments**	***Notes***	**Pro Forma Consolidated**
	Audited	*Audited*	Unaudited	Unaudited		Unaudited		Unaudited
	USD	*SEK*	USD	USD		USD		USD
	$'000	*Kr'000s*	*$'000*	*$'000*		*$'000*		*$'000*
Revenue	67,543	-	-	-		-		67,543
Cost of Sales	(25,885)	-	-	-		-		(25,885)
Gross Profit	**41,658**	**-**	**-**	**-**		**-**		**41,658**
Other operating income	45	-	-	-				45
Impairment of intangible asset	-	*(319,431)*	(34,681)	-		34,433	*B1*	(248)
Administrative expenses	(12,376)	*(30,157)*	(3,274)	(508)	*A1*	-		(16,158)
Profit from operations	**29,327**	***(349,588)***	**(37,955)**	**(508)**		**34,433**		**25,297**
Finance Expenses	(2,606)	*(134)*	(15)	-		-		(2,621)
Finance income	-	*24*	3	-		-		3
Foreign exchange gain/loss	1,507	*1,899*	206	-		-		1,713
Group contribution received	-	*346,265*	37,594	(37,594)	*A2*	-		-
Profit/(loss) before tax	**28,228**	***(1,534)***	**(167)**	**(38,102)**		**34,433**		**24,392**
Tax Expense	(17,078)	-	-	-		-		(17,078)
Profit/ (loss) for the period	**11,150**	**(1,534)**	**(167)**	**(38,102)**		**34,433**		**7,314**
Other comprehensive income								
Exchange gains/(losses) arising on translation of foreign operations	(1,050)	-	(21)	(4,695)	*A2*	4,235	*B1*	(1,529)
Total comprehensive income/(loss)	**10,100**	***(1,534)***	**(188)**	**(42,797)**		**38,668**		**5,786**
Profit/Loss for the period attributable to:								
Equity holders of the parent	2,373	*(1,534)*	(167)	(38,102)		34,433		(1,463)
Non-controlling interests	8,777		-	-		-		8,777
	11,150	**(1,534)**	**(167)**	**(38,102)**		**33,925**		**7,314**
Total comprehensive income / (loss) attributable to:								
Equity holders of the parent	1,417	*(1,534)*	(188)	(42,797)		38,668		(2,897)
Non-controlling interests	8,683		-	-		-		8,683
	10,100	***(1,534)***	**(188)**	**(42,797)**		**38,668**		**5,786**

** The above table has been prepared on the basis that the acquisition transaction completed on 1 January 2020*

Note A1: Exploration expenses

SPE Guinea Bissau AB uses the 'successful efforts' method to account for exploration expenses, compared to the 'area of interest' method used by the Company. Consequently, SPE Guinea Bissau AB capitalizes exploration costs that would be expensed as incurred by the Group. The pro forma statements have been adjusted to reflect PetroNor Group accounting policies and costs capitalised in SPE Guinea Bissau AB during 2020 in the amount of SEK 4,678K have been expensed and reclassified according to PetroNor Group accounting policy. This is a one-off effect as SPE Guinea Bissau AB will adopt PetroNor Group accounting policies. Hence going forward exploration costs within SPE Guinea Bissau AB will be expensed in accordance with the "area of interest" method.

Note A2: Svenska Petroleum Exploration Aktiebolag shareholder contribution prior to acquisition

In 2020 SPE Guinea Bissau AB recognised a contribution from their parent entity Svenska Petroleum Exploration Aktiebolag in the amount of SEK 346,265,287. Under IFRS this contribution would have been accounted for as an equity contribution and not recognised as income. The GAAP adjustment in the comprehensive statement of income has been translated at the average exchange rate of SEK 9.2106 to USD 1.00. A GAAP adjustment has also been made for the related foreign currency translation difference. This is a one-off adjustment and not expected to have a continued impact.

Note B1: Exploration expenses

In the statement of comprehensive income for 2020 SPE Guinea Bissau AB recognized an impairment of fixed asset in the amount of SEK 319.4 million (USD 34.3 million) relating to the Sinapa Block 2 and Esperança Block 4a&5a. The fair value of these assets at the time of acquisition was SEK 1 and thus a pro-forma adjustment has been made to reflect that there would be no impairment loss in the consolidated financial statements for PetroNor in 2020 if the transaction was completed on January 1, 2020. A pro-forma adjustment has also been made for the related foreign currency translation difference. This is a one-off adjustment and not expected to have a continued impact.

*Pro forma statement of comprehensive income for the six month period ended 30 June 2021**

USD '000s	PetroNor E&P Ltd	SPE Guinea Bissau AB	SPE Guinea Bissau AB translated	Accounting Policy adjustments	*Notes*	Pro Forma Adjustments	*Notes*	Pro Forma Consolidated
	Six months ended 30 June 2021	Four months ended 30 April 2021	Four months ended 30 April 2021	Four months ended 30 April 2021		Four months ended 30 April 2021		Six months ended 30 June 2021
	Unaudited	*Unaudited*	Unaudited	Unaudited		Unaudited		Unaudited
	USD	*SEK*	USD	USD		USD		USD
	$'000	*Kr'000s*	*$'000*	*$'000*		*$'000*		*$'000*
Revenue	48,174	-	-	-		-		48,174
Cost of Sales	(16,832)	-	-	-		-		(16,832)
Gross Profit	**31,342**	**-**	**-**	**-**		**-**		**31,342**
Other operating income	-							-
Exploration expenses	(1,259)	-	-	-		-		(1,259)
Administrative expenses	(5,314)	*(1)*	-	(60)	*C1*	-		(5,374)
Profit from operations	**25,126**	***(1)***	**-**	**(60)**		**-**		**25,066**
Finance Expenses	(1,626)	*(37)*	(4)	-		-		(1,630)
Foreign exchange gain/loss	19	*(172)*	(29)	-		-		(10)
Profit/(loss) before tax	**23,519**	***(210)***	**(29)**	**(60)**		**-**		**23,426**
Tax Expense	(14,654)	-	-	-		-		(14,654)
Profit/ (loss) for the period	**8,865**	**(210)**	**(33)**	**(60)**		**-**		**8,772**
Other comprehensive income								
Exchange gains/(losses) arising on translation of foreign operations	(29)	-	-	-		-		(29)
Total comprehensive income/(loss)	**8,836**	***(210)***	**(33)**	**(60)**		**-**		**8,743**
Profit/Loss for the period attributable to:								
Equity holders of the parent	3,029	*(210)*	(33)	(60)		-		2,936
Non-controlling interests	5,836	-	-	-		-		5,836
	8,865	**(210)**	**(33)**	**(60)**		**-**		**8,772**
Total comprehensive income / (loss) attributable to:								
Equity holders of the parent	3,258	*(210)*	(33)	(60)		-		3,165
Non-controlling interests	5,578	-	-	-		-		5,578
	8,836	***(210)***	**(33)**	**(60)**		**-**		**8,743**

** The above table has been prepared on the basis that the acquisition transaction completed on 1 January 2021. The GB transaction actually completed on 4 May 2021,and the statement of comprehensive income for the six months ending 30 June 2021 for PetroNor E&P Ltd includes SPE Guinea Bissau AB from 1 May 2021. Therefore the results of SPE Guinea Bissau AB from 1 January 2021 to 30 April 2021 have been added to the consolidated financial statements to 30 June 2021 to generate the unaudited pro forma financial information.*

Note C1: Exploration expenses

SPE Guinea Bissau AB uses the 'successful efforts' method to account for exploration expenses, compared to the 'area of interest' method used by the Company. Consequently, SPE Guinea Bissau AB capitalizes exploration costs that would be expensed as incurred by the Group. The pro forma statements have been adjusted to reflect PetroNor Group accounting policies and costs capitalised in SPE Guinea Bissau AB during 2021 in the amount of SEK 513K have been expensed and reclassified according to PetroNor Group accounting policy. In accordance with Group policy these types of exploration costs will continue to be expensed. This is a one-off effect as SPE Guinea Bissau AB will adopt PetroNor Group accounting policies.

11.3.4. Independent assurance report on unaudited pro forma financial information

With respect to the unaudited pro forma financial information included in this Prospectus, BDO AS has applied assurance procedures in accordance with ISAE 3420 "Assurance Engagement to Report Compilation of Pro Forma Financial Information Included in a Prospectus" in order to express an opinion as to whether the unaudited pro forma financial information has been properly complied on the basis stated, and that such basis is consistent with the accounting policies of the Company. BDO AS has issued an independent assurance report on the unaudited pro forma financial information included as Appendix F to this Prospectus. There are no qualifications to this assurance report.

12. OPERATING AND FINANCIAL REVIEW

This operating and financial review should be read together with Section 4 "General Information", Section 8 "Business of the Group", Section 9 "Selected Financial and Other Information", Section 11 "Unaudited pro forma financial information" and the Financial Statements and the Interim Financial Statements, including related notes, included in Appendix B to E of this Prospectus. This operating and financial review contains forward-looking statements. These forward-looking statements are not historical facts, but are rather based on the Group's current expectations, estimates, assumptions and projections about the Group's industry, business, strategy and future financial results. Actual results could differ materially from the results contemplated by these forward-looking statements because of a number of factors, including those discussed in Section 2 "Risk Factors" and Section 4.3 "Cautionary note regarding forward-looking statements" of this Prospectus, as well as other sections of this Prospectus.

12.1. Presentation of financial information

Please refer to Section 4.2.1 "Historical financial information" for an overview of the Financial Information, being the audited PetroNor Norway Financial Statements for the 1 month period ending on 31 October 2021 for PetroNor E&P ASA (being the Company) and the consolidated Interim Financial Statements for the six month period ended 30 June 2021 and audited consolidated Financial Statements for the years ended 31 December 2020, 2019 and 2018 for PetroNor E&P Ltd. (being PetroNor Australia), the accounting standards pursuant to which such Financial Information have been prepared and the review that the Financial Information has been subject to.

As described above, the Interim Financial Statements and Financial Statements relates to PetroNor Australia, being the former ultimate parent company of the Group prior to the Redomiciliation, while the PetroNor Norway Financial Statements relates to the Company.

12.2. Factors affecting comparability of financial information

Reverse take-over transaction accounting in 2019

On 30 August 2019, the PetroNor Australia entered into a share purchase agreement with the Cypriot company PetroNor E&P Ltd. Consideration for 100% of the share capital of the Cypriot company comprised the following:

- 816,198,842 new shares issued at NOK 1.032 each;
- 155,466,446 warrants issued with a nil exercise price, vesting conditions and expiry date of 31 December 2019. The vesting conditions related to specific performance milestones including the signing of a binding gas offtake agreement for an asset in Nigeria; and
- USD 11,549,988 deferred cash consideration, payable and due upon the finalisation of the 2018 dividend from the operating subsidiary company HEPCO.

Costs associated with the transaction amounted to USD 2 million; and has been expensed as incurred by both sides. Therefore, only costs of USD 1.19M are included in the Statement of Comprehensive Income for the transaction, with the balance recognised as part of the retained losses of Australian PetroNor E&P Limited at the point of the merger.

The transaction has been considered a reverse takeover, but not a business combination. Although the Australian company PetroNor E&P Limited has licences in The Gambia and Senegal, with the ongoing arbitration matters there were no active operations, consequently the Company was considered a 'non-business' listed company.

The Cypriot company PetroNor E&P Ltd is considered the accounting acquirer and the Australian company PetroNor E&P Limited is the legal acquirer.

The acquisition is accounted for as a continuation of the financial statements of the Cypriot PetroNor E&P Ltd. The Transaction assessed fair value in excess of the net assets of Australian PetroNor E&P Limited, and an estimate for listing expenses has been expensed as a share-based payment in accordance with AASB 2.

Application of IFRS 16

The Group applied IFRS 16 since 1 January 2020. IFRS 16 introduced significant changes to lessee accounting by removing the distinction between operating and finance leases and requiring the recognition of a right-of-use asset and a lease liability at commencement for all leases, except for short-term leases and leases of low value assets.

For further information on the implementation of IFRS 16, please see note 7 "Lease agreements" in the Group's audited consolidated financial statements for the year ended 2020. The impact of this change was not material to the Group.

12.3. Overview and general background

As at the date of this Prospectus and as reported in the Financial Statements and the Interim Financial Statements, the Company only report one segment as all revenue is reported within one geographic area.

12.4. Key factors affecting the Group's results of operation and financial performance

The business, financial condition, results of operations and cash flows, as well as the period-to-period comparability of the financial results of the Group, are affected by a number of factors. Some of the factors that have influenced the Group’s financial condition and results of operations during the periods under review and which are expected to continue to influence the Group’s business, financial condition, results of results of operations and cash flows, as well as the period-to-period comparability of the Group's financial results, are:

Oil and Gas Prices

Oil prices are fluctuating over time and had a severe drop in 2020. However, since then, oil prices have recovered substantially. As evidenced by the price changes in recent years, the oil price is highly dependent on the current and expected future supply and demand of oil. Changes in prices on the Group's products may lead to a material change in net production revenues. Further, changes in oil and gas prices could result in substantial adjustments of oil and gas reserves. If this occurs, the Group may be required to adjust the carrying value of its proved oil and gas properties. Less reserves will lead to higher depreciation in the Group's income statement, all other things equal. Further, planned CAPEX spending may not be sustainable based on lower prices.

Developments in the global offshore oil and gas market

The Group's income is completely based on the sale of oil and gas. Thus, changes in oil and gas prices and fluctuations in investments in offshore developments and exploration results, will materially affect the Group's business, financial condition, results of operations and prospects. For instance, low oil prices may lead to a reduction in exploration as the Company may have to scale down its investment budgets, which could directly affect the results of the Group's operations and future prospects.

Limited number of revenue streams

Only one of the Group's hydrocarbon fields is currently in production, and it will take years before the next field is expected to draw first oil. This leaves the Group with a limited number of revenue streams. The limited number of revenue streams may materially affect the Group's ability to explore and develop further fields, which would have a material effect on the Group's business, prospects, financial condition and results of operation. Changes in the revenue stream from this production location could affect the Group's prospects, financial condition and results of operation to a greater extent than it would for a company with several active production fields.

Reserves and contingent resources

The Group cannot measure the volumes in the reservoir directly. It will always have to rely on data from wellbore(s) or seismic surveys. Models to evaluate volumes of reserves and resources are in itself highly complex and the Group cannot guarantee that these models are correct. Actual production, revenues and expenditures with respect to reserves and resources may vary from estimates, and the variances may be material. If the assumptions upon which the estimates of the Group's oil and gas reserves or resources are proved to be incorrect, the Group may be unable to recover and/or produce the estimated levels or quality of oil or gas (and vice versa). Changes in reserves affect the Group's business, prospects, financial condition and results of operations.

Investments

Developing a field into production requires significant investments and implementation of technology over several years. Making these investments and implementing these technologies, usually under difficult conditions, can result in uncertainties about the amount of investment necessary, operating costs and additional expenses incurred as compared to the initial budget. Moreover, investments may be made on fields that turn out to not be commercially viable. The Company may incur higher or lower costs than budgeted. In addition, the Company may need to impair previously capitalized expenses for exploration wells on non-commercial fields.

Operating and Drilling Costs

Changes in the cost of field exploration, production and development would affect the Company's ability to invest in prospects and to purchase or hire equipment, supplies and services. Changes in the Company's ability to invest would negatively affect the Company's production and revenue. Current or future projected target dates for production may be delayed and cost overruns may occur. Such factors may impact the extent to which the fields to be developed are fully funded or remain commercially viable and consequently may impact the Company's cash flows.

Environmental, social and governance regulations

The Company is subject to environmental, social and governance regulation pursuant to a variety of international conventions and national regulations as well as applicable health and safety regulations. Compliance with the legislation may require significant expenditures and breaches may result in the imposition of fines and penalties in addition to loss of reputation. The Company may be subject to large fines if relevant regulations are breached, increasing costs and reducing profit. Further changes in current regulation may impact the Company as compliance costs may increase, reducing profit.

Other material factors

Other factors that are currently known to the Group and which may or have influenced the Group and are expected to continue to influence the Group's future results include, but are not limited to:

- changes in global economic conditions;
- restrictions on cash flows from the Company's subsidiaries;
- operational problems;
- uncertainty in estimation of reserves;
- civil, economic, political and military unrest in the areas in which the Group operates;
- the degree to which counterparties or partners meet their obligations;
- the degree to which the Group is able to attract and retain key management personnel and other employees;
- the implementation the Group's business strategy or growth management;
- political, governmental, social, legal and regulatory changes;
- adequacy of the Group's insurance to cover the Group's losses;
- litigation or other disputes;
- the Group's financing;
- availability of required additional capital;
- significant exchange or interest rate fluctuations; and

12.5. Segments

The Group's revenue from operations is derived entirely from oil and gas production in Congo, amounting to USD 48.2 million for the period ended 30 June 2021 and USD 30.3 million for the same period 2020. The revenue for the years ended 31 December 2020, 2019 and 2018 was USD 67.54 million, USD 102.76 million and USD 101,069 million.

Therefore, the revenue from Congo exceeds the 75% threshold within IFRS 8 - Operating Segments and all operations are considered one segment. Apart from the geographic location of non-current assets, no further segmental reporting is disclosed in the financial statements of PetroNor Australia.

12.6. Description of key line items

Revenues

The Group's revenue is derived from the sale of petroleum products. All revenue from the sale of petroleum products is generated from a single customer and recognized and transferred at a point in time, being the point at which the customer obtains control, normally this is when title passes at point of delivery. Revenues from the sale of petroleum products are recognised based on actual volumes lifted and sold to customers during the period.

Cost of sales

Cost of sales is made up of operating expenses, royalties, depreciation and amortization of oil and gas properties and closing oil inventories. Inventories are valued at the lower of cost or net realizable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses.

Salary and other personnel expenses

Salary and other personnel expenses include all elements of direct costs of employees including provision of employee benefits.

Other operating expenses

Other operating expenses include all other expenditures not defined elsewhere including costs such as legal and consulting, travel, corporate and social responsibility etc.

Depreciation, amortization and impairment

Depreciation, amortization and impairment costs include the cost of the depletion of oil and gas assets, other asset depreciation and the amortization of leasehold assets. Impairment of assets would also be recognized within this classification. Oil and gas properties are depleted using the unit-of-production method, as 1P proved reserves are produced the costs of the asset is amortised over production. Property plant and equipment not associated with exploration and production activities are depreciated over the life of the assets. Right of Use leasehold assets are amortised over the life of the lease.

Financial income and expenses

Financial income and expenses include interest costs and loan structuring fees, finance costs on leasehold liabilities, the cost of the unwinding of the discount on decommissioning liabilities, foreign exchange income and expenditure.

Income tax expenses

The income tax expense is only related to the subsidiary in Congo and represents the assignment of tax oil on the revenue from sales of petroleum products. There is no income tax expense in the other subsidiaries jurisdictions nor in the parent's jurisdiction as these companies are in a taxable loss position.

12.7. The Group's results of operations

12.7.1. Results of operations for the 6 months' period ended 30 June 2021 compared to the six-months' period ended 30 June 2020

The table below sets forth selected comparative results of operations from the Group's Interim Financial Statements:

Amounts In USD '000's	**Six months ended 30 June**	
	2021	**2020**
Revenues	48,174	30,263
Cost of sales	(14,517)	(10,738)

Amounts In USD '000's	Six months ended 30 June	
	2021	**2020**
Salaries and personnel expenses	(2,464)	(3,310)
Other Income	357	5
Exploration Expense	(1,259)	-
Other operating expenses	(2,747)	(2,625)
Depreciation and amortization	(2,418)	(1,947)
Operation profit (loss)	25,126	11,648
Net financial items	(1,607)	(634)
Profit (loss) before tax	23,519	11,014
Income tax expense	(14,654)	(8,083)
Net profit (loss)	8,865	2,931

Revenues increased by USD 18 million, or 59%, to USD 48.2 million for the six months ended 30 June 2021 as compared to USD 30.3 million for the six months ended 30 June 2020. The main reason for the increase in this revenue was the increase in average selling price, which increased to USD 62.95/bbl in H1 2021 while it was USD 37.35/bbl in H1 2020.

Cost of sales

Cost of sales increased by USD 3.7 million, or 35%, to USD 14.5 million for the six months ended 30 June 2021 as compared to USD 10.7 million for the six months ended 30 June 2020. The increase in cost of sales corresponds to the increase in revenue because of the increase in royalty resulting from a higher selling price.

Exploration expenses

Exploration expenses in H1 2021 related to data acquired as part of the acquisition of the Guinea-Bissau assets, there was no equivalent activity in 2020.

Salaries and personnel expenses

Salary and personnel expenses decreased by USD 0.8 million, or 26%, to USD 2.5 million for the six months ended 30 June 2021 as compared to USD 3.3 million for the six months ended 30 June 2020. The decrease is mainly because there were termination benefits expensed in H1 2020, the terminations were the result of post-merger changes in the management team.

Other operating expenses

Other operating expenses increased by USD 0.1 million, to USD 2.7 million for the six months ended 30 June 2021 as compared to USD 2.6 million for the six months ended 30 June 2020.

Depreciation and amortization

Depreciation and amortization increased by USD 0.5 million, or 24%, to USD 2.4 million for the six months ended 30 June 2021 as compared to USD 1.9 million for the six months ended 30 June 2020. The increase in depreciation corresponds to the increase in cost of the non-current assets from USD 30.9 million as of 30 June 2020 to USD 34.6 million as of 30 June 2021.

Operating profit

Operating profit increased by USD 13.5 million, to USD 25.1 million for the six months ended 30 June 2021 as compared to USD 11 million for the six months ended 30 June 2020. The increase is driven by the increase in revenue.

Net financial items

Net financial items increased by USD 1.0 million, to USD 1.6 million for the six months ended 30 June 2021 as compared to USD 0.6 million for the six months ended 30 June 2020. This increase is because of higher interest paid on the Rasmala Loan. The interest rate on this loan is directly linked to the oil price, the oil price was higher during H1 2021 and thus the Group paid higher interest on the loan.

Net profit (loss)

Net profit increased by USD 5.9 million, to USD 8.8 million for the six months ended 30 June 2021 as compared to USD 2.9 million for the six months ended 30 June 2020.

12.7.2. Results of operations for the year ended 31 December 2020 compared to the year ended 31 December 2019

The table below sets forth selected comparative results of operations from the Group's annual Financial Statements for the years ended 31 December 2020 and 2019:

Amounts In USD '000's	**2020**	**2019**
Revenues	67,543	102,760
Cost of sales	(21,456)	(33,976)
Salaries and personnel expenses	(5,902)	(4,035)
Other operating expenses	(6,259)	(15,758)
Other Income	45	9
Depreciation and amortization	(4,644)	(3,231)
Operation profit (loss)	29,327	45,769
Share of net profit in jointly-controlled activities	-	-
Net financial items	(1,099)	(21,636)
Profit (loss) before tax	28,228	24,133
Income tax expense	(17,078)	(29,894)
Net profit (loss	11,150	(5,761)

Revenues

The Group's revenues decreased by USD 35 million, or 34%, to USD 67.5 million for the year ended 31 December 2020 as compared to USD 102.8 million for the year ended 31 December 2019.

The quantity of oil lifted for the year ended 31 December 2020 was 993,574 bbls which was 112,730 bbls more than the year ended 31 December 2020. The reduction in revenue was driven by the reduction in the average selling price per barrel USD 40.9/bbl for the year ended 31 December 2020 a decrease of USD 24.35/bbl from the year ended 31 December 2019 USD 65.25/bbl the market price reduction in the price of oil was caused by the COVID-19 pandemic.

Cost of sales

The Group's cost of sales decreased by USD 12.4 million, or 37%, to USD 21.5 million for the year ended 31 December 2020 from USD 33.9 million for the year ended 31 December 2019. The decrease directly corresponds to the decrease in revenues and hence reduction in royalties, other operating expenses were also reduced as a result of the reduction in activity caused by the COVID-19 pandemic.

Salary and other personnel expenses

Salary and other personnel expenses increased by USD 1.9 million, or 46%, to USD 5.9 million for the year ended 31 December 2020 as compared to USD 4.0 million for the year ended 31 December 2019. The increase was mainly due to changes in the corporate structure following the merger between African Petroleum and PetroNor. The increase was largely driven by termination costs of USD 0.8million for the year ended 31 December 2020 versus Nil for the year ended 31 December 2019.

Other operating expenses

Other operating expenses decreased by USD 9.5 million, or 60%, to USD 6.3 million for the year ended 31 December 2020 as compared to USD 15.8 million for the year ended 31 December 2019. The change was primarily due to the write off of related party expenditure of USD 6.0 million in the year ended 31 December 2019. Legal and professional fees reduced by USD 2.7 million or 46% to USD 3.1 million for the year ended 31 December 2020 from USD 5.8 million for the year ended 31December 2019 The decrease of USD 0.8 million in travel expenditure between 2019 and 2020 was a result of the COVID-19 pandemic.

Depreciation, amortization and impairment

Depreciation, amortization and impairment was increased by USD 1.4 million to USD 4.6 million for the year ended 31 December 2021 from USD 3.2 million reflecting increased production as assets are depleted on a unit of production basis depletion rates will be higher when production increases.

Operating profit / loss

Operating profit decreased USD 16.4 million 36%, to USD 29.3 million for the year ended 31 December 2020 from USD 45.8 million for the year ended 31 December 2019. The decrease was due to the factors described above.

Net financial items

Net financial items decreased by USD 20.5 million, or 95%, this was largely due to the share-based payment charge of USD 19.4 million in the year ended 31 December 2019 which led to a net expense of USD 21.6 for the year ended 31 December 2019 reducing to USD 1.1 million for the year ended 31 December 2020. The impact of the share-based payment charge is explained in the Section 11.2.

Profit/loss before tax

The Group's profit before tax increased by USD 4.1 million, or 17%, to USD 28.2 million for the year ended 31 December 2020 as compared to USD 24.1 million for the year ended 31 December 2019.

Income tax expense

Tax expense decreased USD 12.8 million, or 43%, to USD 17.1 million for the year ended 31 December 2020 as compared to USD 29.9 million for the year ended 31 December 2019. The tax charges are an assignment of tax oil on revenue from sales of petroleum products. This decrease was driven by pricing factors affecting oil revenue in 2020.

Net profit / loss

The Group reported net profit of USD 11.1 million for the year ended 31 December 2020 as compared to a net loss of USD 5.8 million for the year ended 31 December 2019.

12.7.3. Results of operations for the year ended 31 December 2019 compared to the year ended 31 December 2018

The table below sets forth selected comparative results of operations from the Group's annual Financial Statements for the years ended 31 December 2019 and 2018:

Amounts In USD'000's	**2019**	**2018**
Revenues	102,760	101,069
Cost of sales	(33,976)	(38,371)
Salaries and personnel expenses	(4,035)	(4,206)
Other operating expenses	(15,758)	(10,691)
Other income	9	491
Depreciation and amortization	(3,231)	(3,206)
Operation profit (loss)	45,769	49,893
Share of net profit in jointly-controlled activities	-	-
Net financial items	(21,636)	(1,711)
Profit (loss) before tax	24,133	48,182
Income tax expense	(29,894)	(31,124)
Net profit (loss)	(5,761)	17,058

Revenues

The Group's revenues increased by USD 1.7 million, or 2%, to USD 102.8 million for the year ended 31 December 2019 as compared to USD 101.1 million for the year ended 31 December 2018.

The quantity of oil lifted for the year ended 31 December 2019 was 880,884 bbls. This was slightly more than the quantity lifted for the year ended 31 December 2018 (812,000 bbls) The average selling price of USD 65.25 / bbl for the year ended 31 December 2019 was slightly less than the average selling price for the year ended 31 December 2018, USD 67.35 / bbl. The increase in volumes however led to the increase in revenue.

Cost of sales

The Group's cost of sales increased by USD 0.4 million, or 1%, to USD 34 million for the year ended 31 December 2019 from USD 33.6 million for the year ended 31 December 2018. The slight increase in operating costs is in line with the activity associated with the increase in revenue.

Salary and personnel expenses

Salary and personnel expenses decreased by USD 0.2million, or 4%, to USD 4.0 million for the year ended 31 December 2019 as compared to USD 4.2 million for the year ended 31 December 2018.

Other operating expenses

Other operating expenses increased by USD 9.9 million, to USD 15.8 million for the year ended 31 December 2019 as compared to USD 10.7 million for the year ended 31 December 2018. The increase is mainly because of a related party write off of USD 6 million and increases in legal and professional expenses arising in connection to the merger of APCL and PetroNor.

Depreciation, amortization and impairment

Depreciation, amortization and impairment was flat year on year USD 3.2 million for the year ended 31 December 2019 and USD 3.2 million for the year ended 31 December 2018.

Operating profit / loss

The Group's operating profit decreased by USD 4.1 million, or 8%, to an operating profit of USD 45.8 million for the year ended 31 December 2019 from an operating profit of USD 49.9 million for the year ended 31 December 2018. The decrease was primarily related to the factors explained above.

Net financial items

Net financial costs increased by USD 19.9 million, to USD 21.6 million for the year ended 31 December 2019 from USD 1.7million for the year ended 31 December 2018. The increase was driven by a share-based payment charge of USD 19.4 million in 2019 relating to the reverse takeover involving APCL as further described in Section 8.5 "History of the Group". Please refer to the beginning of this Section for more details on the Share Based Payment charge.

Profit/loss before tax

The Group's profit before tax USD 24.1 million, was reduced by 50%, for the year ended 31 December 2019 from USD 48.1 million for the year ended 31 December 2018 as a result of the factors described above.

Income tax expense

The Group's tax expense was reduced by USD 1.2 million, or 4%, to USD 29.9 million for the year ended 31 December 2019 from USD 31.1 million for the year ended 31 December 2018. The tax cost relates to the assignment of tax oil on revenue from sales of petroleum products

Net profit / loss

The Group's earnings switched to a loss of USD 5.8 million for the year ended 31 December 2019 from a profit of USD 17.0 million for the year ended 31 December 2018, the largest factor in this change being the share-based payment charge.

12.8. Alternative Performance Measures

The tables below set out certain APMs presented by the Group in this Prospectus on an historical interim and annual basis. The tables below show the relevant APMs on a reconciled basis, to provide investors with an overview of the basis of calculation of such APMs. See Section 4.2.5 "Alternative performance measures (APMs)" above for a further description of the APMs presented below.

The table below presents the items excluded from EBITDA and a reconciliation of EBITDA to Operating profit as presented in the Groups Financial Statements and Interim Financial Statements:

	Six months ended 30 June		**Year ended 31 December**		
USD millions	**2021**	**2020**	**2020**	**2019**	**2018**
Operating profit	25.1	11.6	29.3	45.8	49.9
Depreciation, amortization and impairment	2.4	2.0	4.6	3.2	3.2
*Estimated IFRS 16 Effect**	-	-	-	-	-
EBITDA	27.5	13.6	33.9	49.0	53.1
*Special items (recognized additional Covid-19 expenses)***					

*The company implemented IFRS 16 1 January 2019, using the cumulative catch-up approach which does not permit restatement of comparatives. The IFRS 16 effect on the year ended 31 December 2018 EBITDA is based on management best estimate assuming IFRS 16 was in place during that period. For further information, see section 11.2 "Factors affecting comparability of financial information" in this Prospectus.

** See section 4.2.5 "Alternative Performance Measures" for further details.

The table below provides a calculation of Net Interest Bearing Debt:

	Six months ended 30 June		**Year ended 31 December**		
USD millions	**2021**	**2020**	**2020**	**2019**	**2018**
Non-current interest-bearing liabilities	10.1	15.0	14.9	-	2.1
Current interest-bearing liabilities	8.0	-	4.0	12.9	5.0
Long and short term lease liability*	0.1	0.1	0.1	-	-
Cash and cash equivalents	(20.4)	(11.1)	(14.1)	(27.9)	(7.9)
Net-interest bearing debt	**(2.2)**	**4.0**	**5.2**	**(15.0)**	**(0.8)**

*2018 amount represents lease liability 1 January 2019 following the implementation of IFRS 16.

EBITDA changed by USD 13.9 million to USD 27.5 million for the six months ended 30 June 2021, from USD 13.6 million for the six months ended 30 June 2020. Changes were primarily a result of changes in revenue caused by the fluctuating oil price triggered by the COVID pandemic.

EBITDA changed by USD 15.1 million to USD 33.9 million for the year ended 31 December 2020, from USD 49.0 million for the year ended 31 December 2019. Changes were primarily a result of changes in revenue caused by the fluctuating oil price triggered by the COVID pandemic.

EBITDA changed by USD 4.1 million to USD 49.0 million for the year ended 31 December 2019, from USD 53.1 million for the year ended 31 December 2018. Changes mainly relates to higher operating costs in 2018.

12.9. Statement of financial position

12.9.1. Financial position as of 30 June 2021 compared to 31 December 2020

The table below sets forth selected comparative figures from the statement of financial position derived from the Group's Financial Statements, including the Interim Financial Statements for the 6 month period ended 30 June 2021:

Amounts in USD'000s	30 June 2021	31 December 2020
Assets		
Total non-current assets	53,161	51,890
Total current assets	34,674	27,088
Total assets	87,835	78,978
Equity and liabilities		
Equity		
Total equity	38,257	22,296
Total non-current liabilities	25,883	30,274
Total current liabilities	23,695	26,408
Total liabilities	49,578	56,682
Total equity and liabilities	87,835	78,978

Total non-current assets

At 30 June 2021, the Group's non-current assets were USD 53.2 million, an increase of USD 1.3 million, or 2.45%, as compared to USD 51.9 million at 31 December 2020. The increase is because of the CAPEX incurred during the period on the assets in Congo (USD 1.4 million) and the advance paid towards the decommissioning cost (USD 2.3 million). The depreciation and amortization charge for the period was USD 2.4 million.

Total current assets

At 30 June 2021, the Group's current assets were USD 34.7 million, an increase of USD 7.6 million, or 28%, as compared to USD 27.1 million at 31 December 2020. The increase represents an increase of USD 1.2 million in the inventory and USD 6.2 million increase in the cash and cash equivalents. The increase in inventory is mainly because of increase in supplies and materials inventory in the HEPCO.

Total assets

At 30 June 2021, the Group's total assets were USD 87.8 million, an increase of USD 8.8 million, or 11.2%, as compared to USD 79.0 million at 31 December 2020.

Total equity

At 30 June 2021, the Group's total equity were USD 38.3 million, an increase of USD 16 million, or 72%, from USD 22.3 million at 31 December 2020. The increase is mainly because of the share capital issued in a private placement of shares.

Total non-current liabilities

At 30 June 2021, the Group's non-current liabilities were USD 25.9 million, a decrease of USD 4.4 million, or 14.5%, from USD 30.3 million at 31 December 2020. The decrease is mainly because of the repayment of Rasmala Loan and transfer of some portion of loan from non-current to current liabilities.

Total current liabilities

At 30 June 2021, the Group's current liabilities were USD 23.7 million, a decrease of USD 2.7 million, or 10%, from USD 26.4 million at 31 December 2020. The change is mainly due to a reduction in a related party balance which was reclassified to increase in shareholding in HEPCO following a court order. The said transaction is explained in detail in Section 2.2.6.

Total equity and liabilities

At 30 June 2021, the Group's equity and liabilities totalled USD 87.8 million, an increase of USD 8.8 million, or 11%, from USD 78.9 million at 31 December 2020.

12.9.2. Financial position as of 31 December 2020 compared to 31 December 2019

The table below sets forth selected comparative figures from the statement of financial position derived from the Group's annual Financial Statements

Amounts in USD'000s	**2020**	**2019**
Assets		
Total non-current assets………………………………………………………	51,890	27,278
Total current assets……………………………………………………………..	27,088	55,896
Total assets………………………………………………………………………………	78,978	83,174
Equity and liabilities		
Equity		
Total equity…………………………………………………………………………..	22,296	21,258
Total non-current liabilities…………………………………………………	30,274	14,373
Total current liabilities……………………………………………………………	26,408	47,543
Total liabilities..…………………………………………………………………….	56,682	61,916
Total equity and liabilities………………………………………………………	78,978	83,174

Total non-current assets

As of 31 December 2020, the Groups total non-current assets were USD 51.9 million, a USD 24.6 million increase, or 90%, compared to USD 27.3 million as of 31 December 2019. The change was primarily driven by reclassification of an advance against decommissioning costs (USD 21.3 million) from current assets to non-current assets.

Total current assets

As of 31 December 2020, the Groups' total current assets were USD 27.1 million, a decrease of USD 28.8 million, or 51.5%, compared to USD 55.9 million as of 31 December 2019. The change was primarily driven by the reclassification of an advance against decommissioning cost (USD 21.3 million) from current assets to non-current assets. As of 31 December 2020, 100% of the Group's receivables were either not due or less than 30 days past due (compared to 100% as of 31 December 2019).

Total assets

As of 31 December 2020, the Groups total assets were USD 79.0 million, a of USD 4.2 million decrease, or 5%, compared to USD 83.2 million as of 31 December 2019. This decrease was mainly related to the reduction in cash balances of USD 13.8 million.

Total equity

As of 31 December 2020, the Groups total equity was USD 22.3 million, an increase of USD 1.0 million, or 4.9 %, compared to USD 21.3 million as of 31 December 2019. The increase was mainly due to the movement in retained earnings.

Total non-current liabilities

As of 31 December 2020, the Group's total non-current liabilities were USD 30.3 million, an increase of USD 15.9 million, compared to USD 14.4 million as of 31 December 2019. The balance increased because of the long-term loan facility taken out during the year 2020.

Total current liabilities

As of 31 December 2020, the Group's total current liabilities were USD 26.4 million, a decrease of USD 21.1 million, or 44.5%, compared to USD 47.5 million as of 31 December 2020. The change was primarily driven by a decrease in current debt of USD 8.9 million and a decrease in Trade and other payables of USD 12.2 million versus the high 2019 closing position which were largely working capital movements in HEPCO

Total equity and liabilities

As of 31 December 2020, the Groups total equity and liabilities were USD 79 million, a decrease of USD 4.2 million, or 5%, compared to USD 83.2 million as of 31 December 2019. The main drivers for the change are discussed above.

12.9.3. Financial position as of 31 December 2019 compared to 31 December 2018

The table below sets forth selected comparative figures from the statement of financial position derived from the Group's Annual Financial Statements.

Amounts in USD'000s	**2019**	**2018**
Assets		
Total non-current assets	27,278	18,145
Total current assets	55,896	38,706
Total assets	83,174	56,851
Equity and liabilities		
Equity		
Total equity	21,258	26,619
Total non-current liabilities	14,373	15,579
Total current liabilities	47,543	14,653
Total liabilities	61,916	30,232
Total equity and liabilities	83,174	56,851

Total non-current assets

Total non-current assets as of 31 December 2019 were USD 27.3 million, which represented an increase of USD 9.1 million, or 50%, compared to USD 18.1 million as of 31 December 2018. The main changes are related to a net increase in producing assets in the PNGF South field where gross capex (before depletion and amortization) increased by USD 12.5 million.

Total current assets

Total current assets were USD 55.9 as of 31 December 2019, representing an increase of USD 17.2 million, or 44%, compared to USD 38.7 million as of 31 December 2018. The change was primarily driven by a USD 20.0 million increase in cash and cash equivalents.

Total assets

Total assets were USD 83.2 million as of 31 December 2019, representing an increase of USD 26.3 million, or 46%, compared to USD 56.9 million as of 31 December 2018. The main drivers for the change are related to the details above.

Total equity

Total equity was USD 21.3 million as of 31 December 2019, which represents a decrease of USD 5.4 million, or 20%, compared to USD 26.6 as of 31 December 2018.

Total non-current liabilities

Total non-current liabilities were USD 14.4 million as of 31 December 2019, representing a decrease of USD 1.2 million, compared to USD 15.6 million as of 31 December 2018.

Total current liabilities

Total current liabilities were USD 47.5 as of 31 December 2019, representing an increase of USD 32.9 million, or 224%, compared to USD 14.7 million as of 31 December 2018. The change was primarily driven by increased loan liabilities of USD 5.0 million and an increase in Trade and other payables of USD 24.9 million.

Total equity and liabilities

As of 31 December 2019, the Groups total equity and liabilities were USD 83.2 million, an increaser of USD 26.3 million or 46%, compared to USD 56.9 million as of 31 December 2018. The drivers for the change are discussed above.

12.10. Liquidity and capital resources

12.10.1. Sources of liquidity and use of cash

The Group's principal sources of liquidity are cash flow from operations and equity injected by its shareholders and supplemented with debt financing from Rasmala and Symero (as further described below in Section 12.9.5 "Financing arrangements"). The Company itself is a non-operative holding company, and the main portion of the Group's cash balance is therefore held at subsidiary level to cover the daily liquidity requirements of the operating subsidiaries.

The Group's liquidity requirements arise primarily from the requirement to fund operating expenses, working capital, capital expenditures, and servicing of debt.

The table below shows the Group's net interest-bearing debt as at 30 June 2021.

Amounts in USD 000's	**As at 30 June 2021**
Non-current interest-bearing financial liabilities	(10,078)
Current interest-bearing liabilities	(8,000)
Lease liability	(142)
Less:	
Cash and cash equivalents	20,444
Totalt net interest-bearing debt	**(2,224)**

The Group's ability to generate cash from operations depends on its future operating performance, which is in turn dependent on general macroeconomic, financial, competitive and market regulatory conditions, many of which are beyond the Group's control, as well as other factors described in Section 12.4 "Key factors affecting the Group's results of operations and financial performance" above.

The Group intends to use free cash generated from operations primarily to support investments needed in order to support its growth strategy, to service debt and pay dividends.

The Company does not have any restrictions that can have a material impact on the use of its capital.

12.10.2. Cash flow for the six months ended 30 June 2021 compared to the six months ended 30 June 2020

	Six months ended 30 June	
Amounts in USD 000's	**2021**	**2020**
Net cash flows from operating activities..	533	(11,609)
Net cash flows from investing activities..	(3,677)	(2,079)
Net cash flows from financing activities...	9,475	(3,091)

Cash and cash equivalents at end of period..	20,444	11,112

Cash flow from operating activities

Cash inflow from operating activities was USD 0.5 million for the six months ended 30 June 2021, an increase of USD 12.1 million, from USD (11.6) million for the six months ended 30 June 2020. The increase in operating cash flow is linked to the increase of USD 6.4 million in net profit of the Group and secondly the reclassification of the amounts paid towards "advance against decommissioning cost" to investing activities.

Cash flow from investing activities

Cash outflow from investing activities was USD (3.7) million for the six months ended 30 June 2021, an increase of USD (1.6) million, or 77%, from USD (2.1) million for the six months ended 30 June 2020. The increase in the net cash used in investing activities is mainly because of the reclassification of advance against decommissioning cost from operating to investing activities.

Cash flow from financing activities

Cash inflow from financing activities was USD 9.5 million for the six months ended 30 June 2021, an increase of USD 12.6 million, from USD (3.1) million for the six months ended 30 June 2020. H1 2021 saw the receipt of USD10.4million from an equity raise, whilst in the first half of 2020 the financing restructure netted USD$3.0 million which was offset by a dividend payment of USD 5.1 million.

12.10.3. Cash flow for the year ended 31 December 2020 compared to the year ended 31 December 2019

Amounts in USD 000's	**2020**	**2019**
Net cash flows from operating activities...	(2,915)	42,606
Net cash flows from investing activities...	(7,622)	(12,466)
Net cash flows from financing activities...	(3,241)	(10,175)
Cash and cash equivalents at end 31 December......................................	14,113	27,891

Cash flow from operating activities

Cash inflow from operating activities was USD (2.9) million for the year ended 31 December 2020, a decrease of USD (45.5) million, from USD 42.6 million, a decrease of 107% for the year ended 31 December 2019. The decrease in cash flow was driven by decrease in trade payables of USD (12.4) million in 2020 versus an increase in trade payables of USD 25.0 million in 2019. Over the same period funding from trade receivables was lower year on year USD (6.0) million.

Cash flow from investing activities

Cash outflow from investing activities was USD (7.6) million for the year ended 31 December 2020, a decrease of USD 4.8million, or 39%, from USD (12.5) million for the year ended 31 December 2019. The change was a result of a reduction in the level of investment in fixed assets.

Cash flow from financing activities

Cash outflow from financing activities was USD (3.2) for the year ended 31 December 2020, an increase of USD 6.9 million, or 68%, from USD (10.1) for the year ended 31 December 2019. The change was primarily driven by the dividend payment in 2019 of USD (11.5) million.

Cash and cash equivalents at the end of the period

Cash and cash equivalents were USD 14.1 million for the year ended 31 December 2020, a decrease of USD (13.8) million, or 49%, from USD 27.9 million for the year ended 31 December 2019. The change was a result of the factors described above.

12.10.4. Cash flow for the year ended 31 December 2019 compared to the year ended 31 December 2018

Amounts in USD 000's	**2019**	**2018**
Net cash flows from operating activities...	42,606	(1,064)
Net cash flows from investing activities...	(12,466)	(4,037)
Net cash flows from financing activities...	(10,175)	4,958
Cash and cash equivalents at end 31 December......................................	27,891	7,926

Cash flow from operations

Cash inflow from operating activities was USD 42.6 million for the year ended 31 December 2019, an increase of USD 43.8 million, from USD (1.0) million for the year ended 31 December 2018. Although the cash flows from operating activities was USD 24 million lower in 2020 there was adjustment to cash flows for a non-cash share based payment expense of USD16.4 The improved cash flow was mainly related to an increase in funding from an increase of trade payables USD 24.9 million in 2019 together with a lower level of contributions to the "advance against decommissioning" (USD 3.3 million in 2019 versus USD 11.4 million in 2018).

Cash flow from investing activities

Cash outflow from investing activities was USD (12.5) million for the year ended 31 December 2019 from USD (4.0) million for the year ended 31 December 2018. The change was a result of investments in property, plant and equipment.

Cash flow from financing activities

Cash outflow from financing activities was USD (10.2) million for the year ended 31 December 2019, a decrease of USD (15.1) million, or 305%, from USD 4.9 million for the year ended 31 December 2018. The change was a result of dividend payments in 2019 of USD (15.1) million.

Cash and cash equivalents at the end of the period

Cash and cash equivalents were USD 27.9 million for the year ended 31 December 2019, an increase of USD 20 million, or 252%, from USD 7.9 million for the year ended 31 December 2018. The change was a result of the factors described above.

12.10.5. Financing arrangements

The following table sets forth the Group's consolidated financing arrangements and commitments as of 30 June 2021:

Amounts in USD millions	Outstanding amount as of 30 June 2021
Rasmala loan facility	
Principal	15.0
Repayment	(0.9)
Interest costs	0.9

Interest costs paid	(0.9)
Rasmala loan facility balance	14.1
Symero Loan facility	
Principal	3.9
Interest costs	0.2
Interest costs paid	(0.2)
Symero loan facility balance	3.9

The maturity profile in the table below shows contractual maturities of the main borrowings of the Group as at 30 June 2021 including estimated interest and principal payments, for the periods indicated. The numbers set out in the table below assumes completion of the Listing.

	Payment profile				
USD millions	2021	2022-2023	2024-2026	More than 5 years	Total
Rasmala loan repayments	4.1	10.0	-	-	14.1
Rasmala loan interest repayments	0.7	0.7	-	-	1.4
Symero loan repayments	-	3.9			3.9
Symero interest repayments	0.2	0.3			0.5

Please see below for a description of key terms and security under the Group's financing arrangements.

The Group has the following financing arrangements in place as at the date of this Prospectus:

The Group have a USD 15 million term loan facility in place with the Rasmala

On 3 May 2020, subsidiary company HAH arranged a secured debt facility of USD 15.0 million from Rasmala (London and Dubai based investor group) that had a 12-months' grace period and final maturity in November 2022. As at 30 September 2021, USD 3.3 million of the debt had been repaid, USD 10.0 million was payable within 12 months, and USD 1.7 million payable after one year. All or part of the debt may be repaid early with 30 days' notice with no financial penalties. The loan is repaid in monthly instalments after the initial grace period and carries an interest rate of 9% plus 12-month LIBOR payable monthly if the oil price is below 40 USD/bbl and 12.5% if the oil price is above 40 USD/bbl. The loan is secured against:

- The assignment of receivables by subsidiary company HEPCO;
- Pledge over one of the bank accounts of subsidiary company HAH;
- Pledge over one of the bank accounts of subsidiary company HEPCO;
- Pledge over shares in subsidiary companies, HAH and HEPCO;
- Assignment of inter-company loan agreement between HAH and HEPCO; and
- Corporate guarantees by PetroNor Australia and its subsidiaries PetroNor E&P Ltd. Cyprus and HEPCO.

The Rasmala loan has the following covenants and undertakings:

- Cash equal to three monthly instalments must be maintained on the bank accounts of HAH on a recurring basis;
- At least USD 6.0 million from HEPCO oil sales must be paid into the collection account on a 3-month rolling basis;
- PetroNor to maintain shareholding level in excess of 70% in subsidiary company HAH;
- HAH to maintain shareholding level in excess of 74.25% in subsidiary company HEPCO;
- HAH shareholder equity ratio shall not be less than 30%;
- HAH duty to report on financial statements, pledged bank account activity and oil inventory;
- Restrictions on distributions to HAH shareholders, unless sufficient liquidity with cash balances exceeding USD 10.0 million immediately before any such distribution, and distribution does not exceed 75% consolidated HAH net profit in any year.

The Group have a USD 3.9 million term loan facility in place with Symero

On 28 September 2020, subsidiary company Hemla Africa Holding AS paid a USD 3.9 Million dividend to minority interest and related party Symero Ltd. An amount equal to the dividend was immediately loaned to the Parent Company by Symero Ltd with interest rates matching those already provided by external financing and no security was provided for the loan. The maturity date is matched to the USD 15 Million facility from Rasmala. All covenants were complied with and there were no breaches during the year for both loans payable to Rasmala and Symero.

12.11. Financial risk and capital management

For a description of the Group's management of credit, liquidity, interest rate and foreign exchange risk, see the notes of the financial statements for the financial year ended 31 December 2020, included as Appendix C to this prospectus.

12.12. Investments

The Group's investing activities primarily relate to the acquisition of production licenses and related development costs.

12.12.1. Historical investments

The table below shows the Group's principal historical capital expenditures and investments derived from the combined statement of cash flows for the six months ended 30 June 2021 and 2020.

Amounts In USD 000's	**Six months ended 30 June**	
	2021	**2020**
Investment in property, plant, equipment and intangible assets – Congo	1,385	2,079

The table below shows the Group's principal historical capital expenditures and investments derived from the combined statement of cash flows for the years ended 31 December 2020, 2019 and 2018.

Amounts In USD 000's	**Year ended 31 December**		
	2020	**2019**	**2018**
Investment in property, plant, equipment and intangible assets – Congo (i)	4,615	12,466	4,037
Investment in property, plant, equipment and intangible assets – Gambia (ii)	3,007	-	-

(i) Investment in property, plant, equipment and intangible assets in Congo represent the Group's share of routine capital expenditure incurred by the operator on the asset During 2019 there was USD 8 million incremental CAPEX related to the Litanzi North project (acquisition and installation of Litanzi platform and preparation for drilling).

(ii) Investment in Gambia represents the signature bonus and the arbitration expenses incurred for the A4 license in Gambia.

Investment in field development is a major part of the Group's operations. The investments above consist of building requisite operating facilities, drilling of production wells along with installation of technologies to produce hydrocarbons.

12.12.2. Current and future investments

In 2019, the Group signed both an agreement with Panoro and a separate investment and shareholders agreement with YFP, as detailed in 8.2.6 "Nigeria – OML-113". As at the date of this Prospectus, ministerial consent for the transactions has been provided but is subject to the payment of USD 1 million for the assignment of OML 113 before 30 April 2022. On completion PetroNor will however recognise a USD 10.0 million new investment in the special purpose vehicle used to consolidate the interests in the OML-113 licence in Nigeria, to be held by YFP with PetroNor. As further detailed in the pro forma financial information set out in section 11.2 "Aje Transaction".

12.13. Tangible fixed assets

As at 30 June 2021, the Group's tangible fixed assets consists of USD 22.6 million in Property, Plant and Equipment and USD .01 million in Right of Use Assets. The Group is currently not aware of any environmental issues that may negatively affect the Group's utilization of its sites, equipment, or other assets, beyond what is described in Section 8.10 "Legal proceedings" in this Prospectus.

24 November 2021 marked the initiation of the drilling of the first of the 17 new wells planned for the infill drilling campaign offshore in Congo Brazzaville. Based on the forward estimates of the operator Perenco, PetroNor will invest approximately USD 80.0 million towards its share of the planned work program during 2021 to 2023. USD 26.0 million on new wells, USD 45.0 million on other capital expenditure and USD 12.0 towards the asset retirement obligation. Current expectations are that the increase in capital expenditure, compared to the levels in historical financial information, will be self-funded by the ongoing oil production in the PNGF Sud licence.

12.14. Related party transactions

For an overview of the Group's transactions with related parties, see the Group's Financial Statements for the years 2020 note 24, 2019 note 24 and 2018 note 17 included appended hereto as Appendix C to E to this Prospectus.

Related parties of the Company include key management, the Board of Directors, their close family members and enterprises which are controlled by these individuals. During the years ended December 31, 2020, 2019 and 2018, there was no revenue or associated cost of sales for products and services provided to any significant corporate shareholder.

Apart from the below related party transaction, there have not been any significant transactions with related parties year-to-date 2021 beyond what is considered as normal operations. See the notes in the Group's Interim Financial Statements for further details.

During the financial year of 2021, the Company has entered into the related party transactions as set out below.

Symero transaction

In February 2021, the Company announced that its net indirect interest in the PNGF Sud licenses in the Republic of Congo increased from 10.5% to 16.83% following the acquisition of 29.293% of the shares of Hemla Africa Holding AS (the majority shareholder of HEPCO) from Symero Ltd. (the "**Symero Transaction**") for a consideration of USD 18 million paid in-kind through issuance of new shares in PetroNor in conjunction with a private placement completed in the first half of 2021.

Symero is a company owned by NOR Energy AS, which in turn is controlled by former CEO of PetroNor, Knut Søvold, and former Director of PetroNor, Gerhard Ludvigsen, and therefore the Symero Transaction was considered a related party transaction at the time of completion, and as such was subject to the approval by the shareholders of the Company by ordinary resolution at an extraordinary general meeting of the Company.

Loan agreement with interim CEO, Mr. Pace

The Company entered into a loan agreement with Mr. Pace (interim CEO) for the amount to cover his tax payable on the 33,334 treasury shares that Mr. Pace was awarded upon his commencement of employment with the Company (then APCL) in November 2012.

Services agreement with Petromal LLC

Petromal LLC is the largest shareholder in the Company and since 2017 has had an agreement to provide technical and project management services. The current rate of USD 41,500 per month has been invoiced since April 2020.

12.15. Critical accounting policies and estimates

The preparation of the financial statements according to IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Estimates and judgments are evaluated on a continually basis and are based on historical experiences and other factors that are believed to be reasonable under the circumstances. The Company makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal the actual outcome.

Please see note 3 in the financial statements for the year ended 31 December 2020, attached hereto as Appendix C, for details on the accounting policies and estimates.

12.16. Trend information

12.16.1. Production, sales and selling price

During Q1 2021, the gross production in the PNGF Sud fields in the Republic of Congo was 21,716 bopd, resulting in a net to PetroNor production of 2483 bopd. In Q2 2021, production has been below expectation primarily for two reasons; COVID has delayed the start of infill drilling start on Litanzi from Q2 2021 to Q4 2021 and delays in materials procurement for all operators in the country.

The latter situation has been resolved and the Operator is pursuing the maintenance lag. Thus, following a reduced production in Q2, production is now back around 21,000 bopd and increasing ahead of the start of infill drilling. During H1/Q2 2021, gross production was 20,289/19,061 bopd, resulting in a net to PetroNor production of 3,372/3,208 bopd.

Oil & gas revenue for the first quarter of 2021 was (net of royalties & taxes) USD 12.88 million arising from sale of 0.22 million barrels of crude oil at an average price of USD 58.68 per barrel. In the prior year, 0.27 million barrels of crude oil was sold during the same period at an average price of USD 40.66, resulting in a revenue of USD 10.97 million. During the second quarter of 2021, there were two liftings that meant oil & gas revenue was (net of royalties & taxes) USD 13.6 million arising from sale of 0.20 million barrels of crude oil at an average price of USD 67.61 per barrel. In the prior year, 0.20 million barrels of crude oil was sold during the same period at an average price of USD 32.82, resulting in a revenue of USD 6.5 million.

Amounts in USD'000 (Unaudited)	**Six months ended 30 June** **2021**	 **2020**
Revenue from contracts from customers		
Revenue from sales of petroleum products	26,460	17,443
Other revenue		
Assignment of tax oil	14,654	8,083
Assignment of royalties	7,061	4,737
Total revenue	48,174	30,263
Number of liftings	4	3
Quantity of oil lifted (Barrels)	420,360	467,003
Average selling price (USD per barrel)	62.95	37.35
Quantity of net oil produced after royalty, cost oil and tax oil (Barrels)	402,701	520,611

A half year to half year comparison between the six months to June 2021 and June 2020 shows that increasing oil prices have offset lower sales volumes

12.16.2. Cost of Sales

Cost of sales have increased from USD 10.7 million to USD 14.5 million. The main part of the increase came from the royalty in kind that is valorized at oil price, a significant increase of oil price in the first half of 2021 compared to the first half 2020 so what there an increase of the royalty in-kind by USD 2.3 million. USD 0.8 million increase on OPEX related to the resumption of normal activity following an improvement in the pandemic situation.

USD'000 (Unaudited)	**Six months ended 30 June** 2021	 2020
Operating expenses	7,342	6,509
Royalty	7,061	4,737
Movement in oil inventory	114	(508)
	14,517	10,738

12.17. Significant changes

12.17.1. Financial performance

In the trading update released by the Company on 26 November 2021 for the period ended 30 September 2021, it was reported that total revenues came in at USD 18.3 million with an EBITDA result of USD 9.6 million. Underlift in the quarter resulted in a temporary reduction in both revenues and EBITDA compared with the previous quarter. The underlift also led to an inventory build-up during the third quarter. However, for the fourth quarter, PetroNor anticipates lifting volumes in excess of 300 kbbl, up from 94 kbbl in the third quarter, that will correct the timing difference for revenue recognition on lifting dates.

Other than the above changes, there has been no significant change in the Group's financial performance which has occurred since the end of the last financial period for which the Interim Financial Statements has been published to the date of this Prospectus.

12.17.2. Financial position

On 9 July 2021, the 224,727,273 ordinary shares related to Tranche 2a and 2b of the Private Placement were issued, whereof: 138,763,636 ordinary shares for Tranche 2a of the Private Placement issued in kind as consideration for the Symero transaction, and 85,963,637 ordinary shares for Tranche 2b of the Private Placement issued for cash.

On 21 September 2021, 46,234,809 ordinary shares related to a subsequent repair offering of shares were issued.

Other than the above, there has been no significant changes in the financial position of the group which has occurred since the end of the last financial period for which the Interim Financial Statements have been published.

13. BOARD OF DIRECTORS, MANAGEMENT, EMPLOYEES AND CORPORATE GOVERNANCE

13.1. Introduction

The General Meeting is the highest authority of the Company. All shareholders of the Company are entitled to attend and vote at General Meetings of the Company and to table draft resolutions for items to be included on the agenda for a General Meeting.

The overall management of the Group is vested in the Board of Directors and the Group's Management. In accordance with Norwegian law, the Board of Directors is responsible for, among other things, supervising the general and day-to-day management of the Group's business, ensuring proper organisation, preparing plans and budgets for its activities, ensuring that the Group's activities, accounts and assets management are subject to adequate controls and undertaking investigations necessary to perform its duties.

Management is responsible for the day-to-day management of the Group's operations in accordance with Norwegian law and instructions prepared by the Board of Directors. Among other responsibilities, the Group's chief executive officer (the "**CEO**") is responsible for keeping the Group's accounts in accordance with prevailing Norwegian legislation and regulations and for managing the Group's assets in a responsible manner. In addition, the CEO must, pursuant to Norwegian law, brief the Board of Directors about the Group's activities, financial position and operating results at least once per month.

13.2. The Board of Directors

13.2.1. Overview of the Board of Directors

The Articles of Association provide that the Board of Directors shall consist of of up to 7 Board Members elected by the Company's shareholders. The names, positions, current term of office and business addresses of the Board Members as at the date of this Prospectus are set out in the table below.

Name	Position	Served since	Term expires
Eyas A. Alhomouz	Chair	2021	2023
Gro Gauthun Kielland	Board Member	2021	2023
Ingvil Smines Tybring-Gjedde	Board Member	2021	2023
Joseph Kamal Iskander Mina	Board Member	2021	2023

The composition of the Board of Directors is in compliance with the independence requirements of the Corporate Governance Code (as defined below), meaning that (i) the majority of the shareholder elected members of the Board of Directors are independent of the Company's executive management and material business contacts and (ii) at least two of the shareholder elected Board Members are independent of the Company's main shareholders (shareholders holding more than 10% of the Shares of the Company).

The Company's registered business address, Frøyas gate 13, 0273 Oslo, Norway serves as c/o address for the Board Members in relation to their directorship of the Company.

The Shares held by the Board Members as at the date of this Prospectus are set out in Section 13.2.3 "Shares held by members of the Board".

13.2.2. Brief biographies of the Board Members

Set out below are brief biographies of the Board Members. The biographies include each Board Member's relevant management expertise and experience, an indication of any significant principal activities performed by them outside the Company and names of companies and partnerships of which a Board Member is or has been a member of the administrative management or supervisory bodies or partner in the previous five years.

Eyas A. Alhomouz, Chair

Mr. Alhomouz has a strong experience from the oil and gas sector covering the US, North Africa, and the Middle East. He began his career with Schlumberger Oilfield Service as a wireline engineer in Midland, Texas. From there he went on to work for Cromwell Energy in Denver, Colorado, in the role of international business development manager. Then, as a COO and Financial Director of Prism Seismic, he oversaw the growth of the Colorado based consulting and oil and gas software development firm and later the acquisition of the company by Sigma Cubed where, post-acquisition of Prism Seismic, he went on to serve as a director of business development, Middle East. Mr. Alhomouz's career then took him to Qatar as a General Manager of Jaidah Energy, an Omani-Qatari owned company servicing the oil and gas sector in Qatar. He is currently the CEO of Petromal Sole Proprietorship LLC, a subsidiary of National Holding in Abu Dhabi. Mr. Alhomouz graduated from Brigham Young University in Provo, UT with a degree in Chemical Engineering and from the Colorado School of Mines, in Golden, CO with a master's degree in Mineral and Energy Economics.

Current directorships and senior management positions....	Petromal Sole Proprietorship LLC (Chief Executive Officer)
Previous directorships and senior management positions–- last five years..	Jaidah Energy (General manager)

Gro Gauthun Kielland, Board Member

Mrs. Kielland has over 30 years of experience having held a number of leading positions in the oil and gas industry both in Norway and abroad, among others as CEO of BP Norway. Her professional experience includes work related to both operations and field development, as well as HSE. Mrs. Kielland holds an MSc in Mechanical Engineering from the Norwegian University of Science and Technology (NTNU).

Current directorships and senior management positions....	Beyonder AS (Chairman), ASCO Norge AS (Chairman), BUHR AS (Chairman), FloPetrol Well Barrier AS (Non-Executive Director), Flux Group AS (Non-Executive Director), Hagrola Consulting AS (Chairman), S3-ID AS (Chairman), Ulstein Group ASA (Non-Executive Director)
Previous directorships and senior management positions–- last five years..	AkerBP (Non-Executive Director), Agile Rig and Modules AS (Chairman), Agility Group AS (Non-Executive Director, Chairman), Align (Non-Executive Director, Chairman), FalckNutec (Non-Executive Director), Momek (Chairman), Norwegian Biotech AS (Chairman), Minox Technology AS (Chairman), Stavanger Symphonic Orchestra (Vice Chair of the Board), Hagrola Consulting AS (CEO)

Ingvil Smines Tybring-Gjedde, Board Member

Experienced former Norwegian Minister of National Public Security with overall responsibility of public safety, emergency planning, and cybersecurity. Mrs. Tybring-Gjedde was also Minister of Svalbard and the Norwegian polar regions. Before her position as Minister, she served as Deputy Minister in the Ministry of Petroleum and Energy for 4 years, with a portfolio of exploration policy, development, and operations, exploration activity as well as following the Ministry's contact with other petroleum producing countries and international forums in addition to the government's national climate policy, global environmental issues and the government's CCs full scale project. Mrs. Tybring-Gjedde has a demonstrated history of working in the O&G, energy, and renewable industry in private and state-owned companies in various leading positions for more than 20 years. Mrs. Smines Tybring-Gjedde graduated from BI Norwegian Business School with a Master's degree in Management Programs, with strong focus in "Interaction and Leadership" and "Strategy".

Current directorships and senior management positions....	Norge Mining PLC (Non-Executive Director), Earth, Wind & Power AS (CEO)
Previous directorships and senior management positions - last five years..	Minister of Public Security, State Secretary / Vice Minister of the Ministry of Petroleum

Joseph Iskander, Board Member

Mr. Iskander brings over 20 years of experience in the financial services industry, covering asset management, private equity, portfolio management, financial restructuring, research, banking, and audit. He began his career at Deloitte & Touche (Egypt) as an auditor. Mr. Iskander served as non-executive director on the boards of EFG Hermes in Egypt, Oasis Capital Bank in Bahrain, Sun Hung Kai & Co in Hong Kong, Qalaa Holdings in Egypt, Emirates Retakaful in UAE, Marfin Laiki Bank in Cyprus and Marfin Investment Group in Greece. Mr. Iskander headed the research team at Egypt's Prime Investments and was earlier an Investment Advisor at Commercial International Bank (CIB). He then went on and joined Dubai Group as an Investment Manager in 2004 and has worked on a range of M&A transactions, advisory services, asset management, and private equity transactions with a collective value in excess of USD 8 billion. Mr. Iskander was Managing Director of Asset Management at Dubai Group and the former Head of Research at Dubai Capital Group until 2009. He joined Emirates International Investment Company in July of 2017 as the Director of Private Equity spearheading and managing EIIC's investments. He holds a Degree in Accounting and Finance with high distinction from Helwan University, Egypt (1997).

Current directorships and senior management positions....	EIIC (Head of Investments), Abu Dhabi Islamic Bank Egypt (Director), Entrust Capital (CEO)

Previous directorships and senior management positions–- last five years..	EFG Hermes Egypt (Non-Executive Director), Oasis Capital Bank Bahrain (Non-Executive Director), Sun Hung Kai & Co Hong Kong (Non-Executive Director), Qalaa Holdings Egypt (Non-Executive Director), Emirates Retakaful UAE (NonExecutive Director), Marfin Laiki Bank Cyprus (Non-Executive Director), Marfin Investment Group Greece (Non-Executive Director), Dubai Group (Managing Director of Asset Management)

13.2.3. Shares held by the members of the Board

At the time of this Prospectus, none of the Directors hold shares or options in the Company. Although Mr. Alhomouz has no personal interests in shares and options, he has influence over 481,481,666 shares as the CEO of significant shareholder Petromal LLC.

13.3. Management

13.3.1. Overview

The Compan''s Management team consists of 5 individuals: CEO, CTO, Exploration Director, Strategy and Contracts Manager and Group Financial Controller.

The Shares held by members of the Management as at the date of this Prospectus are set out in Section 13.3.3""Shares held by the members of Managemen"".

The names of the members of Management as at the date of this Prospectus, and their respective positions, are presented in the table below:

Name	Current position within the Group	Engaged with the Group since
Jens Pace	Interim Chief Executive Officer	1 October 2012
Claus Frimann-Dahl	Chief Technical Officer	4 June 2018
Michael Barrett	Exploration Director	12 August 2011
Emad Sultan	Strategy and Contracts Manager	28 March 2017
Chris Butler	Group Financial Controller	19 March 2010

The Compan''s registered business address, Frøyas gate 13, 0273 Oslo, Norway, serves as c/o address for the members of the Management in relation to their employment with the Group.

13.3.2. Brief biographies of the members of the Management

Set out below are brief biographies of the members of the Management. The biographies include the members of Managemen''s relevant management expertise and experience, an indication of any significant principal activities performed by them outside the Company and names of companies and partnerships of which a member of the Management is or has been a member of the administrative, management or supervisory bodies or partner the previous five years.

George Jens Soby Pace, Interim Chief Executive Officer (CEO)

Mr. Pace is a highly regarded geoscientist, who has had a successful career at BP, and its heritage company Amoco (UK) Exploration Company. Mr. Pace has held senior positions at BP for over 10 years, gaining exploration and production experience in Africa, namely: Algeria, Angola, Congo, Gabon and Libya. In addition, he has experience in Europe, Russia and Trinidad. He has contributed to a number of BP's exploration discoveries over his career, and has managed a very large and active exploration portfolio for BP in Africa. Additionally, Mr. Pace has gained highly sought-after experience in the areas of field development and as a commercial manager, dealing with national oil companies and African governments. Mr. Pace joined African Petroleum as Chief Operating Officer in October 2012 and was promoted to Chief Executive Officer in September 2015. Following the merger with PetroNor E&P Ltd on 30 August 2019, Mr. Pace resigned as Chief Executive Officer on 29 February 2020, but remained on the Board as a Non-Executive Director. On 9 February 2022, Mr. Pace resigned as a Non-Executive Director to act as the temporary CEO until a new CEO is found. Mr. Pace holds a BSc in Geology and Oceanography from the University of Wales and an MSc in Geophysics from Imperial College, London, UK.

Current directorships and senior management positions....	Tafiti Oil Limited (Director), Wingate Consulting Ltd (Director), Quattro Energy Limited (CEO)
Previous directorships and senior management positions - last five years..	None

Claus Frimann-Dahl, Chief technical officer (CTO)

Mr. Frimann-Dahl has 30 years' experience from the oil and gas industry, with managerial and technical roles. His experience covers operational roles with Phillips Petroleum, Norsk Hydro and Hess in the North Sea Norway and Denmark, Russia, Egypt and the US. He was the co-founder of Ener Petroleum which was later acquired by Dana Petroleum and KNOC. He holds a BSc in Petroleum Engineering from Texas A&M University and an MSc from the University of Trondheim (NTH).

Current directorships and senior management positions....	Snake Oil AS (Chairman), Vestre Ullern Boligsameie (Chairman)
Previous directorships and senior management positions - last five years..	Tellus Petroleum AS (Director), Acumen Energy AS (Director), Grini Industrier AS (Director)

Michael Barrett, Exploration Director

Mr. Barrett has over 30 years global exploration experience from his career at Chevron Corporation, and more recently at Addax/Sinopec International. Mr. Barrett has held senior positions at Chevron and Addax Petroleum, gaining substantial exploration and operations experience in Africa, namely: Angola, Cameroon, Gabon, Kurdistan and Nigeria, having also extended experience in Australia. Mr. Barrett has held a variety of technical roles covering exploration and new ventures, and was part of Chevron's global Exploration Review Team, specialising in Play and Prospect risk assessment, volumetric analysis, commercial evaluation and portfolio management. Mr. Barrett also brings added strength to the team with his background in quantitative geophysics, stratigraphic interpretation workflows and 3D visualisation. Mr. Barrett has a BSc in Geology & Geophysics from Durham University and a MSc in Petroleum Geology & Geophysics from Imperial College, Royal School of Mines.

Current directorships and senior management positions....	N/a
Previous directorships and senior management positions - last five years..	N/a

Emad Sultan, Strategy and Contracts Manager

Mr. Sultan has 20 years of international Exploration & Production experience. He has held multiple operation and marketing management positions with international oil field services companies. He has also worked in a number of technical, contracting and strategy management roles with major oil and gas operators. Mr. Sultan holds a BSc Mechanical Engineering degree from the University of Washington.

Current directorships and senior management positions....	Petromal Sole Proprietorship (UAE Business Development Director)
Previous directorships and senior management positions - last five years..	Weatherford (UAE Sales and Marketing Manager), NOV (Middle East Drilling Technologies Manager), ADNOC Offshore (Drilling Contract and Technology Manager)

Chris Butler, Group Financial Controller

Mr. Butler has over 16 years of financial and corporate experience from positions in public practice, oil & gas and mining spread over Africa, Asia and Europe, with roles that included financial reporting, contract negotiations, M&A, due diligence, treasury and several system implementations. Mr. Butler is a Fellow of the Institute of Chartered Accountants in England and Wales and has a BSc in Physics from Warwick University.

Current directorships and senior management positions....	Technical Solutions International 1986 Ltd (Director)
Previous directorships and senior management positions - last five years..	N/a

13.3.3. Shares held by the members of Management

The following table sets forth the number of options and shares beneficially owned by each of the Company's members of management as of the date of this Prospectus:

Name	Position	Shares	Options
Jens Pace	Interim Chief Executive Officer	1,498,858	None
Claus Frimann-Dahl[1]	Chief Technical Officer	604,545	None
Michael Barrett	Exploration Director	1,151,667	None
Emad Sultan	Strategy and Contracts Manager	None	None
Chris Butler	Group Financial Controller	234,296	None

[1] Mr. Frimann-Dahl's shares are held in the name of Snake Oil AS, a company entirely owned by Mr. Frimann-Dahl.

13.4. Remuneration and benefits

13.4.1. Remuneration of the Board of Directors

The Chairman of the Board of PetroNor Australia (prior to the Redomiciliation) has received remuneration of USD 856,488 from 1 January 2019 to 31 December 2020. The remuneration received by the remaining board members of PetroNor Australia (prior to the Redomiciliation) was USD 3,527,282 from 1 January 2019 to 31 December 2020.

Name	**Designation**	**2019[1]**	**2020**	**SUM**
Eyas Alhomouz[2]	Chairman of the Board	481,488	375,000	856,488
Jens Pace[3]	Director and interim CEO	493,209	532,975	1,026,184
Gerhard Ludvigsen[4]	Director and Business Development Manager	452,414	344,410	796,824
David King[5]	Director	20,000	(3,000)	17,000
Bjarne Moe[6]	Director	19,000	-	19,000
Tim Turner[7]	Director	11,056	1,760	12,816
Knut Søvold[8]	Director and COO/CEO	450,891	343,053	793,944
Stephen West[9]	Director and CFO	384,067	412,879	796,946
Joseph Iskander[10]	Director	-	-	-
Alex Neuling[11]	Director	-	24,403	24,403
Roger Steinepreis[12]	Director	-	22,600	22,600
Ingvil S. Tybring-Gjedde[13]	Director	-	17,565	17,565
Total		**2,312,125**	**2,071,645**	**4,383,770**

[1]Pro-forma remuneration for directors from Australian company PetroNor E&P Ltd, assuming the reverse acquisition with APCL had taken place on 1 January 2019.
[2]Appointed 30 August 2019. Remuneration includes USD 120,000 per year for his position as Chairman of the Board of Hemla E&P Congo S.A.
[3]On 29 February 2020, Mr. Pace resigned as CEO but remained on the board as a Non-Exec Director. Mr. Pace agreed to waive his Non-Exec Director remuneration for one year in recognition of the termination fees agreed for resigning as CEO. Mr. Pace was appointed interim CEO of PetroNor Australia on 16 December 2021.
[4]Appointed as Director 29 May 2020, resigned 31 January 2021. Remuneration includes USD 66,000 per year for his position as Director of Hemla E&P Congo S.A. and as Business Development Manager.
[5]Resigned 1 February 2020.
[6]Resigned 18 October 2019.
[7]Resigned 8 February 2020.
[8]Appointed as Director and COO 30 August 2019, resigned 29 May 2020. Appointed CEO 29 on February 2020 and replaced as CEO 16 December 2021. Remuneration includes USD 66,000 per year for his position as Director of Hemla E&P Congo S.A.
[9]Resigned 29 February 2020.
[10]Appointed on 30 August 2019, agreed to waive his remuneration.
[11]Appointed as Director 6 April 2020.
[12]Appointed as Director 29 May 2020.

13.4.2. Remuneration of the Management

The below table sets forth the amount of remuneration paid by the to the Management of the Group for the financial year ended 31 December 2020.

Name	**Designation**	**Salary and fees**	**Other cash benefits**	**Post-employment benefits**	**Termination fees**	**Total**
		USD	USD	USD	USD	USD
Knut Søvold[1]	Exec Director & CEO	254,107	832	22,114	-	277,053
Jens Pace[2]	Exec Director & interim CEO	83,039	1,318	-	448,618	532,975
Stephen West[3]	Exec Director & CFO	58,884	2,030	5,888	346,077	412,879
Gerhard Ludvigsen[4]	Exec Director & Business Development Manager	254,107	832	23,471	-	278,410
Claus Frimann-Dahl	Chief Technical Officer	200,432	747	18,962	-	220,141
Michael Barrett	Exploration Manager	246,595	2,131	-	-	248,726
Chris Butler	Group Financial Controller	147,766	5,766	14,777	-	168,309
Emad Sultan[5]	Strategy & Contracts Manager	232,500	-	-	-	232,500
Total		**1,477,430**	**13,656**	**85,212**	**794,695**	**2,370,993**

[1]Appointed as Director and COO 30 August 2019, resigned 29 May 2020 as Director. Appointed CEO 29 February 2020, replaced as CEO 16 December 2021. Excludes remuneration for his position as Director of Hemla E&P Congo S.A.
[2]On 29 February 2020, Mr. Pace resigned as CEO but remained on the board as a Non-Exec Director. Mr. Pace agreed to waive his Non-Exec Director remuneration for one year in recognition of the termination fees agreed for resigning as CEO. Mr. Pace was appointed Interim CEO of PetroNor Australia on 16 December 2021.
[3]Resigned 29 February 2020.

[4]Business Development Manager from 30 August 2019. Appointed as Director 29 May 2020, resigned 31 January 2021. Excludes remuneration for his position as Director of Hemla E&P Congo S.A.
[5]Remuneration is not paid to the individual, as fees are included in a monthly lump sum charged by related party Petromal LLC, above figures represent the company's fair value estimate of associated costs for the individual's services.

13.5. Share incentive program

The Company does not have a bonus incentive scheme or an option scheme for its employees as at the date of this Prospectus, but will consider to implement an incentive scheme involving employees in the equity of the Company after the Listing date in accordance with market standards.

13.6. Benefits upon termination

There are no contractual benefits for staff upon termination, and the termination contractual notice periods for Management are as follows:

- Claus Frimann-Dahl, CTO – 3 months
- Michael Barrett, Exploration Director – 3 months
- Chris Butler, Group Financial Controller – 3 months

13.7. Pension and retirement benefits

The Group has no defined benefit pension schemes, however, there are defined contribution schemes. The Group's pension schemes vary depending on the operative country and requirements under local law. Group employees are included in the Group's defined contribution pension schemes in accordance with mandatory law in the relevant operative country.

There is no pension accrued liability cost for members of the Management employed in the Group as of December 31, 2020. The Group has no pension or retirement benefits for its Board Members.

13.8. Employees and long term contractors

As of 30 June 2020 the Group had 35 full time employees and long term contractors ("**FTEs**") in Europe, West Africa, Australia and Middle East. The table below shows the development in the number of FTEs for the years ended 31 December 2020, 2019 and 2018 and for the six month interim periods ended 30 June 2021 and 2020, including a breakdown of FTEs by location.

	As of 30 June 2021	As of 30 June 2020	As of 31 December 2020	As of 31 December 2019	As of 31 December 2018
Europe	17	11	12	13	12
West Africa	13	12	13	13	13
Australia	1	1	1	1	1
Middle East	4	4	4	4	2
Total	35	28	30	31	28

The below table below shows the number of FTEs of the Group by main category of activity.

	As of 30 June 2021
Finance	7
Operations	12
Facilities & HSE	1
Sub-surface	7
Administration / CoSec	4

13.9. Nomination committee

The Company's Articles of Association provide for a nomination committee elected by the general meeting. The nomination committee shall have up to 3 members and shall, at the outset, consists of 2 members, elected for a term ending with the annual general meeting of the Company in 2022. The composition of the Company's nomination committee will subject to and with effect from Listing comprise of Mr. Eyas Alhomouz (committee chair) and Mr. Jens Pace (committee member). Due to the Company's current shareholder composition, the Nomination Committee shall not necessarily be independent of the major shareholders and the Company will continuously consider this matter and whether to later propose a more independent appointment of the nomination committee.

The nomination committee shall present proposals to the general meeting regarding election of the chair of the Board, board members and any deputy members of the Board and election of members of the nomination committee.

The nomination committee shall also present proposals to the general meeting for remuneration of the Board and the nomination committee.

13.10. Audit and risk committee

The Board of Directors has, with effect from Listing, established an audit and risk committee. The appointed members of the audit and risk committee are Mr. Eyas Alhomouz (committee chair), Mrs. Gro Kielland (committee member) and Mr. Joseph Iskander (committee member), and the composition of the audit committee fulfils the required qualifications and competence in accounting and auditing under the Norwegian Public Limited Liability Companies Act.

The function of the audit committee is to prepare matters to be considered by the Board of Directors and to support the Board of Directors in the exercise of its management and supervisory responsibilities relating to financial reporting, statutory audit and internal control.

The audit committee shall report and make recommendations to the Board of Directors, but the Board of Directors retains responsibility for implement such recommendations.

13.11. Remuneration committee

The Board of Directors has, with effect from Listing, established a remuneration committee. The remuneration committee are composed of Mr. Eyas Alhomouz (committee chair), Mrs. Gro Kielland (committee member) and Mrs. Ingvil Smines Tybring-Gjedde (committee member).

The purpose of the remuneration committee is to evaluate and propose the compensation of the Company's CEO and other members of the executive management team and issue an annual report on the compensation of the executive management team, which shall be included in the Company's annual accounts pursuant to applicable rules and regulations, including accounting standards, promulgated from time to time.

The remuneration committee shall report and make recommendations to the Board of Directors, but the Board of Directors retains responsibility for implement such recommendations.

13.12. Corporate governance

The Company has adopted and implemented a corporate governance regime which complies with the Norwegian Code of Practice for Corporate Governance, dated 17 October 2018 (the "**Corporate Governance Code**").

Due to the Company's current shareholder composition with a few, large shareholders who may control the outcome of board appointments, the Nomination Committee (as further described in Section 13.9 "Nomination committee") currently consist of the chairperson of the Board and the CEO as the members. The Board will continuously consider this practice and whether to later propose to the shareholders that changes to the composition of the Nomination Committee should be made made.

13.13. Conflict of interests

Mr. Alhomouz has no personal interest in shares or options but has influence over 481,481,666 shares as the CEO of the majority shareholder Petromal.

The Company has furthermore entered into a loan agreement with Mr. Pace (interim CEO) for the amount to cover his tax payable on the 33,334 treasury shares that Mr. Pace was awarded upon his commencement of employment with the Company (then APCL) in November 2012.

Other than as described herein there are, to the Company’s knowledge, no other potential conflicts of interests between any duties to the Company or its subsidiaries, of any of the Board members or members of the senior management and their private interests and/or other duties. There are no family relations between any of the Company’s Board members or members of senior management.

There are no arrangements or understanding with major shareholders, customers, suppliers or others regarding membership of the Board of Directors or the senior management.

13.14. Convictions for fraudulent offences, bankruptcies, public incrimination, etc.

During the last five years preceding the date of this Prospectus, none of the Board Members or the members of the Management has, or had, as applicable:

- any convictions in relation to fraudulent offences;

- been involved in any bankruptcies, receiverships, liquidations or companies put into administration where he/she has acted as a member of the administrative, management or supervisory body of a company, nor as partner, founder or senior manager of a company; or

- received any official public incrimination and/or sanctions by statutory or regulatory authorities (including designated professional bodies), nor been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of an issuer or from acting in the management or conduct of affairs of any issuer.

To the Company's knowledge, there are currently no actual or potential conflicts of interest between the Company and the private interests or other duties of any of the members of the Management or the Board of Directors, including any family relationships between such persons.

14. CORPORATE INFORMATION AND DESCRIPTION OF THE SHARE CAPITAL

The following is a summary of certain corporate information and material information relating to the Shares and share capital of the Company and certain other shareholder matters, including summaries of certain provisions of the Articles of Association and applicable Norwegian law in effect as at the date of this Prospectus. The summary does not purport to be complete and is qualified in its entirety by the Articles of Association, included in Appendix A of this Prospectus, and applicable laws.

14.1. Company corporate information

The Company's registered name is PetroNor E&P ASA. The Company is a public limited liability company organised and registered under the laws of Norway pursuant to the Norwegian Public Limited Liability Companies Act. The Company's registered office is in the municipality of Oslo, Norway. The Company was incorporated in Norway on 1 October 2021 as a public limited liability company in connection with the Redomiciliation. The Company's registration number in the Norwegian Register of Business Enterprises is 927 866 951 and its LEI code is 984500AEEH2D2AK42C11.

The Shares, have been created under the Norwegian Public Limited Liability Companies Act. The Shares are registered in book-entry form with the VPS under ISIN NO 001 1157232. The Company's register of shareholders in the VPS is administrated by the VPS Registrar who are in charge of keeping the records. There are no restrictions on the transferrability of the Shares.

The Company's registered office is located at Frøyas gate 13, 0273 Oslo, Norway, its main telephone number at that address is +47 949 83 159 and its e-mail is info@petronorep.com. The Company's website can be found at www.petronorep.com. The content of www.petronorep.com is not incorporated by reference into, or otherwise form part of, this Prospectus.

14.2. Legal structure

The Company is the ultimate parent company in the Group. The Company is not an operative entity, and the Group's operations are thereby carried out through the Company's operating subsidiaries. The following table sets out information about the Company and its directly or indirectly owned subsidiaries and affiliated entities:

Company	Tiered subsidiary	Country of incorporation	Effective % ownership
PetroNor E&P ASA	-	Norway	-
PetroNor E&P Ltd.	First tier	Australia	100%
African Petroleum Corporation Limited	Second-tier	Cayman Islands	100%
PetroNor E&P Gambia Limited	Third-tier	Cayman Islands	100%
APCL Gambia B.V.	Fourth tier	Netherlands	100%
African Petroleum Senegal Limited	Third-tier	Cayman Islands	90%[1]
African Petroleum Senegal SAU	Fourth-tier	Senegal	90%
African Petroleum Cote d'Ivoire Limited	Third Tier	Cayman Islands	100%
PetroNor E&P Services Limited	Third-tier	United Kingdom	100%
PetroNor E&P Ltd.	Fourth-tier	United Kingdom	100%
PetroNor E&P Limited	Second Tier	Cyprus	100%
Hemla Africa Holding AS	Third-tier	Norway	100%
Hemla E&P Congo S.A.	Fourth-tier	Republic of Congo	84.15%[2]
PetroNor E&P Services AS	Third-tier	Norway	100%
PetroNor E&P Ltd	Fourth-tier	Nigeria	100%
Aje Production AS	Fourth-tier	Norway	100%
PetroNor E&P AB	Fourth-tier	Sweden	100%

1 Remaining 10% shareholding held by Prestamex Limited

2 Remaining 15.85% shareholding held by MGI International SA, Mr. Okongo and Mr. Kostveit, owning 0.1%, 15%, and 0.75% respectively

14.3. Share capital and share capital history

As at the date of this Prospectus, the Company's share capital is NOK 1,326,991.006 divided in 1,326,991,006 Shares, each with a nominal value of NOK 0.001. All Shares are validly issued, fully paid and non-assessable.

The Company has one class of shares. No more than 10% of capital has not been paid for with assets other than cash during this period.

As at the date of this Prospectus, the Group owns no Shares as treasury shares.

Please refer to section 14.6 "Authorisations to increase the share capital, to issue Shares" for the authorisations granted to the Board of Directors to increase the share capital of the Company.

The table below shows the development in the Company's share capital for the period covered by the historical financial information for the Company, i.e. from the date of incorporation being 1 October and up to the date of this Prospectus:

Date of registration	Type of change	Change in share capital (NOK)	Subscription price per share (NOK)	Nominal value (NOK)	New number of Shares	New share capital (NOK)
1 October 2021	Incorporation of the Company	1,000,000	-	10.00	100,000	1,000,000
24 February 2022	Share capital reduction	-1,000,000	-	-	0	0
24 February 2022	Share capital increase by issuance of shares through contribution in kind	1,326,991.006	1 share in PetroNor Australia (contribution in kind)	0.001	1,326,991,006	1,326,991.006

The current share capital of the Group has been paid for with assets other than cash through by the increase in share capital from zero to 1,326,991.006 through contribution in-kind. Please refer to section 8.5 "History of the Group" for a further description of the share capital reduction and share capital increase through a contribution in kind in relation to the Australian scheme of arrangement.

Other than as set out above, there have been no changes to the Company's share capital or the number of Shares of the Company from the start of the period covered by the historical financial information up to the date of this Prospectus.

The Company expects to carry out a revere share split after the Listing in order to satisfy the listing requirements as concerns a minimum value of NOK 10 per share.

14.4. Admission to trading

The Company applied for admission to trading of its Shares on Oslo Børs on 27 October 2021. The board of directors of Oslo Børs approved the listing application of the Company on 16 February 2022, subject to certain conditions being met prior to the Listing date.

The Company currently expects commencement of trading in the Shares on Oslo Børs on or around 28 February 2022. The Company has not applied for admission to trading of the Shares on any other stock exchange, regulated market or multilateral trading facility (MTF).

14.5. Ownership structure

As at the date on or about the date of this Prospectus, the Company has 3617 shareholders. An overview of the top 6 largest shareholders, including the shareholders holding 5% or more of the Shares of the Company as at the date on or about this Prospectus is set out below:

#	Shareholder	Number of shares	Per cent
1	Petromal LLC*	481,481,666	36.28%
2	NOR Energy AS**	139,470,623	10.51%
3	Symero Limited***	138,763,636	10.46%
4	Ambolt Invest AS	87,583,283	6.60%
5	Gulshagen III AS****	45,000,000	3.39%
6	Gulshagen IV AS****	45,000,000	3.39%

**Non-Executive Chairman, Mr. Alhomouz is the CEO of Petromal LLC. 109,520,419 of the shares held by Petromal LLC are recorded in the name of nominee company, Clearstream Banking S.A. on behalf of Petromal LLC.*
***NOR Energy AS is a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through indirect beneficial interest. 90,000,000 shares held by NOR Energy AS are pledged in favour of DNB Bank as security for a loan facility.*
****Symero Limited is a 100% owned subsidiary of NOR Energy AS.*
*****Gulshagen III AS and Gulshagen IV are companies controlled by Mr. Søvold through an indirect beneficial interest*

Shareholders owning 5% or more of the Shares have an interest in the Company's share capital which is notifiable pursuant to the Norwegian Securities Trading Act. See Section 15.7 "Disclosure obligations" for a description of the disclosure obligations pursuant to the Norwegian Securities Trading Act.

Other than as described herein, the Company is not aware of any persons or entities who, directly or indirectly, jointly or severally, will exercise or could exercise control over the Company. The Company is not aware of any arrangements the operation of which may at a subsequent date result in a change of control of the Company.

No particular measures are initiated to ensure that control is not abused by large shareholders. Minority shareholders are protected from abuse by relevant regulations in inter alia the Norwegian Public Limited Liability Companies Act and the Norwegian Securities Act. See Section 14.9.2 "Certain aspects of Norwegian corporate law" and 15.10 "Compulsory acquisition" for further information.

The Shares have not been subject to any public takeover bids for the period covered by the Financial Information.

14.6. Authorisations to increase the share capital, to issue Shares and to acquire Shares

As of the date of this Prospectus, the Company is authorised to increase the share capital with up to NOK 461,793.70, equivalent to a total of 461,793,700 shares. The aforementioned authorisation was granted by the Company's general meeting on 23 February 2022.

14.7. Options and financial instruments

Currently, the capital structure of the PetroNor Australia includes only its ordinary Shares and 1,176,070 unlisted options expiring 31 May 2022 with exercise price of NOK 7.75/share. The Company previously had 213,400 additional outstanding and unlisted share options, which lapsed unexercised without compensation to the holders on 11 January 2022.

14.8. Shareholder rights

The Company has one class of Shares on issue, and in accordance with the Norwegian Public Limited Liability Companies Act, all Shares in that class provide equal rights in the Company. Each of the Company's Shares carries one vote. The rights attaching to the Shares are described in Section 14.9 "The articles of association and certain aspects of Norwegian law".

14.9. The articles of association and certain aspects of Norwegian law

14.9.1. The Articles of Association

The Company's Articles of Association are set out in Appendix A to this Prospectus. Below is a summary of certain of the provisions of the Articles of Association.

Company name

Pursuant to section 1 of the Articles of Association, the Company's name is PetroNor E&P ASA, a public limited liability company.

Objective of the Company

Pursuant to section 3 of the Articles of Association, the objective of the Company is to invest in companies and entities involved in the energy business and oil and gas industry worldwide as well as investment activities and other related activities.

Registered office

Pursuant to section 2 of the Articles of Association, the Company's registered office is in the municipality of Oslo, Norway.

Share capital and nominal value

Pursuant to section 4 of the Articles of Association, the Company's share capital is NOK 1,326,991.006 divided into 1,326,991,006 shares, each with a nominal value of NOK 0.001.

Board of Directors

Pursuant to section 5 of the Articles of Association, the Company's Board of Directors shall consist of up to 7 members, elected by the Company's General Meeting.

Restrictions on transfer of Shares

The Articles of Association do not provide for any restrictions on the transfer of Shares, or a right of first refusal for the Company's shareholders. Share transfers are not subject to approval by the Board of Directors.

Change of control

There are no provisions in the Articles of Association that would have an effect of delaying, deferring or preventing a change in control of the Company.

General meetings

Pursuant to section 7 of the Articles of Association, the annual general meeting shall consider and decide the following matters:

1. Approval of the annual accounts and report.

2. Use of profits or coverage of losses in accordance with the approved balance sheet, as well as distribution of dividends.

3. Election of board of directors.

4. Approval of the statement from the board of directors regarding salary and other remuneration to the executive management.

5. Any other matters which pursuant to law or the Articles of Association pertain to the general meeting.

The right to participate and vote at general meetings of the company can only be exercised for shares which have been acquired and registered in the shareholders register in the shareholders on the fifth business day prior to the general meeting.

Shareholders who intend to attend a general meeting of the company shall give the company written notice of their intention within a time limit given in the notice of the general meeting, which cannot expire earlier than five days before the general meeting. Shareholders, who have failed to give such notice within the time limit, can be denied admission.

When documents pertaining to matters which shall be handled at a general meeting have been made available for the shareholders on the company's website, the statutory requirement that the documents shall be distributed to the shareholders, does not apply. This is also applicable to documents which according to statutory law shall be included in or attached to the notice of the general meeting. A shareholder may nonetheless demand to be sent such documents.

The Board of Directors may in connection with notices of general meetings determine that shareholders shall be able to cast their votes in writing, including through use of electronic communication, in a period prior to the general meeting.

14.9.2. Certain aspects of Norwegian corporate law

General meetings

Through the general meeting, shareholders exercise supreme authority in a Norwegian company. In accordance with Norwegian law, the annual general meeting of shareholders is required to be held on or prior to 30 June of each year. Norwegian law requires that written notice of annual general meetings setting forth the time of, the venue for and the agenda of the meeting be sent to all shareholders with a known address no later than 21 days before the annual general meeting of a Norwegian public limited liability company listed on a stock exchange or a regulated market shall be held, unless the articles of association stipulate a longer deadline, which is not currently the case for the Company.

A shareholder may vote at the general meeting either in person or by proxy appointed at their own discretion. All of the Company's shareholders who are registered in the register of shareholders maintained with the VPS as of the date of the general meeting, or who have otherwise reported and documented ownership to Shares, are entitled to participate at general meetings.

Apart from the annual general meeting, extraordinary general meetings of shareholders may be held if the Board of Directors considers it necessary. An extraordinary general meeting of shareholders must also be convened if, in order to discuss a specified matter, the auditor or shareholders representing at least 5% of the share capital demands this in writing. The requirements for notice and admission to the annual general meeting also apply to extraordinary general meetings. However, the annual general meeting of a Norwegian public limited liability company may with a majority of at least two-thirds of the aggregate number of votes cast, as well as at least two-thirds of the share capital represented at a general meeting resolve that extraordinary general meetings may be convened with a 14 days' notice period until the next annual general meeting, provided that the Company has procedures in place allowing shareholders to vote electronically.

Voting rights – amendments to the Articles of Association

Each of the Company's shares carries one vote. In general, decisions that shareholders are entitled to make under Norwegian law or the Articles of Association may be made by a simple majority of the votes cast. In the case of elections or appointments, the person(s) who receive(s) the greatest number of votes cast are elected. However, as required under Norwegian law, certain decisions, including resolutions to waive preferential rights to subscribe in connection with any share issue in the Company, to approve a merger or demerger of the Company, to amend the Articles of Association, to authorize an increase or reduction in the share capital, to authorize an issuance of convertible loans or warrants by the Company or to authorize the Board of Directors to purchase Shares and hold them as treasury shares or to dissolve the Company, must receive the approval of at least two-thirds of the aggregate number of votes cast as well as at least two-thirds of the share capital represented at a general meeting. Norwegian law further requires that certain decisions, which have the effect of substantially altering the rights and preferences of any shares or class of shares, receive the approval by the holders of such shares or class of shares as well as the majority required for amending the Articles of Association.

Decisions that (i) would reduce the rights of some or all of the Company's shareholders in respect of dividend payments or other rights to assets or (ii) restrict the transferability of the Shares, require that at least 90% of the share capital represented at the general meeting in question vote in favour of the resolution, as well as the majority required for amending the Articles of Association.

In general, only a shareholder registered in the VPS is entitled to vote for such Shares. Beneficial owners of the Shares that are registered in the name of a nominee are generally not entitled to vote under Norwegian law, nor is any person who is designated in the VPS register as the holder of such Shares as nominees. Investors should note that there are varying opinions as to the interpretation of the right to vote on nominee registered shares. In the Company's view, a nominee may not meet or vote for Shares registered on a nominee account (NOM-account). A shareholder must, in order to be eligible to register, meet and vote for such Shares at the general meeting, transfer the Shares from such NOM-account to an account in the shareholder's name. Such registration must appear from a transcript from the VPS at the latest at the date of the general meeting.

There are no quorum requirements that apply to the general meetings.

Additional issuances and preferential rights

If the Company issues any new Shares, including bonus share issues, the Articles of Association must be amended, which requires the same vote as other amendments to the Articles of Association. In addition, under Norwegian law, the Company's shareholders have a preferential right to subscribe for new Shares issued by the Company. Preferential rights may be derogated from by resolution in a general meeting passed by the same vote required to amend the Articles of Association. A derogation of the shareholders' preferential rights in respect of bonus issues requires the approval of all outstanding Shares.

The general meeting may, by the same vote as is required for amending the Articles of Association, authorize the Board of Directors to issue new Shares, and to derogate from the preferential rights of shareholders in connection with such issuances. Such authorization may be effective for a maximum of two years, and the nominal value of the Shares to be issued may not exceed 50% of the registered nominal share capital when the authorization is registered with the Norwegian Register of Business Enterprises.

Under Norwegian law, the Company may increase its share capital by a bonus share issue, subject to approval by the Company's shareholders, by transfer from the Company's distributable equity or from the Company's share premium reserve and thus the share capital increase does not require any payment of a subscription price by the shareholders. Any bonus issues may be affected either by issuing new shares to the Company's existing shareholders or by increasing the nominal value of the Company's outstanding Shares.

Issuance of new Shares to shareholders who are citizens or residents of the United States upon the exercise of preferential rights may require the Company to file a registration statement in the United States under United States securities laws. Should the Company in such a situation decide not to file a registration statement, the Company's U.S. shareholders may not be able to exercise their preferential rights. If a U.S. shareholder is ineligible to participate in a rights offering, such shareholder would not receive the rights at all and the rights would be sold on the shareholder's behalf by the Company.

Minority rights

Norwegian law sets forth a number of protections for minority shareholders of the Company, including but not limited to those described in this paragraph and the description of general meetings as set out above. Any of the Company's shareholders may petition Norwegian courts to have a decision of the Board of Directors or the Company's shareholders made at the general meeting declared invalid on the grounds that it unreasonably favors certain shareholders or third parties to the detriment of other shareholders or the Company itself. The Company's shareholders may also petition the courts to dissolve the Company as a result of such decisions to the extent particularly strong reasons are considered by the court to make necessary dissolution of the Company.

Minority shareholders holding 5% or more of the Company's share capital have a right to demand in writing that the Board of Directors convene an extraordinary general meeting to discuss or resolve specific matters. In addition, any of the Company's shareholders may in writing demand that the Company place an item on the agenda for any general meeting as long as the Company is notified in time for such item to be included in the notice of the meeting. If the notice has been issued when such a written demand is presented, a renewed notice must be issued if the deadline for issuing notice of the general meeting has not expired.

Rights of redemption and repurchase of Shares

The share capital of the Company may be reduced by reducing the nominal value of the Shares or by cancelling Shares. Such a decision requires the approval of at least two-thirds of the aggregate number of votes cast and at least two-thirds of the share capital represented at a general meeting. Redemption of individual Shares requires the consent of the holders of the Shares to be redeemed.

The Company may purchase its own Shares provided that the Board of Directors has been granted an authorization to do so by a general meeting with the approval of at least two-thirds of the aggregate number of votes cast and at least two-thirds of the share capital represented at the meeting. The aggregate nominal value of treasury shares so acquired, and held by the Company must not exceed 10% of the Company's share capital, and treasury shares may only be acquired if the Company's distributable equity, according to the latest adopted balance sheet, exceeds the consideration to be paid for the shares. The authorisation by the General Meeting of the Company cannot be granted for a period exceeding 24 months.

Shareholder vote on certain reorganisations

A decision of the Company's shareholders to merge with another company or to demerge requires a resolution by the general meeting of the shareholders passed by at least two-thirds of the aggregate votes cast and at least two-thirds of the share capital represented at the general meeting. A merger plan, or demerger plan signed by the Board of Directors along with certain other required documentation, would have to be sent to all the Company's shareholders, or if the Articles of Association stipulate that, made available to the shareholders on the Company's website, at least one month prior to the general meeting to pass upon the matter.

Liability of board members

Members of the Board of Directors owe a fiduciary duty to the Company and its shareholders. Such fiduciary duty requires that the Board Members act in the best interests of the Company when exercising their functions and exercise a general duty of loyalty and care towards the Company. Their principal task is to safeguard the interests of the Company.

Members of the Board of Directors may each be held liable for any damage they negligently or wilfully cause the Company. Norwegian law permits the general meeting to discharge any such person from liability, but such discharge is not binding on the Company if substantially correct and complete information was not provided at the general meeting of the Company's shareholders passing upon the matter. If a resolution to discharge the Board Members from liability or not to pursue claims against such a person has been passed by a general meeting with a smaller majority than that required to amend the Articles of Association, shareholders representing more than 10% of the share capital or, if there are more than 100 shareholders, more than 10% of the shareholders may pursue the claim on the Company's behalf and in its name. The cost of any such action is not the Company's responsibility but can be recovered from any proceeds the Company receives as a result of the action. If the decision to discharge any of the Board Members from liability or not to pursue claims against the Board Members is made by such a majority as is necessary to amend the Articles of Association, the minority shareholders of the Company cannot pursue such claim in the Company's name.

Indemnification of board members

Neither Norwegian law nor the Articles of Association contains any provision concerning indemnification by the Company of the Board of Directors. The Company is permitted to purchase insurance for its Board Members against certain liabilities that they may incur in their capacity as such.

Distribution of assets on liquidation

Under Norwegian law, the Company may be wound-up by a resolution of the Company's shareholders at the general meeting passed by at least two-thirds of the aggregate votes cast and at least two-thirds of the share capital represented at the meeting. In the event of liquidation, the Shares rank equally in the event of a return on capital.

14.10. Shareholder agreements

The Company is not aware of any shareholders' agreements related to the Shares which will be in force upon Listing.

15. SECURITIES TRADING IN NORWAY

15.1. Introduction

Oslo Børs was established in 1819 and is the principal market in which shares, bonds and other financial instruments are traded in Norway. Oslo Børs was in 2019 acquired by Euronext N.V.

15.2. Trading and settlement

Trading of equities on the Oslo Stock Exchange is carried out in the electronic trading system Optiq®. This trading system is in use by all markets operated by Euronext.

Official trading on the Oslo Stock Exchange takes place between 09:00 hours (CET/CEST) and 16:20 hours (CET/CEST) each trading day, with pre-trade period between 07:15 hours (CET/CEST) and 09:00 hours (CET/CEST), a closing auction from 16:20 hours (CET/CEST) to 16:25 hours (CET/CEST) and a trading at last period from 16:25 hours (CET/CEST) to 16:30 hours (CET/CEST). Reporting of Off-Book On Exchange trades can be done from 07:15 hours (CET/CEST) to 18:00 hours (CET/CEST).

The settlement period for trading on the Oslo Stock Exchange is two trading days (T+2). This means that securities will be settled on the investor's account in the VPS two days after the transaction, and that the seller will receive payment after two days.

The Oslo Stock Exchange offers an interoperability model for clearing and counterparty services for equity trading through LCH Limited, EuroCCP and Six X-Clear.

Investment services in Norway may only be provided by Norwegian investment firms holding a license under the Norwegian Securities Trading Act, branches of investment firms from an EEA member state or investment firms from outside the EEA that have been licensed to operate in Norway. Investment firms in an EEA member state may also provide cross-border investment services into Norway.

It is possible for investment firms to undertake market-making activities in shares listed in Norway if they have a license to this effect under the Norwegian Securities Trading Act, or in the case of investment firms in an EEA member state, a license to carry out market-making activities in their home jurisdiction. Such market-making activities will be governed by the regulations of the Norwegian Securities Trading Act relating to brokers' trading for their own account. However, such market-making activities do not as such require notification to the Norwegian FSA or the Oslo Stock Exchange except for the general obligation of investment firms that are members of the Oslo Stock Exchange to report all trades in stock exchange listed securities.

15.3. Information, control and surveillance

Under Norwegian law, Oslo Børs is required to perform a number of surveillance and control functions. The Surveillance and Corporate Control unit of Oslo Børs monitors all market activity on a continuous basis. Market surveillance systems are largely automated, promptly warning department personnel of abnormal market developments.

The Norwegian FSA controls the issuance of securities in both the equity and bond markets in Norway and evaluates whether the issuance documentation contains the required information and whether it would otherwise be unlawful to carry out the issuance.

Under Norwegian law, a company that is listed on a Norwegian regulated market, or has applied for listing on such market, must promptly release any inside information directly concerning the company (i.e. precise information about financial instruments, the issuer thereof or other matters which are likely to have a significant effect on the price of the relevant financial instruments or related financial instruments, and which are not publicly available or commonly known in the market). A company may, however, delay the release of such information in order not to prejudice its legitimate interests, provided that it is able to ensure the confidentiality of the information and that the delayed release would not be likely to mislead the public. Oslo Børs may levy fines on companies violating these requirements.

15.4. The VPS and transfer of shares

The Company's principal share register is operated through the VPS. The VPS is the Norwegian paperless centralized securities register. It is a computerized book-keeping system in which the ownership of, and all transactions relating to, Norwegian listed shares must be recorded.

All transactions relating to securities registered with the VPS are made through computerized book entries. No physical share certificates are, or may be, issued. The VPS confirms each entry by sending a transcript to the registered shareholder irrespective of any beneficial ownership. To give effect to such entries, the individual shareholder must establish a share account with a Norwegian account agent. Norwegian banks, Norges Bank (being the Central Bank of Norway'), authorized securities brokers in Norway and Norwegian branches of credit institutions established within the EEA are allowed to act as account agents.

As a matter of Norwegian law, the entry of a transaction in the VPS is prima facie evidence in determining the legal rights of parties as against the issuing company or any third party claiming an interest in the given security. A transferee or assignee of shares may not exercise the rights of a shareholder with respect to such shares unless such transferee or assignee has registered such shareholding or has reported and shown evidence of such share acquisition, and the acquisition is not prevented by law, the Company's Articles of Association or otherwise.

The VPS is liable for any loss suffered as a result of faulty registration or an amendment to, or deletion of, rights in respect of registered securities unless the error is caused by matters outside the VPS' control which the VPS could not reasonably be expected to avoid or overcome the consequences of. Damages payable by the VPS may, however, be reduced in the event of contributory negligence by the aggrieved party.

The VPS must provide information to the Norwegian FSA on an ongoing basis, as well as any information that the Norwegian FSA requests. Further, Norwegian tax authorities may require certain information from the VPS regarding any individual's holdings of securities, including information about dividends and interest payments.

15.5. Shareholder register – Norwegian law

Under Norwegian law, shares are registered in the name of the beneficial owner of the shares. As a general rule, there are no arrangements for nominee registration and Norwegian shareholders are not allowed to register their shares in VPS through a nominee. However, foreign shareholders may register their shares in the VPS in the name of a nominee (bank or other nominee) approved by the Norwegian FSA. An approved and registered nominee has a duty to provide information on demand about beneficial shareholders to the company and to the Norwegian authorities. In case of registration by nominees, the registration in the VPS must show that the registered owner is a nominee. A registered nominee has the right to receive dividends and other distributions, but cannot vote in general meetings on behalf of the beneficial owners.

15.6. Foreign investment in shares listed in Norway

Foreign investors may trade shares listed on Oslo Børs through any broker that is a member of Oslo Børs, whether Norwegian or foreign.

15.7. Disclosure obligations

If a person's, entity's or consolidated group's proportion of the total issued shares and/or rights to shares in a company listed on a regulated market in Norway (with Norway as its home state, which will be the case for the Company) reaches, exceeds or falls below the respective thresholds of 5%, 10%, 15%, 20%, 25%, 1/3, 50%, 2/3 or 90% of the share capital or the voting rights of that company, the person, entity or group in question has an obligation under the Norwegian Securities Trading Act to notify Oslo Børs and the issuer immediately. The same applies if the disclosure thresholds are passed due to other circumstances, such as a change in the company's share capital.

15.8. Insider trading

According to Norwegian law, implementing MAR, subscription for, purchase, sale or exchange of financial instruments that are listed, or subject to the application for listing, on a Norwegian regulated market, or incitement to such dispositions, must not be undertaken by anyone who has inside information, as defined in MAR art. 7. The same applies to the entry into, purchase, sale or exchange of options or futures/forward contracts or equivalent rights whose value is connected to such financial instruments or incitement to such dispositions.

15.9. Mandatory offer requirement

The Norwegian Securities Trading Act requires any person, entity or consolidated group that becomes the owner of shares representing more than one-third of the voting rights of a company listed on a Norwegian regulated market (with the exception of certain foreign companies) to, within four weeks, make an unconditional general offer for the purchase of the remaining shares in that company. A mandatory offer obligation may also be triggered where a party acquires the right to become the owner of shares that, together with the party's own shareholding, represent more than one-third of the voting rights in the company and Oslo Børs decides that this is regarded as an effective acquisition of the shares in question.

The mandatory offer obligation ceases to apply if the person, entity or consolidated group sells the portion of the shares that exceeds the relevant threshold within four weeks of the date on which the mandatory offer obligation was triggered (or provided that the person, entity or consolidated group has not already stated that it will proceed with the making of a mandatory offer).

When a mandatory offer obligation is triggered, the person subject to the obligation is required to immediately notify Oslo Børs and the company in question accordingly. The notification is required to state whether an offer will be made to acquire the remaining shares in the company or whether a sale will take place. As a rule, a notification to the effect that an offer will be made cannot be retracted. The offer and the offer document required are subject to approval by Oslo Børs before the offer is submitted to the shareholders or made public.

The offer price per share must be at least as high as the highest price paid or agreed by the offeror for the shares in the six-month period prior to the date the threshold was exceeded. If the acquirer acquires or agrees to acquire additional shares at a higher price prior to the expiration of the mandatory offer period, the acquirer is obliged to restate its offer at such higher price. A mandatory offer must be in cash or contain a cash alternative at least equivalent to any other consideration offered. The settlement must be guaranteed by a financial institution authorised to provide such guarantees in Norway.

In case of failure to make a mandatory offer or to sell the portion of the shares that exceeds the relevant threshold within four weeks, Oslo Børs may force the acquirer to sell the shares exceeding the threshold by public auction. Moreover, a shareholder who fails to make an offer may not, as long as the mandatory offer obligation remains in force, exercise rights in the company, such as voting in a general meeting, without the consent of a majority of the remaining shareholders. The shareholder may, however, exercise his/her/its rights to dividends and pre-emption rights in the event of a share capital increase. If the shareholder neglects his/her/its duty to make a mandatory offer, Oslo Børs may impose a cumulative daily fine that runs until the circumstance has been rectified.

Any person, entity or consolidated group that owns shares representing more than one-third of the votes in a company listed on a Norwegian regulated market (with the exception of certain foreign companies) is obliged to make an offer to purchase the remaining shares of the company (repeated offer obligation) if the person, entity or consolidated group through acquisition becomes the owner of shares representing 40%, or more of the votes in the company. The same applies if the person, entity or consolidated group through acquisition becomes the owner of shares representing 50% or more of the votes in the company. The mandatory offer obligation ceases to apply if the person, entity or consolidated group sells the portion of the shares which exceeds the relevant threshold within four weeks of the date on which the mandatory offer obligation was triggered (provided that the person, entity or consolidated group has not already stated that it will proceed with the making of a mandatory offer).

Any person, entity or consolidated group that has passed any of the above mentioned thresholds in such a way as not to trigger the mandatory bid obligation, and has therefore not previously made an offer for the remaining shares in the company in accordance with the mandatory offer rules is, as a main rule, obliged to make a mandatory offer in the event of a subsequent acquisition of shares in the company.

15.10. Compulsory acquisition

Pursuant to the Norwegian Public Limited Liability Companies Act and the Norwegian Securities Trading Act, a shareholder who, directly or through subsidiaries, acquires shares representing 90% or more of the total number of issued shares in a Norwegian public limited company, as well as 90% or more of the total voting rights, has a right, and each remaining minority shareholder of the company has a right to require such majority shareholder, to effect a compulsory acquisition for cash of the shares not already owned by such majority shareholder. Through such compulsory acquisition the majority shareholder becomes the owner of the remaining shares with immediate effect.

If a shareholder acquires shares representing more than 90% of the total number of issued shares, as well as more than 90% of the total voting rights, through a voluntary offer in accordance with the Securities Trading Act, a compulsory acquisition can, subject to the following conditions, be carried out without such shareholder being obliged to make a mandatory offer: (i) the compulsory acquisition is commenced no later than four weeks after the acquisition of shares through the voluntary offer, (ii) the price offered per share is equal to or higher than what the offer price would have been in a mandatory offer, and (iii) the settlement is guaranteed by a financial institution authorized to provide such guarantees in Norway.

A majority shareholder who effects a compulsory acquisition is required to offer the minority shareholders a specific price per share, the determination of which is at the discretion of the majority shareholder.

Should any minority shareholder not accept the offered price, such minority shareholder may, within a specified deadline of not less than two months, request that the price be set by a Norwegian court. The cost of such court procedure will, as a general rule, be the responsibility of the majority shareholder, and the relevant court will have full discretion in determining the consideration to be paid to the minority shareholder as a result of the compulsory acquisition. However, where the offeror, after making a mandatory or voluntary offer, has acquired more than 90% of the voting shares of a company and a corresponding proportion of the votes that can be cast at the general meeting, and the offeror pursuant to Section 4-25 of the Norwegian Public Limited Liability Companies Act completes a compulsory acquisition of the remaining shares within three months after the expiry of the offer period, it follows from the Norwegian Securities Trading Act that the redemption price shall be determined on the basis of the offer price for the mandatory/voluntary offer unless specific reasons indicate another price.

Absent a request for a Norwegian court to set the price or any other objection to the price being offered, the minority shareholders would be deemed to have accepted the offered price after the expiry of the specified deadline.

15.11. Foreign exchange controls

There are currently no foreign exchange control restrictions in Norway that would potentially restrict the payment of dividends to a shareholder outside Norway, and there are currently no restrictions that would affect the right of shareholders of a company that has its shares registered with the VPS who are not residents in Norway to dispose of their shares and receive the proceeds from a disposal outside Norway. There is no maximum transferable amount either to or from Norway, although transferring banks are required to submit reports on foreign currency exchange transactions into and out of Norway into a central data register maintained by the Norwegian customs and excise authorities. The Norwegian police, tax authorities, customs and excise authorities, the National Insurance Administration and the Norwegian FSA have electronic access to the data in this register.

16. TAXATION

Set out below is a summary of certain Norwegian tax matters related to an investment in the Company. The summary regarding Norwegian taxation is based on the laws in force in Norway as of the date of this Prospectus, which may be subject to any changes in law occurring after such date. Such changes could possibly be made on a retrospective basis.

The following summary does not purport to be a comprehensive description of all the tax considerations that may be relevant to a decision to purchase, own or dispose of the shares in the Company. Shareholders who wish to clarify their own tax situation should consult with and rely upon their own tax advisers. Shareholders resident in jurisdictions other than Norway and shareholders who cease to be resident in Norway for tax purposes (due to domestic tax law or tax treaty) should specifically consult with and rely upon their own tax advisers with respect to the tax position in their country of residence and the tax consequences related to ceasing to be resident in Norway for tax purposes. The statements in the summary only apply to shareholders who are beneficial owners of the Shares.

Please note that for the purpose of the summary below, a reference to a Norwegian or non-Norwegian shareholder refers to the tax residency rather than the nationality of the shareholder.

16.1. Norwegian taxation

16.1.1. Taxation of dividends

Norwegian Personal Shareholders

Dividends distributed to shareholders who are individuals residing in Norway for tax purposes ("**Norwegian Personal Shareholders**") are taxable in Norway for such shareholders currently at an effective tax rate of 31.68% (for 2021) to the extent the dividend exceeds a tax-free allowance; i.e. dividends received, less the tax-free allowance, shall be multiplied by 1.44 which are then included as ordinary income taxable at a flat rate of 22%, increasing the effective tax rate on dividends received by Norwegian Personal Shareholders to 31.68%. If the parliament approves the new government's proposal for the state budget, the new adjustment factor will be 1.6, which will give an effective tax rate of 35,2% from 2022.

The allowance is calculated on a share-by-share basis. The allowance for each share is equal to the cost price of the share multiplied by a determined risk-free interest rate based on the effective rate of interest on treasury bills (Nw.: statskasseveksler) with three months maturity plus 0.5 percentage points, after-tax. The allowance is calculated for each calendar year, and is allocated solely to Norwegian Personal Shareholders holding shares at the expiration of the relevant calendar year.

Norwegian Personal Shareholders who transfer shares will thus not be entitled to deduct any calculated allowance related to the year of transfer. Any part of the calculated allowance one year exceeding the dividend distributed on the share ("excess allowance") may be carried forward and set off against future dividends received on, or gains upon realization, of the same share (but may not be set off against taxable dividends or capital gains on other Shares). Furthermore, excess allowance can be added to the cost price of the share and included as the basis for calculating the tax-free allowance on the same share the following year.

Norwegian Personal Shareholders may hold the shares through a Norwegian share saving account (NW.: aksjesparekonto). Dividends received on shares held through a share saving account will not be taxed with immediate effect. Instead, withdrawal of funds from the share saving account exceeding the paid in deposit will be regarded as taxable income, regardless of whether the funds are derived from gains or dividends related to the shares held in the account. Such income will be taxed with an effective tax rate of 31.68% (expected to be 35,2% from 2022), cf. above. Norwegian Personal Shareholders will still be entitled to a calculated tax-free allowance. Please refer to Section 16.1.2 "Taxation of capital gains on realisation of shares Norwegian Personal Shareholders" for further information in respect of Norwegian share saving accounts.

Norwegian Corporate Shareholders

Dividends distributed to shareholders who are limited liability companies (and certain similar entities) domiciled in Norway for tax purposes ("**Norwegian Corporate Shareholders**"), are effectively taxed at a rate of currently 0.66% (3% of dividend income from such shares is included in the calculation of ordinary income for Norwegian Corporate Shareholders and ordinary income is subject to tax at a flat rate of currently 22% for 2021). For Norwegian Corporate Shareholders that are considered to be "Financial Institutions" under the Norwegian financial activity tax, the effective tax rate of taxation of dividends is 0.75%.

Non-Norwegian Personal Shareholders

Dividends distributed to shareholders who are individuals not residing in Norway for tax purposes ("**Non-Norwegian Personal Shareholders**"), are as a general rule subject to withholding tax at a rate of 25%. The withholding tax rate of 25% is normally reduced through tax treaties between Norway and the country in which the shareholder is resident. The withholding obligation lies with the company distributing the dividends and the Company assumes this obligation.

Non-Norwegian Personal Shareholders residing within the EEA for tax purposes may apply individually to Norwegian tax authorities for a refund of an amount corresponding to the calculated tax-free allowance on each individual share (please see "Taxation of dividends – Norwegian Personal Shareholders" above). However, the deduction for the tax-free allowance does not apply in the event that the withholding tax rate, pursuant to an applicable tax treaty, leads to lower taxation of the dividends than the withholding tax rate of 25% less the tax-free allowance.

If a Non-Norwegian Personal Shareholder is carrying on business activities in Norway and the shares are effectively connected with such activities, the shareholder will be subject to the same taxation of dividends as a Norwegian Personal Shareholder, as described above.

Non-Norwegian Personal Shareholders who have suffered a higher withholding tax than set out in an applicable tax treaty may apply to the Norwegian tax authorities for a refund of the excess withholding tax deducted.

All Non-Norwegian Personal Shareholders must document their entitlement to a reduced withholding tax rate by obtaining a certificate of residence issued by the tax authorities in the shareholder's country of residence, confirming that the shareholder is resident in that state. The documentation must be provided to either the nominee or the account operator (VPS) and cannot be older than three years.

Non-Norwegian Personal Shareholders should consult their own advisers regarding the availability of treaty benefits in respect of dividend payments, including the possibility of effectively claiming a refund of withholding tax.

Non-Norwegian Personal Shareholders resident in the EEA for tax purposes may hold their shares through a Norwegian share saving account. Dividends received on and gain derived upon the realization of shares held through a share saving account by a Non-Norwegian Personal Shareholder resident in the EEA will not be taxed with immediate effect. Instead, withdrawal of funds from the share saving account exceeding the Non-Norwegian Personal Shareholder's paid in deposit, will be subject to withholding tax rate at a rate of 25% (unless reduced pursuant to an applicable tax treaty). Capital gains realized upon realization of shares held through the share saving account will be regarded as paid in deposits, which may be withdrawn without taxation. Losses will correspondingly be deducted from the paid-in deposit, reducing the amount which can be withdrawn without withholding tax.

The obligation to deduct and report withholding tax on shares held through a saving account, ref. above, lies with the account operator.

Non-Norwegian Corporate Shareholders

Dividends distributed to shareholders who are limited liability companies (and certain other entities) domiciled outside of Norway for tax purposes ("**Non-Norwegian Corporate Shareholders**"), are as a general rule subject to withholding tax at a rate of 25%. The withholding tax rate of 25% is normally reduced through tax treaties between Norway and the country in which the shareholder is resident.

Dividends distributed to Non-Norwegian Corporate Shareholders domiciled within the EEA for tax purposes are exempt from Norwegian withholding tax provided that the shareholder is the beneficial owner of the shares and that the shareholder is genuinely established and performs genuine economic business activities within the relevant EEA jurisdiction.

If a Non-Norwegian Corporate Shareholder is carrying on business activities in Norway and the shares are effectively connected with such activities, the shareholder will be subject to the same taxation of dividends as a Norwegian Corporate Shareholder, as described above.

Non-Norwegian Corporate Shareholders who have suffered a higher withholding tax than set out in an applicable tax treaty may apply to the Norwegian tax authorities for a refund of the excess withholding tax deducted. The same will apply to Non-Norwegian Corporate Shareholders who have suffered withholding tax although qualifying for the Norwegian participation exemption.

All Non-Norwegian Corporate Shareholders must document their entitlement to a reduced withholding tax rate by either (i) presenting an approved withholding tax refund application or (ii) presenting an approval from the Norwegian tax authorities confirming that the recipient is entitled to a reduced withholding tax rate. In addition, a certificate of residence issued by the tax authorities in the shareholder's country of residence, confirming that the shareholder is resident in that state, must be obtained. Such documentation must be provided to either the nominee or the account operator (VPS).

In order for a Non-Norwegian Corporate Shareholder resident in the EEA to be exempt from withholding tax, the company must provide all documentation mentioned above, as well as a declaration stating that the circumstances entitling the company to the exemption have not changed since the documentation was issued.

Nominee registered shares will be subject to withholding tax at a rate of 25% unless the nominee has obtained approval from the Norwegian Tax Directorate for the dividend to be subject to a lower withholding tax rate. To obtain such approval the nominee is required to file a summary to the tax authorities including all beneficial owners that are subject to withholding tax at a reduced rate.

The withholding obligation in respect of dividends distributed to Non-Norwegian Corporate Shareholders and on nominee registered shares lies with the company distributing the dividends and the Company assumes this obligation.

Non-Norwegian Corporate Shareholders should consult their own advisers regarding the availability of treaty benefits in respect of dividend payments, including the possibility of effectively claiming a refund of withholding tax.

16.1.2. Taxation of capital gains on realisation of shares

Norwegian Personal Shareholders

Sale, redemption, or other disposals of shares is considered a realization for Norwegian tax purposes. A capital gain or loss generated by a Norwegian Personal Shareholder through disposal of shares is taxable or tax-deductible in Norway. The effective tax rate on gain or loss related to shares realized by Norwegian Personal Shareholders is currently 31.68 % (expected to be 35.2% from 2022); i.e. capital gains (less the tax-free allowance) and losses shall be multiplied by 1.44 (expected to be 1.6 from 2022) which are then included in or deducted from the Norwegian Personal Shareholder's ordinary income in the year of disposal. Ordinary income is taxable at a flat rate of 22% (2021), increasing the effective tax rate on gains/losses realized by Norwegian Personal Shareholders to 31.68% (expected to be 35.2% from 2022).

The gain is subject to tax and the loss is tax-deductible irrespective of the duration of the ownership and the number of shares disposed of.

The taxable gain/deductible loss is calculated per share as the difference between the consideration for the share and the Norwegian Personal Shareholder's cost price of the share, including costs incurred in relation to the acquisition or realization of the share. From this capital gain, Norwegian Personal Shareholders are entitled to deduct a calculated allowance provided that such allowance has not already been used to reduce taxable dividend income. Please refer to Section 16.1.1 "Taxation of dividends" above for a description of the calculation of the allowance. The allowance may only be deducted in order to reduce a taxable gain, and cannot increase or produce a deductible loss, i.e. any unused allowance exceeding the capital gain upon the realization of a share will be annulled. Unused allowance may not be set off against gains from realisation of other shares.

If the Norwegian Personal Shareholder owns shares acquired at different points in time, the shares that were acquired first will be regarded as the first to be disposed of, on a first-in-first-out basis.

Special rules apply for Norwegian Personal Shareholders that cease to be tax-resident in Norway.

Gains derived upon the realization of Shares held through a share saving account (Nw: aksjesparekonto) will be exempt from Norwegian taxation and losses will not be tax-deductible. Instead, withdrawal of funds from the share saving account exceeding the Norwegian Personal Shareholder's paid in deposit, will be regarded as taxable income, subject to tax at an effective tax rate of 31.68% (expected to be 35.2% from 2022). Norwegian Personal Shareholders will be entitled to a calculated tax-free allowance provided that such allowance has not already been used to reduce taxable dividend income (please see "Taxation of dividends – Norwegian Personal Shareholders" above). The tax-free allowance is calculated based on the lowest paid-in deposit in the account during the income year, plus any unused tax-free allowance from previous years. The tax-free allowance can only be deducted in order to reduce taxable income, and cannot increase or produce a deductible loss. Any excess allowance may be carried forward and set off against future withdrawals from the account or future dividends received on shares held through the account.

Norwegian Personal Shareholders holding shares through more than one share savings account may transfer their shares or securities between the share saving accounts without incurring Norwegian taxation.

Norwegian Corporate Shareholders

Norwegian Corporate Shareholders are exempt from tax on capital gains derived from the realization of shares qualifying for participation exemption, including shares in the Company. Losses upon the realization and costs incurred in connection with the purchase and realization of such shares are not deductible for tax purposes.

Special rules apply for Norwegian Corporate Shareholders that cease to be tax-resident in Norway.

Non-Norwegian Personal Shareholders

Gains from the sale or other disposal of shares by a Non-Norwegian Personal Shareholder will not be subject to taxation in Norway unless the Non-Norwegian Personal Shareholder holds the shares in connection with business activities carried out or managed from Norway. Please refer to section 16.1.1 "Taxation of dividends Norwegian Personal Shareholders" above for a description of the availability of a Norwegian share saving account.

Non-Norwegian Corporate Shareholders

Capital gains derived by the sale or other realization of shares by Non-Norwegian Corporate Shareholders are not subject to taxation in Norway unless the shareholding is effectively connected with business activities carried out in or managed from Norway.

16.1.3. Net wealth tax

The value of shares is included in the basis for the computation of net wealth tax imposed on Norwegian Personal Shareholders. Currently, the marginal net wealth tax rate is 0.85% (expected to be 0.95% from 2022) of the value assessed. The value for assessment purposes for listed shares is equal to 55% (expected to be 65% from 2022) of the listed value as of 1 January in the year of assessment (i.e. the year following the relevant fiscal year). The value of debt allocated to the listed shares for Norwegian wealth tax purposes is reduced correspondingly (i.e. to 55%, expected to be 65% from 2022).

Norwegian Corporate Shareholders are not subject to net wealth tax.

Shareholders not resident in Norway for tax purposes (Personal and Corporate) are generally not subject to Norwegian net wealth tax. Non-Norwegian Personal Shareholders can, however, be taxable if the shareholding is effectively connected to the conduct of trade or business in Norway.

16.1.4. VAT and transfer taxes

No VAT, stamp, or similar duties are currently imposed in Norway on the transfer or issuance of shares.

16.1.5. Inheritance tax

A transfer of shares through inheritance or as a gift does not give rise to inheritance or gift tax in Norway.

17. ADDITIONAL INFORMATION

17.1. Independent auditor

The Company's current independent auditor is BDO AS, with business registration number 993 606 650, and registered business address Munkedamsveien 45A, N-0250 Oslo, Norway. BDO AS is member of The Norwegian Institute of Public Accountants (Nw.: Den Norske Revisorforening). BDO AS has been the Company's auditor since its inception.

The independent auditor for the previous ultimate parent company of the Group prior to the Redomiciliation, PetroNor Australia, is BDO Audit (WA) Pty Ltd, a member firm of BDO International Ltd, 38 Station Street, Subiaco, Western Australia 6008, being a Chartered Firm with the Institute of Chartered Accountants Australia. BDO Audit (WA) Pty Ltd has been the auditor for PetroNor Australia since 19 January 2017.

17.2. Advisors

Advokatfirmaet Schjødt AS (address: Ruseløkkveien 14-16, N-0251 Oslo, Norway) is acting as Norwegian legal counsel to the Company in connection with the Listing.

17.3. FSA approval

This Prospectus has been approved by the Norwegian FSA, as competent authority under Regulation (EU) 2017/1129. The Norwegian FSA only approves this Prospectus as meeting the standards of completeness, comprehensibility and consistency imposed by Regulation (EU) 2017/1129. Such approval should not be considered as an endorsement of the issuer or the securities that are the subject of this Prospectus. Investors should make their own assessment as to the suitability of investing in the securities.

17.4. Documents on display

Copies of the following documents will be available for inspection at the Company's offices at Frøyas gate 13, N-0273 Oslo, Norway, during normal business hours from Monday to Friday each week (except public holidays) for a period of twelve months from the date of this Prospectus:

- the Company's certificate of incorporation and Articles of Association;
- all reports, letters, and other documents, historical Financial Information, valuations and statements prepared by any expert at the Company's request any part of which is included or referred to in this Prospectus; and
- this Prospectus.

The documents are also available at the Company's website www.petronorep.com.

17.5. Incorporation by reference

The information incorporated by reference in this Prospectus should be read in connection with the cross reference table set out below. Except from this Section 17.5 "Incorporation by reference", no other information is incorporated by reference in this Prospectus.

Section in Prospectus	Reference	Reference document and web address
Section 4 and Section 10	The Company's audited interim report for the one-month period ended 1 October 2021, including an overview of the Company's accounting policy and explanatory notes and the auditor's report	PetroNor Norway Financial Statements: *https://sarepta.brreg.no/kunngjoring/regnskapsregisteret/mellombalanse/2021/02/59/10/2021025910.tif*
4 and 10	PetroNor Cypus' audited annual report for the 12 month period ended 2018, including an overview of the accounting policy and explanatory notes and the auditor's report	Annual report of PetroNor Cyprus for 2018: *https://petronorep.com/media/hctg2gzu/petronor-annual-report-2018.pdf*

18. DEFINITIONS AND GLOSSARY

In the Prospectus, the following defined terms have the following meanings:

AGC	Dome Flore area
AGR	AGR Petroleum Ressources AS
Aje Transaction	The transaction governed by the Panoro Agreement and the YFP Agreement.
AJVP	Agreement for Joint Venture Participation
Allocation Rights	The non-transferrable allocation rights granted to Eligible Shareholders
Anti-Money Laundering Legislation	The Norwegian Money Laundering Act of 1 June 2018 No. 23 and the Norwegian Money Laundering Regulations of 14 September 2018 No. 1324
APCL	African Petroleum Corporation Limited
APMs	Alternative Performance Measures
Articles of Association	The Company's articles of association as at the date of this Prospectus
ASX	Australian Securities Exchange
Australian Shares	The shares of Petronor Australia
Bcf of Gas	Billions of Cubic Feet of Gas
BDO	BDO Audit (WA) Pty Ltd, a member firm of BDO International Ltd, 38 Station Street, Subiaco, Western Australia 6008, being a Chartered Firm with the Institute of Chartered Accountants Australia
BEAC	Central African States Bank
Board or Board of Directors	The Board of Directors of the Company
Board Members	The members comprising the Board of Directors
Bopd or bopd	Oil of barrels produced per day
BP	BP Exploration Operating Company Limited
CEMAC	Economic and Monetary Community of Central African States
CEO	Chief Executive Officer
CGT	Capital gains tax
CIA Fact Book	The World Fact Book By The Central Intelligence Agency Of USA
CIMA	Inter-African Conference on Insurance Markets
Company	PetroNor E&P ASA
Conditional Consideration	Payment of an additional consideration of USD 0.10 per 1,000 cubic feet of the Aje Natural Gas Sales Volume by the Company to Panoro

Congo	Republic of Congo
Corporations Act	The Australian Corporations Act 2001 (Cth)
Corporate Governance Code	Norwegian Code of Practice for Corporate Governance
CoSec	Company Secretary
CPR	Competent Persons Report
DPR	Nigerian Department of Petroleum Resources
EEA	the European Economic Area
EHL	European Hydrocarbons Limited
EIA	Environmental Impact Assessment
EIIC	Emirates International Investment Company
EGASPIN	Environmental Guidelines and Standards for the Petroleum Industry in Nigeria
EGM	The extraordinary general meeting of the Company
EU Prospectus Regulation	Regulation (EU) 2017/1129 of the European Parliament and of the Council of 14 June 2017 on the prospectus to be published when securities are offered to the public or admitted to trading on a regulated market, and repealing Directive 2003/71/EC, as amended, and as implemented in Norway in accordance with Section 7-1 of the Norwegian Securities Trading Act
Euronext Expand	Oslo Euronext Expand, a regulated market operated by Oslo Børs ASA
FATA	Australian Foreign Acquisitions and Takeovers Act 1975
FEPA	formally Federal Environmental Protection Agency, now Federal Ministry of Environment of Nigeria
Financial Information	The Financial Statements, the Interim Financial Statements and the PetroNor Norway Financial Statements
Financial Statements	The Group's audited consolidated financial statements as of and for the year ended 31 December 2020, 2019 and 2018
FIRB	The Australian Foreign Investment Review Board
FIRS	Federal Inland Revenue Service of Nigeria
FMEnv	Federal Ministry of Environment of Nigeria
FMOE	Federal Ministry of Environment of Nigeria
FPSO	Floating production storage and offloading
FTEs	Full time employees
FX	Foreign exchange

GB Transaction	the purchase of the entity SPE Guinea Bissau
GHG	greenhouse gas
Global Iron	Global Iron Limited
GNPC	Gambia National Petroleum Company
GOR	Gas to oil ratio
Group or PetroNor	The Company together with its consolidated subsidiaries
Guinea-Bissau Transaction	The Company’s purchase of the entity SPE Guinea Bissau AB
HAH	Hemla Africa Holding AS
HEPCO	Hemla E&P Congo S.A.
ICPE	Installation Classified for Environmental protection
ICSID	International Centre for Settlement of Investment Disputes
IFRS	International Financial Reporting Standards
Interim Financial Statements	The Group’s interim financial statements as at and for the six-month period ended 30 June 2021
ISAs	International Standards on Auditing
Listing or Admission to Trading	The admission to trading of the Company's Shares
Local Content Act	Nigerian Oil and Gas Industry Content Development Act
Management	The Company's executive management
ME	Ministry of Energy of Gambia
Member State	Any member state of the EEA other than Norway
MGI	MGI International S.A.
MMbbl	Million barrels of oil equivalents
MMboe	Million units of barrels of oil equivalents
MMscfd	Million standard cubic feet per day of gas
MoPE	Ministry of Petroleum and Energy of Gambia
mTVDSS	Meters in True Vertical Depth Subsea
NSX	National Stock Exchange of Australia
NDDC	Niger Delta Development Commission
Non-Norwegian Corporate Shareholders	Shareholders who are limited liability companies (and certain other entities) domiciled outside of Norway for tax purposes

Non-Norwegian Personal Shareholders	Shareholders who are individuals not residing in Norway for tax purposes
NOR	NOR Energy AS
Norwegian Corporate Shareholders	Shareholders who are limited liability companies (and certain similar entities) domiciled in Norway for tax purposes
Norwegian FSA or NFSA	The Financial Supervisory Authority of Norway (Nw.: *Finanstilsynet*)
Norwegian Personal Shareholders	Shareholders who are individuals residing in Norway for tax purposes
Norwegian Securities Trading Act	The Norwegian Securities Trading Act of 29 June 2007 no. 75, as amended
OHADA	Organization for the Harmonization of Business Law in Africa
OML-113	Offshore Mining Lease no. 113
Order	The Financial Services and Markets Act 2000 (Financial Promotion) Order 2005
Panoro	Panoro Energy ASA
Payment Date	13 September 2021
PDPR	Petroleum (Drilling & Production) Regulations of Nigeria
PEP	Politically exposed person
Petroguin	Empresa Nacional de Pesquisa e Exploração Petroliferas E.C.P.
Petroleum Ministry	Ministry of Petroleum Resources of Nigeria
Petromal or Petromal LLC	Petromal Sole Proprietorship LLC
PetroNor Australia	PetroNor E&P Ltd.
PetroNor Norway Financial Statements	The Company's audited interim financial statements for the 1 month period ending on 31 October 2021
Petrosen	Senegal Petroleum Company
PIB	Nigerian Petroleum Industry Bill
PPNH	Pan-Petroleum Nigeria Holdings BV
PPSH	Pan-Petroleum Services Holdings BV
Prospectus	This Prospectus dated 25 February 2022
PSC	Production sharing contract
Redomicile	The Group's redomicile from Australia to Norway
Relevant Persons	All such persons together (i) who are outside the United Kingdom or (ii) investment professionals falling within Article 19(5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005 or (iii) high net worth companies, and other persons to whom the Prospectus may lawfully be communicated, falling within Article 49(2)(a) to (d) of the Order.

ROP	The Rufisque Offshore Profond block
Senegal licenses	The exploration blocks ROP and SOSP
Senegalese PSCs	Individual production sharing contracts governing the Senegal Licences
Shares	The 1,326,991,006 outstanding shares issued by the Company
Share Swap	The swap of Australian Shares for Shares in the Company, in the ratio 1:1
SNPC	Congolese National Oil Company
SOSP	The Senegal Offshore Sud Profond block
SPV or Aje Production	The new holding company Aje Production AS as part of the Aje Transaction
Symero	Symero Ltd.
Symero Transaction	The Company's acquisition of shares in HAH from Symero Ltd.
TFN	Tax file number for Australian resident shareholders
UEMOA	The West African Economic Monetary Union
USD	United States Dollar
U.S. Exchange Act	The U.S. Securities and Exchange Act of 1934
VPS	The Norwegian Central Securities Depository
VPS Registrar	DNB Bank ASA
WHO	The World Health Organization
YFP	Yinka Folawiyo Petroleum
YFP Agreement	Separate investment and shareholders' agreement with the OML-113 operator Yinka Folawiyo Petroleum
YFP-DW	YFP Deep Water Company Limited, being a Nigerian registered private company

APPENDIX A:

ARTICLES OF ASSOCIATION OF PETRONOR E&P ASA

UNOFFICIAL OFFICE TRANSLATION – IN CASE OF DISCREPANCY THE NORWEGIAN VERSION SHALL PREVAIL:

VEDTEKTER

FOR

PETRONOR E&P ASA

(org.nr. 927 866 951)

(sist endret 23. februar 2022)

§ 1 – Navn

Selskapets foretaksnavn er PetroNor E&P ASA.

§ 2 – Forretningskontor

Selskapets forretningskontor er i Oslo kommune.

§ 3 – Formål

Selskapets virksomhet er å investere i selskaper og enheter som er involvert i energibransjen og olje og gassindustrien over hele verden, samt investeringsaktiviteter og andre relaterte aktiviteter.

§ 4 – Aksjekapital

Aksjekapitalen er NOK 1 326 991,006 fordelt på 1 326 991 006 aksjer, hver pålydende NOK 0,001.

Selskapets aksjer skal være registrert i Verdipapirsentralen (VPS).

§ 5 – Styret

Selskapets styre kan ha inntil 7 medlemmer valgt av generalforsamlingen. Styret velges for normalt for inntil 2 år av gangen. Styrets leder velges av generalforsamlingen.

§ 6 – Signatur

Selskapet tegnes av to 2 styremedlem i fellesskap eller daglig leder alene. Styret kan meddele prokura.

§ 7 – Generalforsamlingen

På den ordinære generalforsamling skal følgende saker behandles og avgjøres:

ARTICLES OF ASSOCIATION

FOR

PETRONOR E&P ASA

(reg. no. 927 866 951)

(last amended on 23 February 2022)

Article 1 – Name

The company's business name is PetroNor E&P ASA.

Article 2 – Office

The company's registered office is in the municipality of Oslo.

Article 3 – Objectives

The company's business is to invest in companies and entities that are involved in the energy industry and the oil and gas industry worldwide, as well as investment activities and other related activities.

Article 4 – Share capital

The company's share capital is NOK 1,326,991.006 divided into 1,326,991,006 shares of NOK 0.001 each.

The company's shares shall be registered with Verdipapirsentralen (VPS).

Article 5 – The board of directors

The Board of Directors may have up to 7 members elected by the General Meeting. The Board is normally elected for 2 years. The Chairman of the Board is elected by the General Meeting.

Article 6 – Signature

Any two 2 Directors jointly or the CEO alone may sign for the Company. The Board may grant power of attorney.

Article 7 – The general meeting

The annual general meeting shall consider and decide the following matters:

1. Godkjennelse av årsregnskap og årsberetning.

2. Anvendelse av overskuddet eller dekning av underskudd i henhold til den fastsatte balanse, samt utdeling av utbytte.

3. Valg av styre.

4. Godkjennelse av styrets erklæring om lønn og annen godtgjørelse til ledende ansatte.

5. Andre saker som etter loven eller vedtektene hører under generalforsamlingen.

Retten til å delta og stemme på generalforsamlinger i selskapet kan bare utøves for aksjer som er ervervet og innført i aksjeeierregisteret den femte virkedagen før generalforsamlingen.

Aksjeeiere som vil delta i en generalforsamling i selskapet, skal melde dette til selskapet innen en frist som angis i innkallingen til generalforsamling, og som ikke kan utløpe tidligere enn fem dager før generalforsamlingen. Aksjeeiere som ikke har meldt fra innen fristens utløp, kan nektes adgang.

Når dokumenter som gjelder saker som skal behandles på generalforsamlingen, er gjort tilgjengelige for aksjeeierne på selskapets internettsider, gjelder ikke lovens krav om at dokumentene skal sendes til aksjeeierne. Dette gjelder også dokumenter som etter lov skal inntas i eller vedlegges innkallingen til generalforsamlingen. En aksjeeier kan likevel kreve å få tilsendt slike dokumenter.

Styret kan i forbindelse med innkalling til generalforsamlinger bestemme at aksjeeierne skal kunne avgi sin stemme skriftlig, herunder ved bruk av elektronisk kommunikasjon, i en periode før generalforsamlingen.

§ 8 – Nominasjonskomité

Selskapet skal ha en nominasjonskomité, som velges av generalforsamlingen.

1. Approval of the annual accounts and report.

2. Use of profits or coverage of losses in accordance with the approved balance sheet, as well as distribution of dividends.

3. Election of board of directors.

4. Approval of the statement from the board of directors regarding salary and other remuneration to the executive management.

5. Any other matters which pursuant to law or the Articles of Association pertain to the general meeting.

The right to participate and vote at general meetings of the company can only be exercised for shares which have been acquired and registered in the shareholders register in the shareholders on the fifth business day prior to the general meeting.

Shareholders who intend to attend a general meeting of the company shall give the company written notice of their intention within a time limit given in the notice of the general meeting, which cannot expire earlier than five days before the general meeting. Shareholders, who have failed to give such notice within the time limit, can be denied admission.

When documents pertaining to matters which shall be handled at a general meeting have been made available for the shareholders on the company's website, the statutory requirement that the documents shall be distributed to the shareholders, does not apply. This is also applicable to documents which according to statutory law shall be included in or attached to the notice of the general meeting. A shareholder may nonetheless demand to be sent such documents.

The Board of Directors may in connection with notices of general meetings determine that shareholders shall be able to cast their votes in writing, including through use of electronic communication, in a period prior to the general meeting.

Article 8 – Nomination Committee

The company shall have a nomination committee, elected by the general meeting.

Nominasjonskomitéen fremmer forslag til generalforsamlingen om (i) valg av styrets leder, styremedlemmer og eventuelle varamedlemmer, og (ii) valg av medlemmer til nominasjonskomitéen. Nominasjonskomitéen fremmer videre forslag til generalforsamlingen om honorar til styret og nominasjonskomitéen, som fastsettes av generalforsamlingen. Generalforsamlingen skal fastsette instruks for nominasjonskomiteen.

The nomination committee shall present proposals to the general meeting regarding (i) election of the chair of the Board, board members and any deputy members, and (ii) election of members of the nomination committee. The nomination committee shall also present proposals to the general meeting for remuneration of the Board and the nomination committee, which is to be determined by the general meeting. The general meeting shall adopt instructions for the nomination committee.

Nominasjonskomitéen skal bestå av inntil tre medlemmer.

The nomination committee shall consist of up to three members.

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APPENDIX B:

UNAUDITED INTERIM FINANCIAL STATEMENTS FOR THE PERIOD ENDED 30 JUNE 2021

PETRONOR E&P

Interim Financial Report

For the half year and quarter ended

30 June 2021

HIGHLIGHTS

Q2 2021 and subsequent events

Following the Private Placement of NOK 340 million in March 2021, Tranche 2a and 2b Offer shares were issued post period end in July, adding USD 11 million to the Group cash and increasing the indirect ownership in PNGF Sud up to 16.83%.

Subsequent Offering commenced 24 August 2021, targeting shareholders that were unable to take part in the Private Placement.

Purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB completed in early May.

Arbitration proceedings for Senegalese licences resumed.

Assets

Republic of Congo (Brazzaville)

On 12 March 2021, PetroNor announced a transaction to increase the indirect participation interest to 16.83% by acquisition of the non-controlling interest shares in Hemla Africa Holding AS, transaction which received shareholder approval at the EGM held on 4 May 2021 and subsequently completed on 9 July 2021.

The Group holds a right to negotiate, in good faith, along with the contractor group of PNGF Sud, the terms of the adjacent license of PNGF Bis.

Nigeria

In 2019, the Company acquired a 13.1% economic interest in the Aje Field through two transactions with Panoro and YFP. PetroNor started engaging with partners to streamline operations and initiated the DPR approval process for both transactions.

Engaged with several financial & industrial partners with a target to mature the project towards an FID.

Guinea-Bissau

78.57% interest of the Sinapa and Esperança licences are held by the Group through the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB on 4 May 2021. The licences are operated by PetroNor, and the remaining equity is held by FAR Ltd.

The Gambia

In September 2020, under the terms of the settlement agreement, a new A4 licence was awarded providing a 90% interest and operatorship of the A4 licence to the Group. The remaining 10% interest of the new licence is held by the Government of The Gambia.

Senegal

The Rufisque Offshore Profond and Senegal Offshore Sud Profond license areas held by the Group are subject to arbitration with the Government of Senegal.

EBITDA H1 (USD)
27.5 m
(H1 2020: 13.6m)

EBITDA Q2 (USD)
13.9 m
(Q2 2020 4.2m)

Consolidated net profit/loss H1 (USD)
8.9m
(2020: 2.9m)

PNGF Sud[1] & Bis[2]
19.6 MMbbl
2P Reserves

14.1 MMbbl
2C Contingent Resources

1 Assuming increase in ownership to 16.83%
2 Assuming increase in ownership to 23.56%

CEO'S STATEMENT

Dear Shareholders

During the second quarter PetroNor continued to progress a number of strategic initiatives that built on the strong platform created by the recent transformative acquisitions in Congo. The Group has delivered material growth in the two years since it merged with African Petroleum, almost doubling production and diversifying the portfolio, all against the strong headwinds of the pandemic and the associated demand crunch.

The strengthening of the oil price through the year has enhanced the already robust economics of the Group's working interest production from its cornerstone asset PNGF Sud, resulting in strong free cash flow and a strengthening of our balance sheet. Production from the asset during the period was below expectation as a result of required field maintenance to failing pump equipment. After a short delay getting the new equipment to site caused by the ongoing pandemic, the remedial work was successfully executed post period and pleasingly the production is now back around 21,000 bopd.

As mentioned, the economics from this quality asset are compelling in the current commodity price environment and will be enhanced further as a result of the impending drilling activity which is due to commence in Q3. The low operating cost at the asset was proved by the 2020 results of PetroNor and the additional production expected from the ongoing well campaign will result in significant cash-flow in the coming years. Furthermore, the JV has been through an investment cycle at the asset designed to optimise and extend production from existing wells, and the Group will therefore continue to benefit from that investment going forward.

The four well infill drilling programme at Litanzi, consisting of two producers and two injectors, is now assumed to commence in December. The new infill wells will be completed and brought on stream consecutively from January 2022. The programme will target proven undeveloped reserves in un-swept fault segments and is expected to increase the field recovery factor from 13% to 27%.

Elsewhere throughout the portfolio the management has been active in its attempts to realise value for its shareholders. The newest addition to the portfolio, in Guinea-Bissau, has been the focus of a lot of technical work, as we seek to progress this exciting opportunity. We have received early expressions of interest from leading industry players to partner with us on these blocks, reinforcing our confidence in the quality of these assets and the value proposition that they represent to our Group. We will seek to progress these discussions through the second half of the year and will update the market when we have something more concrete to announce.

During the period, the Company announced that after a period of suspension to Arbitration with Senegal, the parties had been unable to reach a satisfactory agreement and have therefore returned to Arbitration proceedings. The Group remains confident in its legal position and will leave the door open for further constructive engagement with Senegal ahead of this process nearing the formal Hearing in March next year.

Further to our settlement with The Gambia last year, which saw PetroNor regain its interest in the A4 Block under new terms, we continue to assess our options with regards to proceeding with the lease agreement ahead of the current deadline.

The Group continues to await approval from the Nigerian authorities to ratify our entry into Aje. This has been a prolonged process caused by a combination of factors mostly related to the pandemic as well as the complexity of the proposed redevelopment concept. The delay to completion has not been time lost though as we have made significant progress on enhancing the development concept for the asset and will be ready to go on this once approved. Aje remains a key part of our strategy in terms of the commercial impact we see on our business, but also the environmental and socioeconomic impact to Nigeria and its people.

PetroNor sees gas as a critical element to its ESG agenda as it seeks to eliminate gas flaring and use the gas, which is the cleanest of all hydrocarbons when burned, to replace the burning of coal and heavy diesel fuel within the domestic market and across Africa as a whole. By supplying LPG from the Aje field to the Nigerian domestic market, we can support the government with its environmental efforts and help meet growing demand in country. PetroNor's team has vast experience in LPG across the continent and is actively screening numerous opportunities that have a similar mix of liquids and gas as we have in the Aje field.

Progressing our ESG agenda remains a core priority for PetroNor. We fully recognise the importance of our accountability as an oil and gas company in the critical focus of climate change. The recent IPCC report from UN highlights the existential risk that our planet faces as a result of extractive industries. For Africa as a continent, UN had defined gas as a key transition fuel to balance the growing demand across the continent for energy, and the

CEO'S STATEMENT

socioeconomic impact of access to affordable energy play in terms fighting poverty and deforestation.

The energy transition is accelerating across Africa as IOCs continue to refocus their strategies away from oil projects and more towards renewable projects. PetroNor has a role to play in supporting this transition by positioning itself as a credible and responsible counterparty for the vendors and host governments. We believe that our proven operator status, strong industry network, and long-standing experience of doing business across the continent gives PetroNor a competitive edge that will support our inorganic growth ambitions.

In that regard, we remain focused on achieving scale and reaching our stated production target of 30,000 boepd. We are actively screening a multitude of opportunities that meet with our criteria in terms of existing production or unrealised value from proven resources that can be unlocked through a technical approach. We hope to progress some of these discussions into firm deals in the second half of this year and beyond.

In conclusion, we are pleased with the progress we are making in both our organic and inorganic strategies and enter the second half of the year with strong confidence that the Company will reap the benefits of its recently executed corporate activity. We are particularly excited about the upcoming drilling activity at PNGF Sud given the potential impact it will have on our production and cash flow now that we benefit from a larger working interest in that project. We look forward to providing regular updates to the market as we achieve key milestones throughout what will be an active and hopefully value enhancing period for the Company and its shareholders.

Yours sincerely

Knut Søvold
CEO

OPERATIONAL UPDATE

CORPORATE

General Meetings

4 May 2021

The Symero Transaction was approved by ordinary resolution which was necessary due to the related party nature of the transaction. An independent expert report was provided in advance of the General Meeting as required pursuant the Australian Corporations Act.

Ms Gro Kielland was elected as a director, after being appointed casually in February 2021 to fill a vacancy.

29 May 2021

Mr Eyas Alhomouz, Mr Roger Steinepreis and Mr Alex Neuling were all re-elected after retiring by rotation.

Capital raise and Subsequent Offering

In March 2021, the Company raised NOK 340 million of new equity through a Private Placement of 309,090,909 new shares in the Company. The Private Placement received strong interest from new investors, including institutional investors and private family offices in Norway and internationally. Petromal Sole Proprietorship LLC and related group companies ("Petromal"), the Company's main shareholder owning 38.28% of all issued and outstanding shares in the Company, subscribed for Offer Shares at the Offer Price for an amount of NOK 130.2 million, which corresponding to their 38.28% pro-rata share of the Private Placement.

The Private Placement generated NOK 187.4 million (USD 22.1 million) in cash and NOK 152.6 million (USD 18.0 million) as in-kind consideration for contingent acquisition of all Symero Limited's ("Symero") shares in Hemla Africa Holding AS ("HAH") (the "Symero Transaction"). Symero is owned by NOR Energy AS, a company owned by Knut Søvold, CEO of the Company, and Gerhard Ludvigsen.

The net cash proceeds from the Private Placement will be used to finance drilling of infill wells and other increased oil recovery initiatives on PNGF Sud and general corporate purposes. The Private Placement was divided into two tranches:

- Tranche 1 ("Tranche 1") consisting of Offer Shares for NOK 92.8 million have been allocated to existing and new investors. Tranche 1 shares were issued in March 2021 with net cash of USD 10.5 million injected into the Company after deduction of manager's fees.
- The remaining Offer Shares were issued in July 2021 to Symero (for an amount equal to NOK 152.6 million (USD 18 million) ("Tranche 2a") and Petromal (for an amount equal to NOK 94.6 million) to retain its ~38.28% ownership ("Tranche 2b").

In August 2021, the Company announced a subsequent offering of new shares without tradable subscription rights of up to 60,000,000 new shares in the Company at a subscription price of NOK 1.10 (equivalent to Private Placement price) towards existing shareholders of the Company as of close of trading on Oslo Euronext Expand on 11 March 2021, shareholders of record on 15 March 2021. A combined prospectus for listing of the Offer Shares in Tranche 2a and Tranche 2b and for the offering of shares in the contemplated Subsequent Offering was published on 23 August 2021 after approval by the Norwegian FSA.

OPERATIONS

PRODUCTION

Republic of Congo – PNGF SUD

PNGF Sud fields are located approximately 25 km off the coast of Pointe-Noire in water depths of 80-100 metres. PNGF Sud comprises 3 operating licenses, Tchibouela II, Tchendo II and Tcibeli-Litanzi II, covering five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi.

Following the entry of the new license group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bopd in January 2017 to an average production in 2020 of 22,713 bopd. Through further workovers, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

After PNGF Sud commenced production in 1987, the fields are developed with seven wellhead platforms and currently produce from 61 active production wells, with oil exported via the onshore Djeno terminal. With its long production history, substantial well count and extensive infrastructure, PNGF Sud offers well diversified and low risk production and reserves with low break-even cost.

In March 2021, AGR Petroleum prepared a Competent Person's Report ("CPR") whereby the reserves were calculated as at 31 December 2020.

Using the CPR and adjusting for H1 2021 production, as at 30 June 2021:

Participation Interest	*11.9%*	*16.83% Post Transaction*
1P reserves	9.82 MMbbls	13.9 MMbbls
2P reserves	13.87 MMbbls	19.6 MMbbls

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By end of Q2 2021, PNGF Sud contains a total 2C volume of approximately 7.30 MMbbls assuming a 16.83% participation interest.

In Q2, production has been below expectation primarily for two reasons; 1) COVID has delayed the start of infill drilling start on Litanzi from Q2 to Q4 and 2) delays in materials procurement for all operators in the country. The latter situation has been resolved and the Operator is pursuing the maintenance lag. Thus, following a reduced production in Q2, production is now back around 21,000 bopd and increasing ahead of the start of infill drilling. During H1/Q2 2021, gross production was 20,289/19,061 bopd, resulting in a net to PetroNor production of 3,372/3,208 bopd.

The current indirect participation interest is 16.83% following transactions during 2021

OPERATIONAL UPDATE

Republic of Congo – PNGF BIS

PNGF Bis is located next to PNGF Sud and contains two discoveries from 1985-1991 (Loussima SW and Loussima). The Company and its PNGF Sud partners have a right to negotiate the licence agreement.

The three discovery wells tested from 1,150 to 4,700 bopd of light, good quality oil. Perenco has made a detailed reinterpretation, 3D modelling and facilities study for the Loussima SW discovery, yielding >100 MMbbl of in-place resources and a possible tie-back to Tchibouela.

AGR Petroleum Services warrants 2C resources of 28.9 MMbbl including verification of the tieback scenario given above.

DEVELOPMENT

Nigeria – OML-113 / The AJE field

On 30 June 2021, PetroNor and Panoro Energy ASA ("Panoro") agreed to extend the completion long stop date for the previously announced purchase of Panoro's fully owned subsidiaries that hold 100% of the shares in Pan Petroleum Aje Limited ("Pan Aje") ("the Transaction"). The original long stop date was 31 December 2020, being the date by which authorisation of the Nigerian Department of Petroleum Resources and the consent of the Nigerian Minister of Petroleum Resources were required to have been received. The amended long stop date to complete the Transaction is now 30 September 2021.

The regulatory approval process in Nigeria is underway at an advanced stage but has been delayed by the pandemic and the changes in the Department of Petroleum Resources (DPR).

As previously announced, following completion of the Transaction, Panoro's intention is to declare a special dividend and distribute to its shareholders USD 10 million equivalent in PetroNor shares in order for Panoro shareholders to retain a direct listed exposure to Aje/OML-113.

Also in 2019, PetroNor entered into separate agreements with the OML-113 operator Yinka Folawiyo Petroleum ("YFP") to create a holding company to exploit the substantial gas and liquids reserves at Aje. The regulatory process for this agreement is aligned with the Transaction and is expected to be approved concurrently.

PetroNor and Panoro have also taken the opportunity to review the deferred contingent element of the Transaction, reflecting the changed macro-economic background since the original announcement in 2019. Under the original agreement, once PetroNor had recovered all its costs related to their future investments to bring Aje gas into production, the Company was to pay to Panoro additional consideration of USD 0.15 per 1,000 cubic feet of the natural gas sales, such additional consideration being capped at USD 25 million. The amended terms are for the consideration to be USD 0.10 per 1,000 cubic feet with the additional consideration being capped at USD 16.67 million.

PetroNor continues work to update the field development plan ("FDP") to expedite gas development and engaged with potential offtakers and partners. PetroNor will engage the JV partners following the DPR approval.

EXPLORATION

Guinea-Bissau – 2 and 4A & 5A

In early May 2021, the Company completed the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB, and PetroNor E&P AB has assumed the operatorship of the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau. The current phase on both licences has recently been extended for 3 years and are valid until 2 October 2023.

The licences contain two Cretaceous aged shelf edge prospects, Atum and Anchova, which are directly analogous to the on-trend Woodside operated Sangomar field development in Senegal. The prospects were mapped on 3D seismic acquired by Polarcus in 2016.

Svenska Petroleum Exploration AB was in the advanced stages of planning for the drilling of the Atum-1X well to test the Atum prospect prior to delays in gaining partner approvals due to the disputed presidential elections in late 2019 early 2020. Long lead items required for drilling operations have been secured and a number of pre-drill studies completed. Well planning can be recommenced at short notice.

The Atum-1x well will test a highly attractive and material prospect on the Sinapa licence. Recently reprocessed seismic data will be interpreted as part of the ongoing evaluation of both licences and as preparation to drilling.

The Gambia – A4

In September 2020, PetroNor E&P Gambia Ltd was awarded a new 30-year lease for the A4 licence. The award was part of a settlement agreement with the Government of The Gambia connected to the arbitration of the A1 and A4 licences previously issued in 2006.

The terms of the new license are based on the newly developed Petroleum, Exploration and Production Licence Agreement (PEPLA). PetroNor E&P Gambia Ltd will be able to carry approved prior sunk costs associated with A4 into the new agreement.

The PEPLA is a royalty plus tax system valid for 30 years with an option of a 10-year extension. The initial six years exploration period is divided into three periods of two years during which exploration activities are to be completed.

The A4 licence is located offshore within the Mauritania-Senegal-Gambia-Bissau-Conakry Basin. Hydrocarbons are proven throughout the basin, including current producing fields in Mauritania, major accumulations at Dome Flore ("AGC") and most notably the Sangomar field, 30 km to the North in Senegal. First oil is expected at Sangomar in 2023 with a plateau production rate of 100,000 bopd forecasted by the operator, Woodside. Further exploration is anticipated by FAR and Petronas in Block A2 in late 2021.

PetroNor continues to seek partners to drill one exploration well in this highly attractive acreage and aims to participate in any future well at an equity level of 30-50%.

OPERATIONAL UPDATE

Senegal – ROP & SOSP

In July 2018, the Company's subsidiary African Petroleum Senegal Limited registered arbitration proceedings with the International Centre for Settlement of Investment Disputes (ICSID) (case ARB/18/24) to protect its interests in the Senegal Offshore Sud Profond and Rufisque Offshore Profond blocks.

On 5 April 2021, the Company announced that the arbitration proceedings for the Group's interests in Senegal were to resume despite numerous progressive meetings with the relevant authorities to reach a mutually beneficial solution during the halt in proceedings during 2020 and Q1 2021.

FINANCIAL PERFORMANCE AND ACTIVITIES

The Group reported an EBITDA of USD 27.5 million for the half year ended 30 June 2021, compared to USD 13.6 million in the same period in 2020. Net profit attributable to the equity holders of the parent was USD 3.0 million for the half year ended 30 June 2021, compared to a loss of USD (0.4) million in the same period in 2020.

During the second quarter, there were two liftings that meant oil & gas revenue was (net of royalties & taxes) USD 13.6 million arising from sale of 0.20 million barrels of crude oil at an average price of USD 67.61 per barrel. In the prior year, 0.20 million barrels of crude oil was sold during the same period at an average price of USD 32.82, resulting in a revenue of USD 6.5 million.

EBITDA margin of 55% is significantly higher when compared to the Q2 2020 margin of 40%. Mostly due to improving market conditions and continued focus on cost management.

The balance of cash advanced to the Operator in Congo for decommissioning costs at 30 June 2021 was USD 23.6 million (31 December 2020: 21.3 million), this represents almost 80% of the provision required to be made under the licence arrangements. Obligations under this arrangement will be met well in advance of partnership requirements.

On 25 January 2021, a further 9,900 shares in subsidiary Hemla E&P Congo S.A. were registered for the benefit of the Group after an award by the Court in Congo. This acquisition has been considered a material non-cash transactions as it was offset with the settlement of an outstanding receivable.

With the acquisition of the Guinea-Bissau exploration operations, the Group increased its inventories with USD 1.74 million of drilling long lead items purchased originally by Svenska Petroleum for the planned Atum 1-X well. Plus, a further USD 1.26 million was incurred for the transfer fees for the existing seismic data leased by the partnership.

During the quarter no dividend was paid or recommended.

The Board of Directors (the "Board") confirms that the interim financial statements have been prepared pursuant to the going concern assumption, and that this assumption was realistic at the balance sheet date. The going concern assumption is based upon the financial position of the Group and the development plans currently in place. In the Board's view, the interim financial statements give a true and fair view of the Group's assets and liabilities, financial position, and results. PetroNor E&P Ltd is the parent company of the PetroNor Group (the "Group"). Its interim financial statements have been prepared on the assumption that the Group will continue as a going concern and the realisation of assets and settlement of debt in normal operations.

As USD 10.5 million in cash was received in the first quarter for Tranche 1 shares for the Private Placement, the Group had USD 20.4 million in cash and bank balances as of 30 June 2021 (31 December 2020: USD 14.1 million)., and the Tranche 2b shares for the Private Placement from March will raise a further USD 11.3 million in cash. A listing prospectus for the Tranche 2a and 2b shares was approved by the Norwegian FSA on 23 August 2021, together with a subsequent offering of 60,000,000 shares. If the Repair Offer is to be fully subscribed, this may raise up to a further USD 7.4 million in cash.

TOP 20 SHAREHOLDERS

As of 20 August 2021:

#	SHAREHOLDER	NUMBER OF SHARES	PER CENT
1	Petromal L.L.C [1]	481,481,666	37.42%
2	NOR Energy AS [2]	143,555,857	11.21%
3	Symero Limited[3]	138,763,636	10.83
4	Ambolt Invest AS	86,849,618	6.78
5	Gulshagen III AS [4]	45,000,000	3.51%
6	Gulshagen IV AS [4]	45,000,000	3.51%
7	ENG Group Soparfi S.A.	36,281,428	2.83%
8	Energie AS	24,983,248	1.95%
9	Nordnet Livsforsikring AS	22,604,474	1.76%
10	Enga Invest AS	14,892,746	1.16%
11	Nordnet Bank AB	12,152,621	0.95%
12	Pust For Livet AS	9,560,582	0.75%
13	Omar Al-Qattan	7,645,454	0.60%
14	Leena Al-Qattan	7,645,454	0.60%
15	UBS Switzerland AG	7,239,936	0.57%
16	Sandberg JH AS	4,853,951	0.38%
17	Danske Bank A/S	4,393,812	0.34%
18	Avanza Bank AB	4,327,243	0.34%
19	Nordea Bank Abp	3,431,244	0.27%
20	Knutshaug Invest AS	3,386,161	0.26%
	Subtotal	**1,104,048,890**	**86.20%**
	Others	176,707,307	13.80%
	Total	**1,280,756,197**	**100%**

[1] Non-Executive Chairman, Mr. Alhomouz is the CEO of Petromal L.L.C., 109,520,419, of these shares are recorded in the name of nominee company Clearstream Banking S.A. on behalf of Petromal L.L.C.

[2] NOR Energy AS is a company controlled jointly by Mr. Søvold and former Director Mr. Ludvigsen through indirect beneficial interests.

[3] Symero Ltd is a 100% owned subsidiary of NOR Energy AS

[4] Gulshagen III AS and Gulshagen IV AS are companies controlled by Mr. Søvold through an indirect beneficial interest.

OPERATIONAL UPDATE

PRINCIPAL RISKS

The Group is subject to a number of risk factors inherent in the oil and gas industry which are further detailed in the annual report. These include technical risks, reserve and resource estimates, and risks of operating in a foreign country (in particularly economic, political, social and environmental risks).

The principal risks disclosed in the annual report have not materially changed, and although the Company has raised equity finance in previous years, there may be new risks in the contemplated equity financing disclosed post period end for our investors to consider.

Risks associated with the contemplated equity financing are disclosed in the corporate presentation included with details on the proposed transactions, which is available on the Company website.

HEALTH, SAFETY AND ENVIRONMENT (HSE)

The Group's objective for health, environment, safety and quality (HSEQ) is zero accidents and zero unwanted incidents in all activities. PetroNor experienced no accidents, injuries, incidents or any environmental claims during the quarter.

The Group's operations have been conducted by the operators on behalf of the licensees, at acceptable HSE standards and the Operator of PNGF Sud is reporting regularly on all key HSE indicators. No accidents that resulted in loss of human lives or serious damage to people or property have been reported during the quarter. There have been no significant known breaches of the Company's exploration license conditions or any environmental regulations to which it is subject.

COVID-19

In the respective countries of operations, the Company followed government regulations and promoted remote working to limit the contact between internal staff and risk of infection in a small workforce. The pandemic and associated social restrictions continue to impact the freedom of movement on staff, directly and indirectly impacting supply chains for the business.

SIGNIFICANT EVENTS AFTER REPORTING DATE

On 9 July 2021, the 224,727,273 ordinary shares related to Tranche 2a and 2b of the Private Placement were issued, whereof: 138,763,636 ordinary shares for Tranche 2a of the Private Placement issued in kind as consideration for the Symero transaction, and 85,963,637 ordinary shares for Tranche 2b of the Private Placement issued for cash.

on 23 August 2021, the Company published a Listing Prospectus approved by the Norwegian FSA.

On 24 August 2021, the subscription period for a Subsequent Offering commenced targeting existing shareholders that were unable to take part or not allocated shares in the Private Placement on 11 March 2021. The Subscription Price of NOK 1.10 is equivalent to the subscription price in the Private Placement. The subscription period will end on 7 September 2021. During the subscription period, the associated Listing Prospectus will be available electronically at:

www.arctic.com/secno/en/offerings
www.paretosec.com/updates/transactions
www.sb1markets.no/en/transactions
www.petronorep.com/investors/prospectus/

Except for the above, the Company has not identified any events with significant accounting impacts that have occurred between the end of the reporting period and the date of this report.

OUTLOOK

The Company is awaiting the governmental approval Aje transaction and anticipates this to complete in the next few months.

After completion of Tranche 2a and 2b of the Private Placement, PetroNor will be in a robust financial position and fully funded for all sanctioned activities with significant flexibility to adjust its capital expenditure in a low oil price environment.

Liftings

The most recent lifting was in July 2021 for 93,816 bbl. The next lifting is expected in October. As a consequence, inventory will increase as at 30 September 2021.

Infill Drilling Program

The four well infill drilling program on Litanzi consisting of two producers and two injectors, is now assumed to commence in December and the new infill wells will be completed and brought on stream consecutively from January 2022.

CONDENSED CONSOLIDATED STATEMENT OF PROFIT OR LOSS AND OTHER COMPREHENSIVE INCOME

USD' 000 *(Unaudited)*	Three months ended 30 June **2021**	Three months ended 30 June 2020	Six months ended 30 June **2021**	Six months ended 30 June 2020
Revenue	**25,235**	10,544	**48,174**	30,263
Cost of sales	**(8,726)**	(4,790)	**(16,832)**	(12,673)
Gross profit	**16,509**	5,754	**31,342**	17,590
Other operating income	**341**	5	**357**	5
Exploration expenses	**(1,259)**	-	**(1,259)**	-
Administrative expenses	**(2,920)**	(2,444)	**(5,314)**	(5,947)
Profit from operations	**12,671**	3,315	**25,126**	11,648
Finance expense	**(947)**	(580)	**(1,626)**	(1,158)
Foreign exchange gain / (loss)	**835**	465	**19**	524
Profit before tax	**12,559**	3,200	**23,519**	11,014
Tax expense	**(8,045)**	(2,354)	**(14,654)**	(8,083)
Profit for the period	**4,514**	846	**8,865**	2,931
Other Comprehensive income:				
Exchange gains / (losses) arising on translation of foreign operations	**(565)**	1,660	**(29)**	(502)
Total comprehensive income	**3,949**	2,506	**8,836**	2,429
(Loss) / Profit for the period attributable to:				
Owners of the parent	**1,398**	(590)	**3,029**	(439)
Non-controlling interest	**3,116**	1,436	**5,836**	3,370
	4,514	846	**8,865**	2,931
Total comprehensive (loss) / income attributable to:				
Owners of the parent	**1,766**	623	**3,258**	(755)
Non-controlling interest	**2,183**	1,883	**5,578**	3,184
	3,949	2,506	**8,836**	2,429
Earnings per share attributable to members:	**USD cents**	USD cents	**USD cents**	USD cents
Basic (loss) /profit per share	**0.13 Cents**	(0.06) Cents	**0.30 Cents**	(0.05) Cents
Diluted (loss) / profit per share	**0.13 Cents**	(0.06) Cents	**0.30 Cents**	(0.05) Cents

The accompanying notes form part of these financial statements

CONDENSED CONSOLIDATED STATEMENT OF FINANCIAL POSITION

USD'000	As at 30 June 2021 *(Unaudited)*	As at 31 December 2020 *(Audited)*
Assets		
Current assets		
Inventories	**5,724**	3,578
Trade and other receivables	**8,506**	9,397
Cash and cash equivalents	**20,444**	14,113
	34,674	27,088
Non-current assets		
Property, plant and equipment	**22,592**	23,483
Intangible assets	**6,890**	6,935
Right-of-use assets	**127**	212
Other receivables	**23,552**	21,260
	53,161	51,890
Total assets	**87,835**	78,978
Liabilities		
Current liabilities		
Trade and other payables	**15,553**	22,238
Lease liability	**142**	170
Loans and borrowings	**8,000**	4,000
	23,774	26,408
Non-current liabilities		
Loans and borrowings	**10,078**	14,912
Lease liability	**-**	55
Provisions	**15,805**	15,307
	25,883	30,274
Total liabilities	**49,578**	56,682
NET ASSETS	**38,257**	22,296
Issued capital and reserves attributable to owners of the parent		
Share capital	**28,138**	17,735
Foreign currency translation reserve	**(727)**	(956)
Retained earnings	**(5,824)**	(8,853)
	21,587	7,926
Non-controlling interests	**16,670**	14,370
TOTAL EQUITY	**38,257**	22,296

The accompanying notes form part of these financial statements

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

USD' 000 *(Unaudited)*	**Issued capital**	**Retained earnings**	**Foreign currency translation reserve**	**Non-controlling interest**	**Total**
BALANCE AT 1 JANUARY 2021	**17,735**	**(8,853)**	**(956)**	**14,370**	**22,296**
Profit for the period	-	3,029	-	5,836	8,865
Other comprehensive loss	-	-	229	(258)	(29)
Total comprehensive income / (loss) for the period	-	**3,029**	**229**	**5,578**	**8,836**
Issue of capital	10,945	-	-	-	10,945
Share Issue Costs	(542)				(542)
Acquisition of equity interest from NCI	-	-	-	(3,278)	(3,278)
BALANCE AT 30 JUNE 2021	**28,138**	**(5,824)**	**(727)**	**16,670**	**38,257**
For the period ended 30 June 2020					
BALANCE AT 1 JANUARY 2020	17,735	(11,226)	-	14,749	21,258
Profit for the period	-	(439)	-	3,370	2,931
Other comprehensive income	-	-	(316)	(186)	(502)
Total comprehensive loss for the period	-	(439)	(316)	3,184	2,429
Dividend paid	-	-	-	(5,150)	(5,150)
BALANCE AT 30 JUNE 2020	17,735	(11,665)	(316)	12,783	18,537

The accompanying notes form part of these financial statements

CONDENSED CONSOLIDATED STATEMENT OF CASH FLOWS

USD' 000 *(Unaudited)*	For the period ended 30 June 2021	For the period ended 30 June 2020
Cash flows from operating activities		
Total comprehensive (loss) / income for the period	**8,836**	2,429
Adjustments for:		
Income tax expense	**14,654**	8,083
Depreciation and amortisation	**2,333**	1,946
Amortization of right-of-use asset	**85**	-
Unwinding of discount on decommissioning liability	**497**	467
	26,405	12,925
Increase in trade and other receivables	**(2,387)**	(2,547)
Increase in advance against decommissioning cost	-	(3,039)
Increase in inventories	**(2,146)**	(619)
Decrease in trade and other payables	**(6,685)**	(10,246)
Cash generated from operations	**(11,218)**	(3,526)
Income taxes paid	**(14,654)**	(8,083)
Net cash flows from operating activities	**533**	(11,609)
Investing activities		
Purchases of property, plant and equipment	**(1,385)**	(2,079)
Advance against decommissioning cost	**(2,292)**	-
Net cash flows from investing activities	**(3,677)**	(2,079)
Financing activities		
Proceeds from loans and borrowings	-	15,000
Repayment of loans and borrowings	**(834)**	(12,941)
Repayment of principal portion of lease liability	**(89)**	-
Repayment of interest portion of lease liability	**(5)**	-
Issue of share capital	**10,945**	-
Share Issue Costs	**(542)**	-
Dividends paid	-	(5,150)
Net cash (used in)/ from financing activities	**9,475**	(3,091)
Net increase / (decrease) in cash and cash equivalents	**6,331**	(16,779)
Cash and cash equivalents at beginning of period	**14,113**	27,891
Cash and cash equivalents at end of period	**20,444**	11,112

The accompanying notes form part of these financial statements

NOTES TO THE INTERIM FINANCIAL REPORT

Corporate information

The condensed financial report of the Company and its subsidiaries (together the "Group") for the period ended 30 June 2021 was authorised for issue in accordance with a resolution of the directors on 31 August 2021.

PetroNor E&P Limited is a 'for profit entity' and is a company limited by shares incorporated in Australia. Its shares are publicly traded on the Oslo Euronext Expand (code: PNOR), a regulated marketplace of the Oslo Stock Exchange, Norway. The principal activities of the Group are the exploration and production of crude oil.

Basis of preparation

This general purpose condensed interim financial report for the quarter ended 30 June 2021 has been prepared in accordance with IAS 34 Interim Financial Reporting and the supplement requirements of the Norwegian Securities Trading Act (Verdipapirhandelloven).

The interim financial report does not include all notes of the type normally included within the annual financial report and therefore cannot be expected to provide as full an understanding of the financial performance, financial position and financing and investing activities of the Company as the full financial report.

It is recommended that the interim financial report be read in conjunction with the annual report for the year ended 31 December 2020 and considered together with any public announcements made by the Company during the period ended 30 June 2021 in accordance with the continuous disclosure obligations of Oslo Euronext Expand. A copy of the annual report is available on the Company's website www.petronorep.com.

The interim financial report is presented in United States Dollars being the functional currency of the Company.

Accounting policies

The accounting policies adopted are consistent with those disclosed in the annual report for the year ended 31 December 2020.

Significant accounting judgements, estimates and assumptions

The preparation of the interim financial report entails the use of judgements, estimates and assumptions that affect the application of accounting policies and the amounts recognised as assets and liabilities, income and expenses. The estimates and associated assumptions are based on historical experience and other factors that are considered to be reasonable under the circumstances. The actual results may deviate from these estimates. The material assessments underlying the application of the Company's accounting policies and the main sources of uncertainty are the same for the interim accounts as for the annual accounts for 2020.

NOTES TO THE INTERIM FINANCIAL REPORT

Revenue from contracts with customers

USD'000 *(Unaudited)*	*Three months ended 30 June*		*Six months ended 30 June*	
	2021	2020	**2021**	2020
Revenue from contracts from customers				
Revenue from sales of petroleum products	**13,581**	6,473	**26,460**	17,443
Other revenue				
Assignment of tax oil	**8,045**	2,354	**14,654**	8,083
Assignment of royalties	**3,609**	1,717	**7,061**	4,737
Total revenue	**25,235**	10,544	**48,174**	30,263
Number of liftings	**2**	1	**4**	3
Quantity of oil lifted (Barrels)	**200,884**	197,221	**420,360**	467,003
Average selling price (USD per barrel)	**67.61**	32.82	**62.95**	37.35
Quantity of net oil produced after royalty, cost oil and tax oil (Barrels)	**191,079**	284,680	**402,701**	520,611

Cost of sales

USD'000 *(Unaudited)*	*Three months ended 30 June*		*Six months ended 30 June*	
	2021	2020	**2021**	2020
Operating expenses	**3,691**	3,606	**7,342**	6,509
Royalty	**3,609**	1,717	**7,061**	4,737
Depreciation and amortisation of oil and gas properties	**1,143**	870	**2,315**	1,934
Movement in oil inventory	**283**	(1,403)	**114**	(508)
	8,726	4,790	**16,832**	12,673

Exploration expenses

USD'000 *(Unaudited)*	*Three months ended 30 June*		*Six months ended 30 June*	
	2021	2020	**2021**	2020
Seismic data acquisition	**1,259**	-	**1,259**	-
	1,259	-	**1,259**	-

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Administrative expenses

USD'000 (Unaudited)	Three months ended 30 June 2021	Three months ended 30 June 2020	Six months ended 30 June 2021	Six months ended 30 June 2020
Employee benefit expenses	**1,324**	1,278	**2,464**	2,514
Termination benefits	**-**	-	**-**	795
Travelling expenses	**42**	20	**57**	224
Legal and professional	**982**	699	**1,527**	1,566
Other expenses	**572**	447	**1,266**	848
	2,920	2,444	**5,314**	5,947

Finance cost

USD'000 (Unaudited)	Three months ended 30 June 2021	Three months ended 30 June 2020	Six months ended 30 June 2021	Six months ended 30 June 2020
Unwinding of discount on decommissioning liability	**249**	234	**497**	467
Interest accrued on right-of-use liability	**2**	-	**5**	-
Interest on loan	**696**	346	**1,124**	691
	947	580	**1,626**	1,158

Earnings per share

USD'000 (Unaudited)	Three months ended 30 June 2021	Three months ended 30 June 2020	Six months ended 30 June 2021	Six months ended 30 June 2020
Profit / (loss) from continuing operations attributable to the equity holders used in calculation	**1,398**	(590)	**3,029**	(439)
	Number of shares			
Weighted average number of shares used in the calculation of:				
Basic profit per share	**1,056,028,924**	971,665,288	1,023,204,253	971,665,288
Diluted profit per share	**1,057,418,394**	971,665,288	1,021,814,783	971,665,288

Options on issue are considered to be potential ordinary shares and have been included in the determination of diluted loss per share only to the extent to which they are dilutive. There are 1,389,470 options as at 30 June 2021 (30 June 2020: 2,279,470 options).

Post period end on 9 July 2021, the 224,727,273 ordinary shares related to Tranche 2a and 2b of the Private Placement were issued.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Inventories

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Crude oil inventory	576	689
Materials and supplies	5,148	2,889
	5,724	3,578

Crude oil inventory is valued at cost (not related to sales value) of USD 21.22 per bbl (2020: USD 15.79 per bbl).
Materials inventory of USD 1.735 million were acquired with The Sinapa and Esperança Guinea-Bissau licences.

Trade and other receivables

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Recoverability less than one year:		
Trade receivables	7,713	5,408
Due from related parties	-	3,639
Advance against decommissioning cost	-	-
Other receivables	793	350
	8,506	9,397
Recoverability more than one year:		
Advance against decommissioning cost	23,552	21,260
	23,552	21,260

Cash and bank balances

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Cash in bank	20,424	14,113
Restricted cash	20	-
	20,444	14,113

Material non-cash transaction
The acquisition of an additional 9,900 shares of subsidiary company Hemla E&P Congo S.A. was considered in settlement of the USD 3.6 million historic outstanding receivable from MGI International S.A.

Production assets and equipment

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Cost	34,568	33,445
Depreciation	(11,976)	(9,962)
Net carrying amount	22,592	23,483

Intangible assets

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Net carrying value		
Licences and approval	6,887	6,930
Software	3	5
	6,890	6,935

Trade and other payables

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Trade payables	6,427	5,226
Due to related parties	5,482	11,694
Taxes and state payables	254	348
Other payables and accrued liabilities	3,390	4,970
	15,553	22,238

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (CONTINUED)

Loans payable

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Ageing of loans payable		
Current	**8,000**	**4,000**
Non-current	**10,078**	**14,912**
	18,078	**18,912**

Decommissioning liability

In accordance with the agreements and legislation, the wellheads, production assets, pipelines and other installations may have to be dismantled and removed from oil and natural gas fields when the production ceases. The exact timing of the obligations is uncertain and depend on the rate the reserves of the field are depleted. However, based on the existing production profile of the PNGF Sud field and the size of the reserves, it is expected that expenditure on retirement is likely to be after more than ten years. The current bases for the provision are a discount rate of 6.0% and an inflation rate of 1.6%. The Group reassessed the applicable discount rate during 2020 based on the rates of Congolese Government bonds issued in the Congo during the year.

Share capital

In March 2021 the Company completed a Private Placement divided into two tranches. For Tranche 1, 84,363,636 ordinary shares were issued for no par value and a subscription price of NOK 1.10 to existing and new investors.

For Tranche 2a and 2b 224,727,273 new ordinary shares have been issued in Q3 2021.

Related party transactions

Balances due from and due to related parties disclosed in the consolidated statement of financial position:

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Loan receivable from MGI International S.A.	-	3,639
Total from related parties	-	3,639

USD'000	30 June 2021 (Unaudited)	31 December 2020 (Audited)
Other payables include:		
Nor Energy AS	**3,377**	3,378
Petromal – Sole Proprietorship LLC	**2,022**	2,030
Symero Ltd	**83**	108
MGI International S.A.	-	6,178
Total to related parties	**5,482**	11,694
Loan payable to Symero Ltd	**3,912**	3,912
Loan payable to related parties	**3,912**	3,912

Events subsequent to reporting date

On 9 July 2021, the 224,727,273 ordinary shares related to Tranche 2a and 2b of the Private Placement were issued, whereof: 138,763,636 ordinary shares for Tranche 2a of the Private Placement issued in kind as consideration for the Symero transaction, and 85,963,637 ordinary shares for Tranche 2b of the Private Placement issued for cash.

on 23 August 2021, the Company published a Listing Prospectus approved by the Norwegian FSA.

On 24 August 2021, the subscription period for a Subsequent Offering commenced targeting existing shareholders that were unable to take part or not allocated shares in the Private Placement on 11 March 2021. The Subscription Price of NOK 1.10 is equivalent to the subscription price in the Private Placement. The subscription period will end on 7 September 2021. During the subscription period, the associated Listing Prospectus will be available electronically at:

www.arctic.com/secno/en/offerings
www.paretosec.com/updates/transactions
www.sb1markets.no/en/transactions
www.petronorep.com/investors/prospectus/

Except for the above, the Company has not identified any events with significant accounting impacts that have occurred between the end of the reporting period and the date of this report.

STATEMENT OF RESPONSIBILITY

We confirm that, to the best of our knowledge, the condensed set of unaudited financial statements for the quarter ended 30 June 2020, which has been prepared in accordance with IAS34 Interim Financial Statements, provides a true and fair view of the Company's consolidated assets, liabilities, financial position and results of operations, and that the management report includes a fair review of the information required under the Norwegian Securities Trading Act section 5-6 fourth paragraph.

Approved by the Board of PetroNor E&P Limited:

Eyas Alhomouz, Chairman of the Board

Jens Pace, Director of the Board

Joseph Iskander, Director of the Board

Roger Steinepreis, Director of the Board

Gro-KIelland, Executive Director of the Board

Ingvil Smines Tybring-Gjedde, Director of the Board

Alexander Neuling, Director of the Board

CORPORATE DIRECTORY

DIRECTORS

Eyas Alhomouz Chairman
Joseph Iskander
Gro Kielland
Alexander Neuling
Jens Pace
Roger Steinepreis
Ingvil Smines Tybring-Gjedde

COMPANY SECRETARY
Angeline Hicks

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STOCK EXCHANGE LISTING
Oslo Euronext Expand
Code: PNOR

APPENDIX C:

AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED 31 DECEMBER 2020

PETRONOR E&P

Robust performance. Positioned for growth.

Annual report for the year ended
31 December 2020

Contents

About us

PetroNor E&P, listed on the Oslo Euronext Expand (PNOR), is an independent oil and gas company led by an experienced board and management team, with substantial experience in oil and gas exploration, appraisal, development and production.

Our Mission

Our mission is to generate shareholder value by leveraging the technical and commercial skillset of the Company to enhance its reserve base, production and cash flow. PetroNor E&P is committed to the highest standards of corporate governance, transparent stakeholder engagement and operational excellence.

Our Vision

Our strategic vision is to steadily build the company into a fullcycle, Africa-focused exploration and production company with an emphasis on producing and developing assets with upside potential. To reflect growth ambitions, the Board has set a target of achieving reserves of 300 MMbbl and production of 30,000 barrels of oil equivalent per day (boepd) over a three year period.

Our Work

We are an independent oil and gas exploration and production company with licences in countries in West Africa – Republic of Congo, Guinea-Bissau, Senegal, The Gambia and Nigeria. The Company has amassed a diverse and high-quality portfolio comprising economically-robust production, development upside, and high-impact exploration in the MSGBC basin.

Find out more online:
www.petronorep.com

2020 & Post period

Completed a capital raise of NOK 340 million in March 2021 to fund acquisition of additional interest in PNGF Sud and to fund share of costs for next drilling activity at the asset.

PetroNor has increased its indirect ownership in PNGF Sud up to 16.83% through increasing its shareholding in Hemla E&P Congo and Hemla Africa Holding. The latter transaction is awaiting approval by the EGM 4 May 2021.

PNGF Sud production had a 4% growth in the oil production compared to 2019 with a gross field average production of 22,713 bopd in 2020.

PetroNor has further enhanced a highly attractive exploration portfolio in the West African margin through the entry in the Esperança and Sinapa licenses in Guinea-Bissau at highly attractive terms following the acquisition of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB.

Extension of the long stop date for the Aje transaction from 31 December 2020 to 30 June 2021, allowing extra time for completion of the regulatory approval process in Nigeria which has been delayed by the COVID-19 pandemic.

EBITDA (USD)

33.97m

2019: 49.00m

EBIT (USD)

29.33m

2019: 45.77m

Net profit/(loss) (USD)

11.15m

2019: (5.76)m

2P Reserves (MMbbl)

20.23*

2019: 10.76

2C Contingent Resources (MMbbl)

14.11*

2019: 7.31

* Assuming the increase PNGF Sud in ownership had taken place as of 31 December 2020

Assets

Republic of Congo (Brazzaville)

10.5% indirect participation interest in the license group of PNGF Sud (Tchibouela II, Tchendo II and Tchibeli-Litanzi II) through Hemla E&P Congo S.A.

On 25 January 2021, the indirect participation interest increased to 11.9% after 9,900 shares in Hemla E&P Congo awarded by the court in Congo were registered for the benefit of the Company.

On 12 March 2021 a transaction to increase the indirect participation interest to 16.83% by acquisition of the non-controlling interest shares in Hemla Africa Holding AS, the transaction is subject to approval by the Extraordinary General Meeting which will be held 4 May 2021.

The Group holds a right to negotiate, in good faith, along with the contractor group of PNGF Sud, the terms of the adjacent license of PNGF Bis and a 14.7% indirect participation.

Nigeria

In 2019 acquired 13.1% economic interest in Aje Field through two transactions with Panoro Energy ASA and Yinka Folawiyo Petroleum. Started engaging with partners to streamline operations and made positive progress towards the Department of Petroleum Resources approval for both transactions. PetroNor will be the technical assistant to the Operator.

The MSGBC Basin

Further enhanced a highly attractive exploration portfolio across the MSGBC basin.

In April 2021, the approval for acquiring the 78.57% interest in the Sinapa and Esperança from Svenska Petroleum Exploration was received from the Government of Guinea-Bissau.

In September 2020, a new A4 license was awarded in The Gambia providing a 90% interest and operatorship to the Group.

In Senegal, the Rufisque Offshore Profond and Senegal Offshore Sud Profond license areas held by the Group are subject to arbitration with the Government of Senegal.

Eyas Alhomouz
Chairman

Transformational business

Last year presented numerous operational and corporate challenges as PetroNor, like all companies in the sector, was impacted by commodity price volatility and the broader issues created by the pandemic. Fortunately, the Company was able to ride out the turbulence and emerge healthy as a result of a robust cornerstone asset and a firm commitment to cost discipline.

The impact of the pandemic was severe on the oil and gas sector as demand came to a hard stop as global lockdowns came into force. Our activities were relatively unaffected as the operator did a good job of maintaining production at our asset in Congo, however the general backdrop created a lot of logistical challenges in communication and forward planning, resulting in delays to the completion of various corporate initiatives. The global rollout of vaccines has led to a good recovery in the sector and the global economic outlook, and we remain cautiously optimistic that the worst is behind us and that the Company is well placed to benefit from the macro tailwinds.

PetroNor's resilience through this turbulence reflects our diversified business model and commitment to cost control. The Company is continuously seeking to reduce its cost base and has made good headway in this regard, even prior to the pandemic. The diversification of the portfolio will continue to be a focus as we seek to achieve our stated ambition of becoming an established, full-cycle, Pan-African operator with the appropriate blend of production, development and exploration upside.

The sector turmoil in the last year, exacerbated by an accelerating Energy Transition, is creating a compelling market dynamic for PetroNor's inorganic growth

"PetroNor's resilience through this turbulence reflects our diversified business model and commitment to cost control."

strategy. The Company continues to actively screen and review opportunities consistent with our strategy, namely assets that provide immediate or near-term cash flow. We are witnessing a growing pipeline of opportunities of all sizes driven by the structural changes taking place in the industry. The industry ecosystem is changing and credible operators with a firm commitment to environmental and socioeconomic responsibilities will be required to enable the various stakeholders within the ecosystem to achieve their respective objectives. PetroNor is firmly positioned to be a partner of choice and we look forward to demonstrating these capabilities.

Our existing portfolio continues to evolve in line with our stated strategy. The pandemic has caused delays to completion of the Nigeria and Guinea-Bissau transactions however we are pleased that the Guinea-Bissau transaction received the required in-county regulatory approvals in late April 2021. The team has already put in a lot of technical work into the Aje re-development and our plans to reduce the flaring from that project will demonstrate our commitment to the reduction of the carbon footprint of our activities and overall approach to ESG. The settlement with The Gambia and reinstatement of the A4 licence vindicated our efforts to resolve that dispute and we look forward to working alongside the government in exploring that licence. We also hope to reach a solution with regards to Senegal and remain open to negotiation.

Our purpose is to ensure a positive impact with all that we do, and we are wholly focused on being a good citizen in the countries in which we work. We have active programmes in the Republic of Congo for education and continue to support the government in its fight against COVID-19. The Board seeks to continuously enhance its Governance and has made good progress in this regard with a stronger focus on Independence and Diversity in the boardroom. We will also continue to enhance our ESG agenda, recognising that this is a critical aspect of how we run our business.

The fundraise completed post-period, that enabled the transformative acquisition of an additional interest in PNGF Sud and funding for the infill drilling programme at the asset later this year, demonstrated the continued support the Company has from its shareholder base. These events will provide more scale and stability to the business, and leave us well placed to achieve our longer term growth objectives.

On behalf of the Board, I would like to thank all of our shareholders for their support and patience in these turbulent times. The Board and Management are wholly aligned with the wider shareholder base in terms of wishing to see PetroNor generate long-term sustainable value and believe that we have put in place the building blocks to enable that goal. I would also like to thank our management team for their commitment and believe that our team's experience and expertise are very much central to our investment proposition.

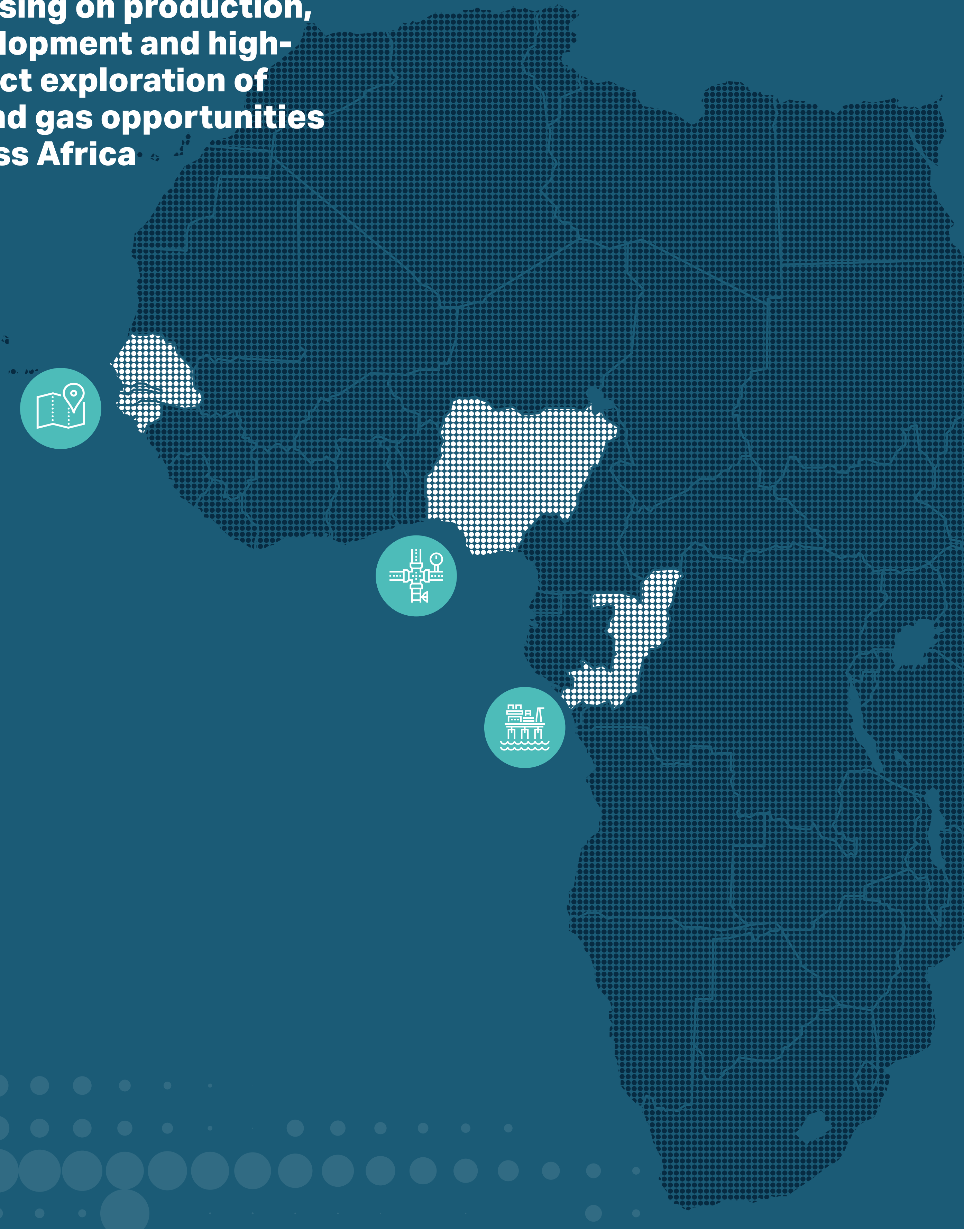
In summary, our Company has successfully navigated through the choppy waters of last year and is now well positioned to continue its growth journey with a positive wind in its sails. This year has the potential to be truly transformational for PetroNor and we look forward to communicating our progress as various operational and corporate initiatives come to fruition.

Sincerely,
Eyas Alhomouz
Chairman

"Our purpose is to ensure a positive impact with all that we do, and we are wholly focused on being a good citizen in the countries in which we work."

Our portfolio

Focusing on production, development and high-impact exploration of oil and gas opportunities across Africa



Production

Congo Brazzaville

Congo Brazzaville is a core country for PetroNor, both for production as well as for regional expansion.

Our asset, PNGF Sud is operated by Perenco – a world leading company specialised in low-cost tail production assets like PNGF Sud.

The reserves have increased year-on-year and the production has continued to grow and the operating cost has been significantly reduced, all achieved through work-over and maintenance work.

The license partnership has now embarked on a growth plan to drill more than 10 new wells with a three-year investment program of USD 250 million.

Production (net) (bopd)
3,850

2C Resources (net) (MMbbl)
8.81

2P Reserves (net) (MMbbl)
20.2

Development

Nigeria

Nigeria is a strategic target area for PetroNor due to the significant number of undeveloped assets in the country.

PetroNor has created a joint venture together with the operator YFP for the revitalisation of the Aje field.

Current oil and condensate production at the Aje field to be increased up to 8,000 bopd with the liquids only, and 20,000 boepd including the gas development.

PetroNor is seeing a significant number of opportunities for merger and acquisition (M&A) in Nigeria.

2P Economic interest
13.1%

2C Economic Interest
17.4%

2P Reserves (net) (MMbbl)
0.2

2C Resources (net) (MMboe)
18.7

Nominal interest
6.5%

Production (net) (bopd)
260

Exploration

The MSGBC Basin

PetroNor has further enhanced a highly attractive exploration portfolio across the MSGBC (Mauritania-Senegal-Guinea-Bissau-Conakry) basins.

In late 2020, PetroNor entered into the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licenses offshore Guinea Bissau through the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration.

Following completion in May 2021 PetroNor will assume Operatorship and an interest of 78.57% of the licenses. The offshore licenses, covering approximately 5,000 km², are located on a highly prospective trend in the MSGBC. The Atum and Anchova prospects are analogous to the world class Sangomar field in Senegal and are commercially attractive with net combined P50 recoverable prospective resources of 498 MMbbl (Svenska Petroleum Exploration estimate).

Net unrisked prospective resources (bbl)
4 Bn

Our portfolio

Production

Congo Brazzaville

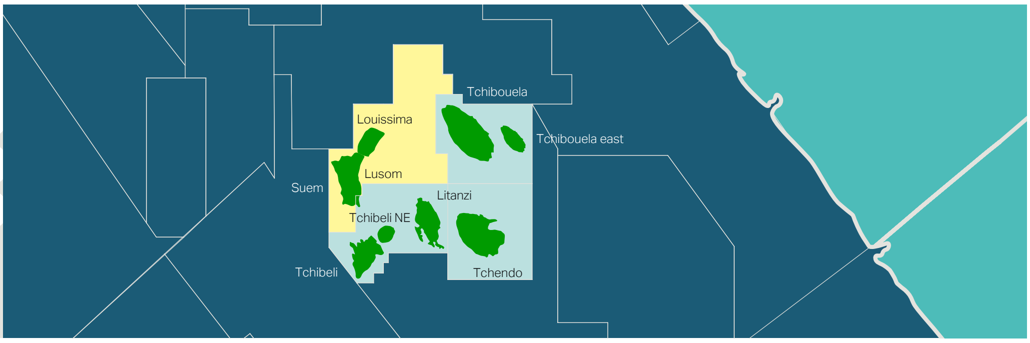
Production (net) (bopd)
3,850

2P Reserves (net) (MMbbl)
20.2

2C Resources (net) (MMbbl)
12.6

5 fields
16.83% Indirect Interest[1]

[1] The ownership in PNGF Sud is increased from 10.5 % to 16.83% during 2021 and will be completed when the EGM approved transaction is completed



The Republic of Congo (Congo-Brazzaville) is a leading producer of crude oil, representing around 90% of the exports of the country.

The majority of the production in Congo is located offshore, with approximately half in deep water.

PNGF Sud

Licence overview

In 2016 production rates were less than 15,000 bopd when Total exited and the current partnership took over the licence with Perenco as operator. Since then, low-cost brick by brick improvements via workovers and production process improvements have resulted in year by year growth in both production and reserves.

Licence activity

Low cost production – lifting cost of 10.4 USD/bbl.

Gross production of 22,700 bopd (2020 average).

Very successful well workover programme to maintain a high number of active wells and effectively drain the significant in-place oil present where the recovery factor is only 23% to date.

New high-quality 3D reservoir models now being utilized for field management and planning of infill drilling activities starting late 2021 on several structures, of which 15 wells have been sanctioned only to date.

Continous de-bottlenecking of production system with particular emphasis on total fluid management.

Gross reserves and resources

	Volume (MMbbl)
2P	120.2
2C	43.4
STOIIP	2,029
Accumulated produced 01 January 2021	459

These reserves and resources are a result of a successful workover and infill drilling planning programme in all the PNGF fields. The remaining 2P reserves have more than doubled since 1 January 2017. Taking account of the 60% increase in PetroNor equity and production in the period, the reserves have increased by a factor of 3.6.

Net interest[2]

16.83%

Producing wells

65

[2] Figures assuming EGM approved transaction has been completed

PNGF Bis

Licence overview

PNGF Bis is located next to PNGF Sud and contains two discoveries from 1985-1991 (Loussima SW and Loussima). The partnership has a right to negotiate the licence on given terms.

The three discovery wells tested from 1,150 to 4,700 bopd of light, good quality oil. Perenco has recently made a detailed reinterpretation, 3D modelling and facilities study for the Loussima SW discovery, yielding >100 MMbbl of in-place resources and a possible tie-back to Tchibouela.

AGR Petroleum Services warrants 2C resources of 29 MMbbl including verification of the tie-back scenario given above.

Net interest[2]

23.56%

Reserves growth through infill drilling 2021-23

Litanzi

Jackup acquired and modified with simple processing – oil and water to Tchendo.

Two infill producers and two infill injectors targeting upswept fault terraces.

Estimated recovery of 7.5 MMbbl.

Total estimated CAPEX of USD 105 million gross (14 USD/bbl) yielding attractive economics.

Economics attractive for reserve additions with between 8-13 USD/bbl of CAPEX.

Tchendo

Wellhead platform installed with available 14 slots for infill drilling of which seven have been sanctioned, following drilling of Litanzi in 2022.

Total cost USD 96 million including infrastructure and wells. The total cost for infrastructure and 14 wells is 9 USD/bbl.

Tchibeli

A four well infill program has been sanctioned and will follow the Tchendo drilling 2022. The total reserves is estimated to 7 MMbbl with a development CAPEX of 7.5 USD/bbl.

Tchibeli NE

A two well development programme is considered with ~12 MMbbl and development CAPEX of 7.5 USD/bbl with a 5 km tie-back to Tchibeli.

Our portfolio

Development

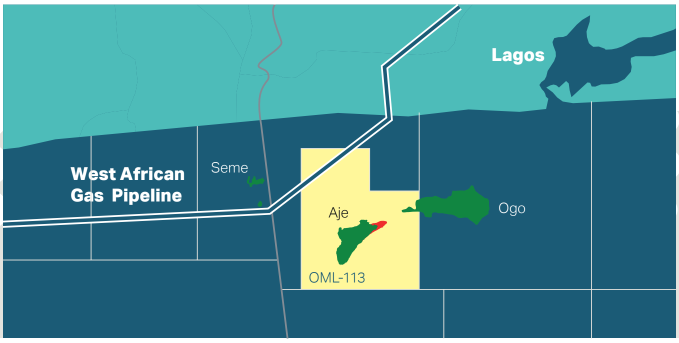
Nigeria

2C Resources (net) (MMbboe)
18.7

Production (bopd)
1,981
260 net

2P Reserves (net) (MMbbl)
0.2

Nominal interest
6.5%



Nigeria is one of the most petroleum-rich nations in the world. Nearly all of the country's primary reserves are concentrated in and around the Niger Delta. Nigeria is one of the few major oil-producing nations still capable of increasing its oil output.

OML-113 (Aje Field)

Licence overview
The Aje Field was discovered after drilling of the Aje-1 well in 1996. The OML-113 block covers 835 km² with water depths ranging from 100m to 1,500m. Five wells have been drilled; oil production is from Turonian and Cenomanian age reservoirs. PetroNor acquired the Panoro equity share in the field in 2019.

An SPV has been setup with the operator Yinka Folawiyo Petroleum whereby PetroNor have joint technical operatorship (subject to final approval by the Nigerian government). Overlying the Turonian oil rim is a significant gas-condensate discovery which has not been developed. Gas produced from the field is flared.

Forward plan
Aje development plans are being finalised, and will be presented to the joint venture partners following the Nigerian government's approval of the transactions.

The development plans will target the gas, condensate and oil in a low-risk development plan. Wet gas will be brought to shore for further processing and extraction of LPG Gas

Several scenarios are being considered and will be concluded prior to FID later in 2021. The Nigerian government encourages stop-flaring programs and the country is in dire need of electrical power.

Licence activity
Aje Field Development Plan ("FDP") is focused on producing and commercializing the gas. Condensate will be stripped from the gas produced offshore and "dry" gas will be reinjected until gas commercialization is available. The flared gas will be reinjected to stop the resource waste and allow for a gas recycling process.

Gas commercialization options include direct sales of rich gas through Gas Sales Agreements or through Swap agreement through GACN. The plan will include connecting to WAGP, which will be the main infrastructure for Gas delivery through sales or swap agreements. Further processing in a purpose- built gas plant is also considered to extract additional liquids (LPG and condensate) before the gas is sold to the local market.

The current FPSO is not suitable for the future FDP, and plans will include an FPSO suitable for FDP gas handing and processing.

2C Economic Interest
17.4%

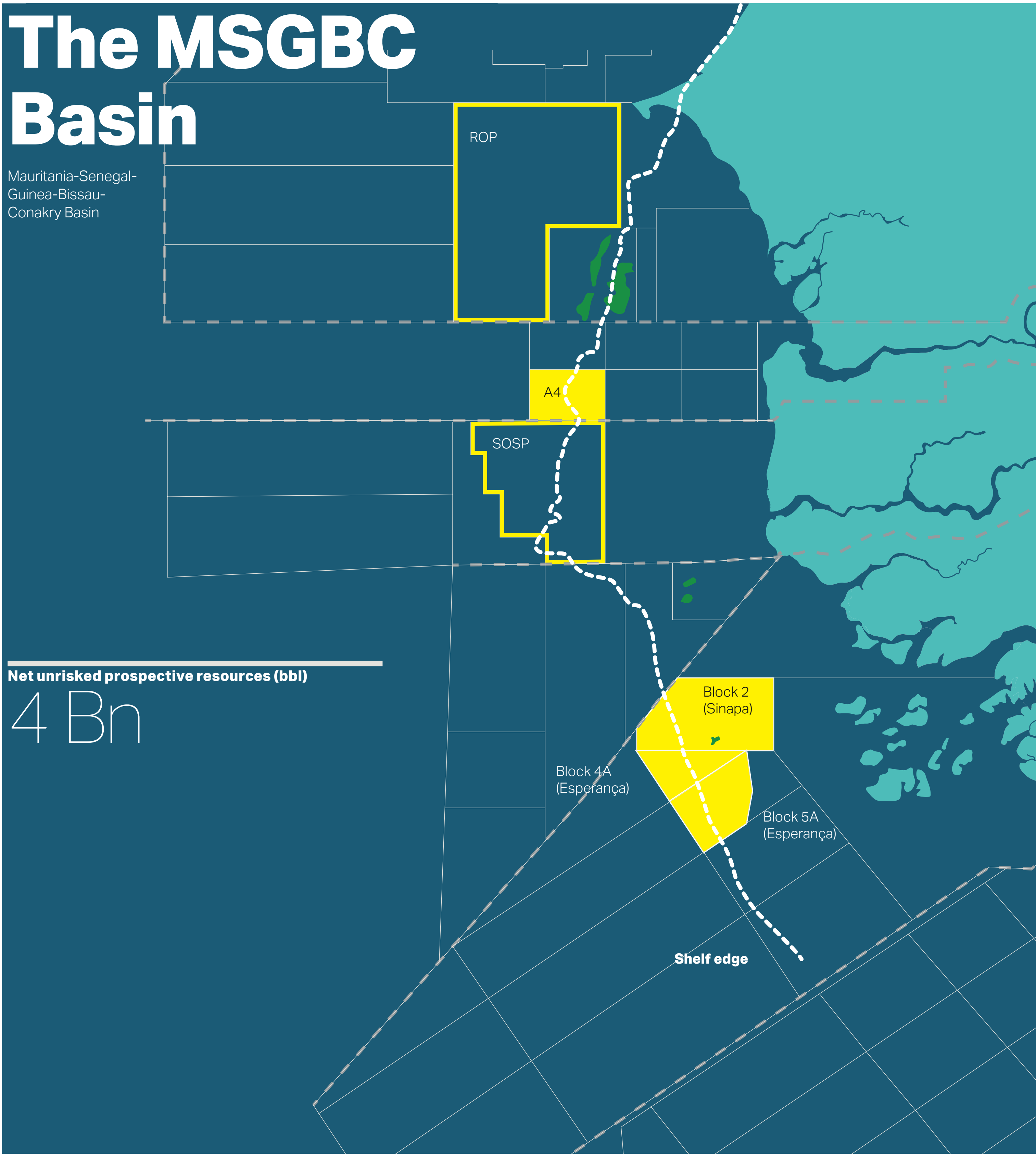
2P Economic interest
13.1%

Our portfolio

Exploration

The MSGBC Basin

Mauritania-Senegal-Guinea-Bissau-Conakry Basin



Net unrisked prospective resources (bbl)

4 Bn

Guinea-Bissau

Net working interest
78.57%

Area
4,963 km^2

Operator
PetroNor E&P AB

Net unrisked prospective resources (bbl)
>0.5 Bn

Licence overview
In October 2020, the current Exploration phases for the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau were extended for 3 years and are valid until October 2023.

The Company purchased SPE Guinea Bissau AB from Svenska Petroleum Exploration AB, and the transaction received formal in-country governmental approval in late April 2021. Subsequently, PetroNor has assumed operatorship of the licences through the renamed Svenska subsidiary acquired, PetroNor E&P AB.

During 2020, the operations on the licences were suspended due to COVID-19.

PetroNor intends to build on the work of the previous Operator, and re-initiate planning for drilling of the Atum-1X well, to test a highly attractive and material prospect on the Sinapa licence, analogous to the Sangomar field in Senegal. Recently reprocessed seismic data will be interpreted as part of the ongoing evaluation of both licences.

The Gambia

Net working interest
90%

Area
1,376 km^2

Operator
PetroNor E&P Gambia Ltd

Net unrisked prospective resources (bbl)
2.0 Bn

Licence overview
The Company was awarded a new 30-year lease for the A4 licence in September 2020. The award was part of a settlement agreement with the Government of The Gambia connected to the arbitration of the A1 and A4 licences previously issued in 2006.

The licence terms are based on the newly developed Petroleum, Exploration and Production Licence Agreement – PEPLA model. The Company will be able to carry the Prior Sunk cost associated with A4 into the new agreement for tax breaks and enhanced commercial model.

PetroNor will soon commence interpretation on reprocessed seismic data in support of seeking a partner to join the Company in drilling one exploration well in this highly attractive acreage that is on trend with the Sangomar field, 30 km to the North in Senegal. PetroNor aims to participate in any future well at an equity level of 30-50% and is seeking partners to help test the exciting portfolio of potential drilling opportunities.

Senegal

Net working interest
90%

Area
15,796 km^2

Operator
African Petroleum Senegal Ltd

Net unrisked prospective resources (bbl)
1.5 Bn

Licence overview
The Senegal Offshore Sud Profond and Rufisque Offshore Profond licences were awarded to the Company in 2011.

Arbitration proceedings with the International Centre for Settlement of Investment Disputes (ICSID) were registered in July 2018 (case ARB/18/24) to protect PetroNor's interests in the licences.

Between May 2020 and April 2021, the arbitration proceedings were halted to allow discussions between the parties to try and reach a mutually beneficial solution, disappointingly to no avail.

The Company remains confident in its legal position and will progress the arbitration proceedings to an independent judgement.

Knut Søvold
Chief Executive Officer

We delivered a number of transformative events that leave the Company exceptionally well placed to achieve its long-term objectives

PetroNor delivered a resilient performance in what was an unprecedented period for the sector and the global economies as a result of the COVID-19 pandemic. The sudden impact of the pandemic on global demand, and therefore commodity pricing, was both rapid and severe. However, the Company took swift and appropriate action to control costs and has subsequently emerged in robust health. Pleasingly, the sector has rebounded quickly which has enhanced the economics of our production, and also improved the general industry and investor sentiment. In this context, post period, we delivered a number of transformative events, as set out below, that leave the Company exceptionally well placed to achieve its long-term objectives.

The Company moved quickly to capitalise on the improving backdrop, and in the recent months announced a series of transformative corporate events that saw us increase our interest in our cornerstone asset in Congo and strengthen the balance sheet. The acquisition of an additional interest in PNGF Sud is accretive on every metric, enhancing our production, cash flow and reserves.

The associated fundraise in Q1-2021 also ensures the Company is fully-funded for its share of the infill drilling programme in PNGF Sud that will take place in the next 12 months, the successful execution of which will materially enhance our production and cash flow further. The PNGF Sud asset has been the bedrock of our company, and will continue to be so for many years to come given the independently verified upside that remains in the field.

The CPR issued by AGR Petroleum Services in March 2021 demonstrated the continued strong performance of this high quality and economically robust asset, and emphasised the significant value yet to be realised, with PetroNor's net working interest 2P Reserves amounting to 20.23 MMbbl with 2C contingent resources of 7.3 MMbbl (position after aqusition of additional interest). The update represents an increase of approximately 28% and 49% for 2P and 2C respectively on a gross basis, and a 2P reserves replacement for 2020 of over 300%. The Operator Perenco has done an exceptional job of building out the production to bring new life to the asset, and we look forward to benefiting from the continued success of this asset with a more meaningful interest going forward.

In 2020 PetroNor made significant progress in a number of strategic areas as we sought to further diversify the portfolio in line with our strategic vision of establishing the Company as a leading, full-cycle, Pan-African Operator. The addition of high potential acreage in Guinea-Bissau will deliver more high impact assets to our portfolio when that transaction completes, and will enhance our ability to monetise our exploration assets in due course.

We were also pleased to reach a settlement with regards to our long-running arbitration with The Gambia which saw PetroNor regaining the A4 block; a highly prospective block in one of the most exciting hydrocarbon basins in the world. The terms of the new license are significantly more attractive and will enhance not only the value of the license but also its attractiveness to potential partners. This was a positive outcome for the Company and its shareholders, and justified the efforts of the Company to instigate arbitration and to pursue a settlement.

Throughout last year and Q1 of this year, the Company continued to engage with the Senegal authorities to establish a similarly positive outcome, and while progress was made in the year

We believe that it is a very opportunity rich market for a company like PetroNor, and we have every confidence that we can achieve scale through organic and inorganic means.

as both parties agreed to pause the arbitration proceedings with a view to seek an out of court settlement, no such agreement has been made and the process has recently returned to arbitration. The Company remains open to re-initiation of negotiations, however equally remains confident in its legal position and looks forward to seeing the case resolved through independent channels.

The strategy to establish a portfolio of exploration assets in West Africa with high working interests is designed to provide PetroNor with optionality to monetise its early mover advantage with regards to these high-impact assets. These assets are far from wildcat, but rather well progressed assets with numerous drill ready prospects and leads, in a region that continues to see strong industry interest.

Whilst the industry has undoubtedly changed as a result of the Energy Transition and certain majors are shifting focus away from exploration as a result of ESG pressures, we continue to see strong interest in high quality assets and feel confident that we can monetise these assets over time, whilst retaining exposure to exciting drill-bit led value catalysts.

While the Company continues to progress its monetisation strategy of its exploration portfolio, it will continue to explore other opportunities in line with its diversification strategy.

The previously announced transaction with Panoro to farm into the Aje development in Nigeria has been frustratingly delayed as a result of the pandemic, but we expect to see that complete this year, and much work has taken place to work up the re-development concept so that work can commence swiftly following final ratification of that transaction.

The theme of the Energy Transition has gained momentum through the last year, and this is a theme that the Board of PetroNor wholly embraces given the risks that climate change poses to all humanity. In Africa however, the Transition poses its very own immediate risk to the environmental and socioeconomic development of the countries, and people, that rely on the revenue from its discovered resources.

It is well known that many hundreds of millions of Africans do not have access to reliable electricity and the continent will not be transitioning to a greener economy at the same pace as more developed nations. As such, we believe that it is the moral obligation of credible operators such as PetroNor to play its role in enabling a smooth and steady transition that enables the continent to continue to benefit from its natural resources until a more viable and sustainable solution is ready.

The Transition presents PetroNor with a strong opportunity, as IOCs and Majors divest mid-to-later life assets in order to meet their carbon reduction targets. Given our strong network and growing reputation as a credible and responsible operator, we are positioning ourselves as a consolidator of choice, and will be engaging with Governments and IOCs to see how we can help them deliver their respective agendas. Through 2020 and this current year, our business development team has been screening opportunities of various sizes in line with our strategic intent, and hope to deliver more value accretive inorganic growth in the coming years, and achieve the scale that makes us more relevant and more capable of generating sustainable shareholder returns.

ESG is also a growing theme as investors rightly scrutinise companies in detail regarding the way in which they run their business and manage the impact of their activities and the risks that they pose. The Company has always operated with a mindset of sustainability and seeks to ensure positive socioeconomic impact from its activities.

The Company has also made significant efforts to enhance its Governance through the year, reconstituting the Board with a stronger focus on independence. In February of this year, we announced that my co-founder of the business, Mr. Gerhard Ludvigsen, was departing his role on the Board and Executive team, but will continue to provide support to the Company on an ongoing consultancy basis, with a particular emphasis on developing PetroNor's ESG agenda.

The appointment of Mrs. Gro Kielland, a highly credible industry figure, was a demonstration of our growing industry credibility and ambitious intent. In early 2020, we also announced the change of CEO, with Mr. Jens Pace moving to a Non-Executive role, and myself taking over. We believe that PetroNor has assembled a highly experienced, dynamic and ambitious team, with a diverse technical and commercial skillset, capable of delivering long-term value for our shareholders.

This year, we hope to build on the momentum we have already achieved, and deliver a number of material corporate and operational milestones. We believe that it is a very opportunity rich market for a company like PetroNor, and we have every confidence that we can achieve scale through organic and inorganic means. Specifically, we are happy to have concluded the Guinea-Bissau transaction and hope to conclude our previously announced transaction in Nigeria, and make positive headway in monetizing the exploration portfolio that we have assembled. We also look forward to the infill drilling programme on PNGF Sud, and the step-change in production and cash flow that will bring to the Company following completion of the recently announced transaction.

In summary, 2020 was a challenging yet strategically transformational year for PetroNor and the Company is well placed to benefit from an improving industry backdrop and a growing pipeline of compelling and strategically complementary opportunities presenting themselves as a result of the structural changes happening in the sector. The Company has established a diverse portfolio of assets delivering robust cash flow and extraordinary upside potential, and we remain focused on delivering sustainable shareholder value as we progress our strategic and operational initiatives through this year and beyond.

Sincerely,
Knut Søvold
Chief Executive Officer

Introduction

PetroNor's classification of reserves and resources complies with the guidelines established by the Oslo Stock Exchange and are based on the definitions set by the Petroleum Resources Management System (PRMS-2007), sponsored by the Society of Petroleum Engineers/ World Petroleum Council/ American Association of Petroleum Geologists/Society of Petroleum Evaluation Engineers (SPE/PRMS) from 2007 and 2011.

Reserves are the volume of hydrocarbons that are expected to be produced from known accumulations:

- On Production
- Approved for Development
- Justified for Development

Reserves are also classified according to the associated risks and probability that the reserves will be produced.

1P Proved reserves represent volumes that will be recovered with 90% probability

2P Proved + Probable represent volumes that will be recovered with 50% probability

3P Proved + Probable + Possible volumes that will be recovered with 10% probability.

Contingent Resources are the volumes of hydrocarbons expected to be produced from known accumulations:

- In planning phase
- Where development is likely
- Where development is unlikely with present basic assumptions
- Under evaluation

Contingent Resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves.

Disclaimer

the information provided in this report reflects reservoir assessments, which in general must be recognized as subjective processes of estimating hydrocarbon volumes that cannot be measured in an exact way.

It should also be recognized that results of recent and future drilling, testing, production, and new technology applications may justify revisions that could be material. Certain assumptions on the future beyond PetroNor's control have been made. These include assumptions made regarding market variations affecting both product prices and investment levels. As a result, actual developments may deviate materially from what is stated in this report.

The estimates in this report are based on third party assessments prepared by AGR Petroleum Services AS ("AGR") in March 2021 for PNGF Sud and PNGF Bis.

PetroNor assets portfolio

PetroNor's assets are located approximately 25 km off the coast of Pointe Noire in water depths of 80-100 metres. PetroNor, through Hemla E&P Congo S.A. (HEPCO), participated in the 2016 tender process with the Ministry of Petroleum of the Republic of Congo for participation in the PNGF Sud licence (brown field). HEPCO was awarded a 20% working interest in the PNGF Sud licence, corresponding to a net 10.5% to PetroNor. Furthermore, the licence partnership has, through an umbrella agreement, the right to negotiate, in good faith, the licence terms of the adjacent PNGF Bis licence, where Perenco is intended to be operator. The umbrella agreement assigns a 28% HEPCO share to PNGF Bis, yielding a PetroNor 14.7% interest in PNGF Bis.

During 2019, PetroNor made an acquisition of a nominal 6.5% interest in OML-113 (Aje) in Nigeria from Panoro Energy ASA ("Panoro"). An agreement was also made between PetroNor and Yinka Folawiyo Petroleum ("YFP") to jointly further develop OML-113. These agreements are described in further detail in the Director's report. This transaction is not yet completed and is not part of this ASR statement.

The exploration assets in Guinea-Bissau, The Gambia and Senegal only constitute prospective resources, therefore are not considered part of this Annual Statement of Reserves ("ASR").

PNGF Sud

Offshore Congo Brazzaville, operator Perenco, PetroNor 10.5%.

PNGF Sud is a development and exploitation license covering an area containing several oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi fields. The interest in PNGF Sud is held directly by HEPCO with a 20% share. Through PetroNor's ownership of 52.5% of HEPCO, this constitutes an indirect 10.5% share in the PNGF Sud licenses. The ownership of the licences has been effective since 1 January 2017 with an expiry date after 20 years plus a 5-year extension period. Since granting of the licenses, Perenco, with partner support has been committed to strict HSE compliance while growing production, improving maintenance routines and field integrity in a stepwise and prudent manner.

In March 2021 AGR performed a full Competent Persons Report ("CPR") covering the Reserves (1P, 2P and 3P) and Resources (1C, 2C and 3C) in both PNGF Sud and PNGF Bis. The above figures were evaluated as of 31 December 2020.

Gross production during 2020 was 8.31 MMbbls of oil and 1.0 Bcf of gas. This corresponds to average 22,713 bopd and 2.7 mmscfd.

As per the PRMS/SPE guidelines, only a portion of gas is contributing to power generation (on Tchibouela only) and is included in the overall reserves in the AGR CPR. The gas is being used centrally in the field complex as fuel for power generating turbines which is subsequently transmitted to the individual field platforms via electrical power cables. For the purpose of this report, the numbers quoted below as MMbbls do not include the oil equivalent gas but are included in the appendix reserves and resource tables.

This PetroNor ASR uses as the basis the Reserves and Resources from the March 2021 AGR CPR yielding Reserves and Resources as per 31 December 2020. As the only product sold is oil, PetroNor will, in the text below, when referring to Reserves and Resources mainly refer to oil and term these with the unit MMbbls.

As at 31 December 2020, AGR evaluated that gross 1P Proved Reserves yield 86.20 MMbbls in all of the PNGF Sud fields in the Cenomanian, Turonian, Senonian and Albian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 120.2 MMbbls in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 152.4 MMbbls.

Gross 1C Resources yield 26.0 MMbbls in all of the PNGF Sud fields in the Cenomanian, Turonian, Senonian and Albian reservoirs. Gross 2C Resources at PNGF Sud amounted to 43.4 MMbbls in the same reservoirs. Gross 3C Resources at PNGF Sud amounted to 74.6 MMbbls.

These evaluations yield 1P Proved Reserves net to PetroNor of 9.05 MMbbls, 2P Proved plus Probable Reserves net to PetroNor of 12.62 MMbbls and 3P Proved plus Probable plus Possible Reserves net to PetroNor of 16.00 MMbbls.

Additional potentially recoverable resources net to PetroNor are approximately 2.7 MMbbls 1C, 4.6 MMbbls 2C and 7.8 MMbbls 3C.

These Reserves and Contingent Resources are PetroNor's net volumes before deductions for royalties and other taxes, reflecting the production and cost sharing agreements that govern the assets.

PNGF Bis

Offshore Congo Brazzaville, operator Perenco, PetroNor 14.7%.

The PNGF Bis license neighbours the PNGF Sud licences and contains two discoveries, Louissima and Loussima SW. The two discoveries are proven by three wells including DST's drilled from 1985-1991. The primary potential is identified in the pre-salt Vanji formation with promising DST rates, but the exploration and appraisal wells also include an oil column in the post-salt Senji fm (not tested). A long-term test production period with a rented jack-up with a purchase option and an 11 km pipeline tie-back to one of the existing Tchibouela wellhead platforms is a likely scenario. This allows cost recovery of the investments during the test production and allows upscaling the production levels with additional producers as resources are matured to reserves.

Net to PetroNor 1C Contingent Resources yield 3.29 MMbbls in the Loussima SW Vanji and Senji fm. Net 2C at PNGF Bis Loussima SW amounts to 4.25 MMbbls in the same reservoirs. Net 3C amounts to 5.26 MMbbls.

Management discussion and analysis

PetroNor uses the services of AGR Petroleum Services for 3rd party verifications of its reserves and resources.

All evaluations are based on standard industry practice and methodology for production decline analysis and reservoir modelling based on geological and geophysical analysis. The following discussions are a comparison of the volumes reported in previous reports, along with a discussion of the consequences for the year-end 2020 ASR.

PNGF Sud

During all the years from 2017 to 2020, production levels have grown from the initial c. 15,000 bopd when Perenco and partners took over. This has materialized through revitalizing existing producers via replacements or upsizing of Electrical Submersible Pumps ("ESPs"), acidizing, clean up or reperforating wells or converting wells from the Cenomanian to the Turonian (less depleted) formations. Significant surface debottlenecking is also taking place, projects ranging from improved power generation, gas-lift compressor upgrades, pump replacements and other surface process improvements. Production from Tchibeli has been routed to Tchendo by installing a new pipeline to avoid third party processing tariffs previously paid to the Nkossa FPSO. These brick-by-brick improvements have yielded a production level during 2020 of 22,713 bopd. The production improvements alone have yielded more than a 100% reserves replacement each year at a cost of less than 1 USD/bbl. In addition to this, significant infill drilling potential has been identified in all fields and justified for investment, so far in three of these, the Litanzi, Tchendo and Tchibeli.

The start of infill drilling has in 2020-2021 been delayed by COVID-19, however, significant investments have already been made in infill drilling infrastructure to accommodate offtake, process and well slots. An infill drilling program was decided for the Litanzi field in 2019 and in 2020 for Tchendo and Tchibeli. Consequently the 2C resources in these fields have been converted to 2P reserves. Development of 3D static and dynamic models has been and will continue to form the basis of further infill drilling programmes on PNGF Sud. In recognition of the infill potential existing on Tchibouela there has been an increase also in the 2C resources in this field.

In summary for all fields, the conversion of 2C to 2P and the increase in 2P reserves between 2019 and 2020 constitutes 26.0 MMbbls. This corresponds to a 2P increase of 28%. With gross produced volumes during 2020 of 8.3 MMbbls, this represents a reserve replacement ratio of 313%. Additionally, the increase in 2C resources is 14.2 MMbbls, primarily reflecting the further infill potential in Tchibouela.

PNGF Bis

Once investment decisions are made on the Loussima SW project these reserves may become reserves approved for development. The 2C resources in PNGF Bis have been reaffirmed by AGR as part of this years' reserves and resource audit without change to the numbers. It is expected that these discoveries will have priority following the infill drilling programmes in PNGF Sud. Given a successful Loussima SW, a similar development potential is also likely for the Loussima Discovery.

Assumptions

The commerciality and economic tests for the PNGF Sud and Bis reserves volumes were based on an oil and condensate price of 60 USD/bbl, although the reserves and resources are not very sensitive to this parameter as OPEX levels in 2020 were at 10.4 USD/bbl.

2020 – 2P Reserves	(MMbbls)
Balance (gross AGR, PNGF Sud – 31.12.2020)	120.2
Balance 31.12.2020 – 2P net, PNGF Sud	12.6

2P and 2C Reserves and Resources Status	(MMbbls)
Balance 31.12.2020 – 2P/2C gross, PNGF Sud	163.6
Balance 31.12.2020 – 2P/2C net, PNGF Sud	17.2
Balance 31.12.2020 – 2P/2C gross, Sud+Bis	192.5
Balance 31.12.2020 – 2P/2C net, Sud+Bis	21.4

PetroNor's total 1P Reserves at end of 2020 amounted to 9.05 MMbbls. PetroNor's 2P Reserves amount to 12.62 MMbbls and PetroNor's 3P Reserves amount to 16.00 MMbbls. This reflects the March 2021 reserve report for the PNGF Sud field, conducted by AGR Petroleum Services AS and production since the field start-up.

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By end of 2020, PetroNor's assets contain a total 2C volume of approximately 8.8 MMbbls.

29 April 2021
Knut Søvold
Chief Executive Officer

Reserves and resources as per 31 December 2020 (AGR CPR dated 10 March 2021)

Gross Reserves (developed or under development)

	1P			2P			3P		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
100% PNGF Sud									
Tchibouela	50.80	11.90	52.90	62.80	16.90	65.80	76.40	25.40	80.90
Tchendo	21.10	–	21.10	28.90	–	28.90	36.00	–	36.00
Tchibeli	7.40	–	7.40	17.70	–	17.70	26.50	–	26.50
Litanzi	6.90	–	6.90	10.80	–	10.80	13.50	–	13.50
Subtotal	**86.20**	**11.90**	**88.30**	**120.20**	**16.90**	**123.20**	**152.40**	**25.40**	**156.90**
100% PNGF Bis									
Loussima (Bis)	–	–	–	–	–	–	–	–	–
Total	86.20	11.90	88.30	120.20	16.90	123.20	152.40	25.40	156.90

Gross Contingent Resources (undeveloped)

	1C			2C			3C		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
100% PNGF Sud									
Tchibouela	14.70	8.90	16.30	23.10	13.80	25.50	37.40	22.30	41.30
Tchendo	5.40	–	5.40	9.10	–	9.10	19.20	–	19.20
Tchibeli	5.90	–	5.90	11.20	–	11.20	18.00	–	18.00
Litanzi	–	–	–	–	–	–	–	–	–
Subtotal	**26.00**	**8.90**	**27.60**	**43.40**	**13.80**	**45.80**	**74.60**	**22.30**	**78.50**
100% PNGF Bis									
Loussima (Bis)	22.40	–	22.40	28.90	–	28.90	35.80	–	35.80
Total	**48.40**	**8.90**	**50.00**	**72.30**	**13.80**	**74.70**	**110.40**	**22.30**	**114.30**

Net to PetroNor - Reserves and resources as per 31 December 2020 (AGR CPR dated 10 March 2021)
Reserves are shown according to the ownership in PNGF Sud as of 31 December 2020, the subsequent change in owernship in PNGF Sud from 10.5% to 16.83% is not reflected in the tables below.

Net PetroNor Reserves (developed or under development)

	1P			2P			3P		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
10.50% PNGF Sud									
Tchibouela	5.33	1.25	5.55	6.59	1.77	6.91	8.02	2.67	8.49
Tchendo	2.22	–	2.22	3.03	–	3.03	3.78	–	3.78
Tchibeli	0.78	–	0.78	1.86	–	1.86	2.78	–	2.78
Litanzi	0.72	–	0.72	1.13	–	1.13	1.42	–	1.42
Subtotal	**9.05**	**1.25**	**9.27**	**12.62**	**1.77**	**12.94**	**16.00**	**2.67**	**16.47**
14.70% PNGF Bis									
Loussima (Bis)	–	–	–	–	–	–	–	–	–
Total	**9.05**	**1.25**	**9.27**	**12.62**	**1.77**	**12.94**	**16.00**	**2.67**	**16.47**

Net PetroNor Contingent Resources (undeveloped)

	1C			2C			3C		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
10.50% PNGF Sud									
Tchibouela	1.54	0.93	1.71	2.43	1.45	2.68	3.93	2.34	4.34
Tchendo	0.57	–	0.57	0.96	–	0.96	2.02	–	2.02
Tchibeli	0.62	–	0.62	1.18	–	1.18	1.89	–	1.89
Litanzi	–	–	–	–	–	–	–	–	–
Subtotal	**2.73**	**0.93**	**2.90**	**4.56**	**1.45**	**4.81**	**7.83**	**2.34**	**8.24**
14.70% PNGF Bis									
Loussima (Bis)	3.29	–	3.29	4.25	–	4.25	5.26	–	5.26
Total	**6.02**	**0.93**	**6.19**	**8.81**	**1.45**	**9.06**	**13.10**	**2.34**	**13.51**

Pro forma net to PetroNor - Reserves and resources as per 31 December 2020
Reserves are shown according to the ownership in PNGF Sud on a pro forma basis assuming the increase in ownership has taken place as of 31 December 2020

Net PetroNor Reserves (developed or under development)

	1P			2P			3P		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
16.83% PNGF Sud									
Tchibouela	8.55	2.00	8.90	10.57	2.84	11.07	12.86	4.27	13.62
Tchendo	3.55	–	3.55	4.86	–	4.86	6.06	–	6.06
Tchibeli	1.25	–	1.25	2.98	–	2.98	4.46	–	4.46
Litanzi	1.16	–	1.16	1.82	–	1.82	2.27	–	2.27
Subtotal	**14.51**	**2.00**	**14.86**	**20.23**	**2.84**	**20.73**	**25.65**	**4.27**	**26.41**
23.6% PNGF Bis									
Loussima (Bis)	–	–	–	–	–	–	–	–	–
Total	**14.51**	**2.00**	**14.86**	**20.23**	**2.84**	**20.73**	**25.65**	**4.27**	**26.41**

Net PetroNor Contingent Resources (undeveloped)

	1C			2C			3C		
	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe	Oil MMbbl	Gas bcf	Boe mmboe
16.83% PNGF Sud									
Tchibouela	2.47	1.50	2.74	3.89	2.32	4.29	6.29	3.75	6.95
Tchendo	0.91	–	0.91	1.53	–	1.53	3.23	–	3.23
Tchibeli	0.99	–	0.99	1.88	–	1.88	3.03	–	3.03
Litanzi	–	–	–	–	–	–	–	–	–
Subtotal	**4.38**	**1.50**	**4.65**	**7.30**	**2.32**	**7.71**	**12.56**	**3.75**	**13.21**
23.6% PNGF Bis									
Loussima (Bis)	5.29	–	5.29	6.82	–	6.82	8.45	–	8.45
Total	**9.66**	**1.50**	**9.93**	**14.12**	**2.32**	**14.53**	**21.00**	**3.75**	**21.66**

Responsible business

By embracing the growing awareness of ESG, PetroNor E&P is committing to operating responsibly. Having local management on the ground in our countries of operation is an important part of anchoring our activities to the local society and that the company is well suited to support local growth with our projects.

Environmental

PetroNor strives that our operations minimise any adverse impact on the environment and is fully committed to environmental stewardship.

As an integral part of any development, we always undertake Environmental Impact Assessments ("EIA") prior to all major activities & communicate results to stakeholders.

The Aje project in Nigeria will provide cleaner fuel to a region which is hungering for energy. Our plans for the Aje redevelopment will provide low emission energy corresponding to 5% of the total power production of Nigeria.

The Aje gas development will lead to displacement of gasoline used for power generation in Lagos.

Social

During the last few years, we have set aside 5% of our net profits in Congo Brazzaville towards social programs.

A key focus has been on education, as shown in our case example: the Power to Educate initiative is focused on improving conditions for families in areas with no access to electricity.

Other projects include human capacity development and access to quality health care.

Governance

In 2020 PetroNor joined the Extractive Industries Transparency Initiative.

With an open business model, PetroNor aims to increase access to opportunities for local growth through the formation of subsidiary companies with indigenous partners.

Our company is continuously working towards diversification both at board level and in the organisation.

According to United Nations, of all regions in the world, sub-Saharan Africa has the highest rates of education exclusion. Over one-fifth of children between the ages of about 6 and 11 are out of school, followed by one-third of youth between the ages of about 12 and 14. According to UIS data, almost 60% of youth between the ages of about 15 and 17 are not in school.

Locations of our six supported elemenary schools

Elementary schools in Congo Brazzaville

Our company is engaged in a number of developing countries in Africa. We see education as a strong driver for development across the continent where continued support and strengthening of elementary education is still in need. Our group has supported construction of six elementary schools in the Republic of Congo in 2019 and 2020. The school buildings are equipped with electrical light and clean water. Our hope is that our contribution can be one of many.

As a company we appreciate that education is an important factor for growth in any society.

The Board

Eyas Alhomouz
Non-Executive Director and Chairman

Qualifications
Mr. Alhomouz graduated from Brigham Young University in Provo, Utah with a degree in Chemical Engineering and from the Colorado School of Mines, in Golden, Colorado with a master's degree in Mineral and Energy Economics.

Experience
Mr. Alhomouz has a strong experience from the oil and gas sector covering the United States, North Africa, and the GCC. He began his career with Schlumberger Oilfield Service as a wireline engineer in Midland, Texas. From there he went on to work for Cromwell Energy in Denver, Colorado, in the role of international business development manager. Then, as chief operating officer and finance director of Prism Seismic, he oversaw the growth of the Colorado based consulting and oil and gas software development firm, and later the acquisition of the company by Sigma Cubed where, post-acquisition of Prism Seismic, he went on to serve as a director of business development, Middle East. Mr. Alhomouz's career then took him to Qatar as general manager of Jaidah Energy, an Omani-Qatari owned company servicing the oil and gas sector in Qatar.

CEO of Petromal LLC a subsidiary of National Holding in Abu Dhabi.

Joseph Iskander
Non-Executive Director

Qualifications
Mr. Iskander holds a Degree in Accounting and Finance with high distinction from Helwan University, Egypt.

Experience
Mr. Iskander brings over 20 years of experience in the financial services industry, covering asset management, private equity, portfolio management, financial restructuring, research, banking, and audit. He began his career at Deloitte & Touche (Egypt) as an Auditor. Mr. Iskander served as non-executive director on the boards of EFG Hermes in Egypt, Oasis Capital Bank in Bahrain, Sun Hung Kai & Co. in Hong Kong, Qalaa Holdings in Egypt, Emirates Retakaful in UAE, Marfin Laiki Bank in Cyprus and Marfin Investment Group in Greece. Mr. Iskander headed the research team at Egypt's Prime Investments and was earlier an investment advisor at Commercial International Bank (CIB). He then went on and joined Dubai Group as an investment manager in 2004 and has worked on a range of M&A transactions, advisory services, asset management, and private equity transactions with a collective value in excess of USD 8 billion. Mr. Iskander was managing director of Asset Management at Dubai Group and the former head of research at Dubai Capital Group until 2009. He joined Emirates International Investment Company in July of 2017 as the director of private equity spearheading and managing EIIC's investments.

EIIC is a subsidiary of National Holding in Abu Dhabi.

Jens Pace
Non-Executive Director

Qualifications
Mr. Pace holds a BSc in Geology and Oceanography from the University of Wales and a MSc in Geophysics from Imperial College, London, UK.

Experience
Mr. Pace is a highly regarded geoscientist, who has had a successful career at BP Exploration Operating Company Limited ("BP"), and its heritage company Amoco (UK) Exploration Company. Mr. Pace has held senior positions at BP for over 10 years, gaining exploration and production experience in Africa, namely: Algeria, Angola, Congo, Gabon and Libya. In addition, he has experience in Europe, Russia and Trinidad. He has contributed to a number of BP's exploration discoveries over his career, and has managed a very large and active exploration portfolio for BP in Africa. Additionally, Mr. Pace has gained highly sought-after experience in the areas of field development and as a commercial manager, dealing with national oil companies and African governments.

Following the merger with PetroNor E&P Ltd on 30 August 2019, Mr. Pace resigned as Chief Executive Office on 29 February 2020, but remains on the Board as a Non-Executive Director.

A diverse and experienced team

Ingvil Smines Tybring-Gjedde
Non-Executive Director

Qualifications
Mrs. Smines Tybring-Gjedde graduated from BI Norwegian Business School with a Masters degree in Management Programs, with strong focus on Interaction and Leadership and Strategy.

Experience
Experienced former Norwegian Minister of National Public Security with overall responsibility of public safety, emergency planning, and cybersecurity. Mrs. Tybring-Gjedde was also Minister of Svalbard and the Norwegian polar regions. Before her position as Minister, she served as Deputy Minister in the Ministry of Petroleum and Energy for 4 years, with a portfolio of exploration policy, development, and operations, exploration activity as well as following the Ministry's contact with other petroleum-producing countries and international forums in addition to the government's national climate policy, global environmental issues and the government's CCs full-scale project. Mrs. Tybring-Gjedde has a demonstrated history of working in the O&G, energy, and renewable industry in private and state-owned companies in various leading positions for more than 20 years.

Gro Kielland
Non-Executive Director

Qualifications
Mrs. Kielland holds an MSc in Mechanical Engineering from the Norwegian University of Science and Technology (NTNU).

Experience
Mrs. Kielland has over 30 years of experience having held a number of leading positions in the oil and gas industry both in Norway and abroad, among others as CEO of BP Norway. Her professional experience includes work related to both operations and field development, as well as HSE.

Roger Steinepreis
Non-Executive Director

Qualifications
Mr. Steinepreis holds a Bachelor of Jurisprudence and Bachelor of Laws (1985) from the University of Western Australia.

Experience
Mr. Steinepreis is a corporate and resources lawyer with over 30 years' experience. He has acted as the legal adviser on in excess of 40 initial public offers and has advised numerous companies, large and small, on strategic acquisitions, whether by takeover, scheme of arrangement, trade sale or other means.
Mr. Steinepreis serves as the executive chairman of Steinepreis Paganin, one of the largest, specialist corporate law firms in Perth, Australia, and serves on other boards.

Alexander Neuling
Non-Executive Director

Qualifications
Mr. Neuling holds a BSc (Hons) in Chemistry from Leeds University, United Kingdom and he is a Fellow of the Institute of Chartered Secretaries and Administrators and a Fellow of the Institute of Chartered Accountants of England & Wales.

Experience
Mr. Neuling is a chartered accountant and has been advising within extractive industries for more than 15 years. Mr. Neuling has held numerous senior management positions at listed companies, and previously worked for Deloitte in London and Perth.

Senior Management

Knut Søvold
Executive Director and Chief Executive Officer

Qualifications
Mr. Søvold holds a MSc in Petroleum from The Institute of Technology in Trondheim (NTH), Norway.

Experience
Mr. Søvold has 30 years of experience in the oil and gas industry, from both executive management and technical levels. His extensive experience covers fields and licenses in the North Sea, North and West Africa, Middle East, Far East and FSU, as well as management and administration through establishing and operating companies in Norway, UK, Kazakhstan and West Africa. Mr. Søvold was in the management team of the Snorre Field in the North Sea, with a production of 200,000 bopd. Mr. Søvold has been working with West African assets since 2000 and in Nigeria since 2008. Furthermore, he has also been working with gas to LNG, including novel solutions such as FLNG, gas to power, as well as LNG-regasification.

Mr. Søvold is a founding member of PetroNor.

Claus Frimann-Dahl
Chief Technical Officer

Qualifications
Mr. Frimann-Dahl holds a BSc in Petroleum Engineering from Texas A&M University and an MSc from the University of Trondheim (NTH).

Experience
Mr. Frimann-Dahl has 30 years' experience from the oil and gas industry, with managerial and technical roles. His experience covers operational roles with Phillips Petroleum, Norsk Hydro and Hess in the North Sea Norway and Denmark, Russia, Egypt and the US. He was the co-founder of Ener Petroleum which was later acquired by Dana Petroleum and KNOC.

Michael Barrett
Exploration Manager

Qualifications
Mr. Barrett holds a BSc in Geology & Geophysics from Durham University and a MSc in Petroleum Geology & Geophysics from Imperial College, Royal School of Mines.

Experience
Mr. Barrett has 30 years of global exploration experience from his career at Chevron Corporation, and more recently with an Africa specific focus at Addax/Sinopec International and African Petroleum. Mr. Barrett has held a variety of senior technical roles covering exploration and new ventures, and was part of Chevron's global Exploration Review Team, specialising in Play and Prospect risk and volumetric assessment. He has extensive experience in portfolio management and commercial evaluation of oil and gas opportunities.

Emad Sultan
Strategy and Contracts Manager

Qualifications
Mr. Sultan holds a BSc in Mechanical Engineering from the University of Washington.

Experience
Mr. Sultan has 20 years of international Exploration & Production experience. He has held multiple operation and marketing management positions with international oil field services companies. He has also worked in a number of technical, contracting and strategy management roles with major oil and gas operators.

Chris Butler
Group Financial Controller

Qualifications
Mr. Butler is a Fellow of the Institute of Chartered Accountants in England and Wales and holds a BSc in Physics from Warwick University, UK.

Experience
Mr. Butler has 16 years of financial and corporate experience from positions in public practice, oil & gas and mining spread over Africa, Asia and Europe, with roles that included financial reporting, contract negotiations, M&A, due diligence, treasury and several system implementations.

Angeline Hicks
Company Secretary

Qualifications
Chartered Accountant

Experience
After gaining her qualifications at Deloitte, Ms. Hicks furthered her career in the banking industry in London for eight years, working for investment banks such as Barclays Capital, Credit Suisse and JP Morgan, focusing on managing compliance and corporate and financial reporting. Ms. Hicks is an Associate of the Governance Institute of Australia and also performs the role of Company Secretary for companies listed on the Australian Securities Exchange.

The Directors present their report on PetroNor E&P Limited ("PetroNor" or the "Company") for the year ended 31 December 2020.

Directors & Company Secretary

The names of Directors in office during the financial year and until the date of this report are as follows. Directors were in office for this entire period unless otherwise stated.

	Role	Appointed	Resigned
Current members:			
E Alhomouz	Non-Executive Chairman	-	-
J Iskander	Non-Executive Director	-	-
J Pace	Executive Director Chief Executive Officer	-	29 Feb 2020
	Non-Executive Director	01 Mar 2020	-
A Neuling	Non-Executive Director	06 Apr 2020	-
R Steinepreis	Non-Executive Director	06 Apr 2020	-
I Tybring-Gjedde	Non-Executive Director	29 May 2020	-
G Kielland	Non-Executive Director	01 Feb 2021	-
A Hicks	Company Secretary	-	-
Former members:			
K Søvold	Executive Director	-	29 May 2020
	Chief Executive Officer	29 Feb 2020	-
G Ludvigsen	Executive Director	29 May 2020	31 Jan 2021
S West	Executive Director	-	29 Feb 2020
T Turner	Non-Executive Director	-	08 Feb 2020
D King	Non-Executive Director	-	01 Feb 2020

Principal Activity

The Company's principal activity during the year was oil and gas exploration and production.

Review of Operations
Corporate

Board Appointments & Resignations

After the successful integration of the Company and African Petroleum Corporation Ltd in 2019, three of the former Directors from African Petroleum resigned during February 2020 to streamline the Board and management structure. At the same time, Knut Søvold was promoted internally to the position of Chief Executive Officer, having been a founding member of PetroNor, whereas former African Petroleum CEO, Jens Pace, stepped down from the role but continues to serve the Company as a Non-Executive Director.

After the AGM on 29 May 2020, Gerhard Ludvigsen and Ingvil Smines Tybring-Gjedde were formally appointed to the Board of Directors. However, with the stated aims to adopt more standard Norwegian governance procedures, Knut Søvold relinquished his position on the Board of Directors and continues to serve as CEO of the Company.

On 1 February 2021, Gro Kielland was appointed as an Independent Director to replace Executive Director Gerhard Ludvigsen, to further strengthen the governance procedures.

Gro Kielland is a highly experienced and credible industry figure, having previously been the former CEO of BP Norway, and currently holding a number of non-executive roles, including a role on the Board of AkerBP, a company with a market cap of NOK 85 billion and a production of around 200,000 bopd.

Mr. Ludvigsen relinquished his position on the executive team, however, he remains with the Company in an advisory role with specific focus on the Company's effective ESG strategy.

Following these changes, the Board consists of seven Directors, of which five are considered to be independent.

Free Float & Market Making

Post period, the free float of the Company exceeded 25%, for the first time since the merger with African Petroleum in 2019. The Directors hope to further broaden and diversify its shareholder base with the announced contemplated equity financing event.

In keeping with similar sized companies, the Company commenced a market making agreement with SpareBank 1 Markets AS on 3 November 2020, with the primary purpose of enhancing the liquidity in the trading of the Company's shares listed on Euronext Expand. The agreement was for a 6-month period, and the performance will be evaluated before the Company commits to renewing the agreement.

Corporate Restructuring

The plans previously announced in February 2020, to redomicile the Company to Europe during H2-2020 in order to streamline the corporate structure and reduce corporate overheads have not yet been executed. The entire process is estimated to take 3 months, but this project has been delayed due to COVID-19 and is now expected to take place in Q2-2021.

EITI - Supporting Company

During 2020, the Company became a supporter of the Extractive Industries Transparency Initiative ("EITI"), and thereby wish to promote transparency throughout the extractive industries, help public debate and provide opportunities for sustainable development.

COVID-19

The Company adapted quickly to the limitations on travel due to restrictions on social mobilty imposed by Governments around the world. Plus with additional cost control measures put in place at the outset of the pandemic, the Company managed to continue trading throughout. The overall impact of COVID-19 on the Company is hard to assess, however it has delayed the plans by the Directors to grow the Company since the reverse takeover in 2019 by approximately one year.

Review of Operations
Operational updates

Republic of Congo
PNGF Sud
PNGF Sud fields are located approximately 25 km off the coast of Pointe-Noire in water depths of 80-100 metres. PNGF Sud comprises 3 operating licenses, Tchibouela II, Tchendo II and Tcibeli-Litanzi II, covering five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi. PetroNor, through Hemla E&P Congo S.A., participated in the 2016 tender process with the Congo Ministry of Hydrocarbon for participation in the PNGF Sud licenses. As of 1 of January 2017, Hemla E&P Congo S.A. was awarded a 20% working interest in the PNGF Sud licenses (net 10.5% to PetroNor).

Initially discovered in 1979, PNGF Sud commenced production in 1987 and produces from 65 wells from its five oil fields.

Following the entry of the new license group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bopd in January 2017 to an average production in 2020 of 22,713 bopd. Through further workovers, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from 65 active production wells, with oil exported via the onshore Djeno terminal. With its long production history, substantial well count and extensive infrastructure, PNGF Sud offers well diversified and low risk production and reserves with low break-even cost.

In March 2021, AGR Petroleum prepared a Competent Person's Report whereby the reserves below are calculated to 31 December 2020.

PetroNor's Reserves as at 31 December 2020 were:
- 1P reserves of 9.05 MMbbls.
- 2P reserves of 12.62 MMbbls
- 3P reserves of 16.00 MMbbls.

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By end of 2020, PetroNor's assets contain a total 2C volume of approximately 8.81 MMbbls.

During 2020, the gross production was 8.31 MMbbls of oil and 1.00 Bcf of gas, resulting in a net to PetroNor production of 2,385 bopd.

On 27 October 2020, in relation to a dispute concerning PNGF Sud, the Court of Appeal rejected an appeal against certain shareholders in PetroNor and the subsidiary Hemla Africa Holding AS ("HAH") and the appellant was ordered to cover the costs in connection with the appeal.

Republic of Congo
PNGF Bis
PNGF Bis is located to the North-West of PNGF Sud and comprises 2 discoveries: Loussima SW and Loussima.

Through an umbrella agreement, the license partners of PNGF Sud have the right to negotiate, in good faith, the license terms to enter into a PSC for PNGF Bis.

Three exploration wells have been drilled on this license area. A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Loussima in 1985. Loussima SW was discovered by well LUSOM-1 in 1987 with oil in Vandji Fm.

A second well, SUEM-2, was drilled on Loussima SW in 1991 to appraise the Vandji discovery. Hydrocarbon shows were detected in one of the wells in the Albian post-salt Sendji Fm, (analogue to Tchibeli / Litanzi reservoirs in PNGF Sud). The Sendji interval was not production tested. The depth to the Vandji reservoir is 3,250 mTVDSS, to Sendji around 1,940 mVDSS and the water depth in the area is 110 m. Tests on the Loussima SW LUSOM-1 well produced 4,700 bopd and the SUEM-2 well yielded 1,150 bopd.

The CPR report prepared by AGR estimates that PNGF Bis holds gross 2C resources of 28.90 MMbbl.

The Gambia
A4
During September 2020, the Company reached a mutual agreement with the Government of The Gambia to settle its arbitration related to the A1 and A4 licences. PetroNor relinquished any claims related to the A1 licence and regained the A4 licence with a new 30-year lease under new terms.

The terms of the new licence are based on the newly developed Petroleum, Exploration and Production Licence Agreement - PEPLA model. The Company will be able to carry the Prior Sunk cost associated with A4 into the new agreement for tax breaks and enhanced commercial model.

PetroNor will soon commence interpretation on reprocessed seismic data in support of seeking a partner to join the Company in drilling one exploration well in this highly attractive acreage that is on trend with the Sangomar field, 30 km to the North in Senegal. PetroNor aims to participate in any future well at an equity level of 30-50% and is seeking partners to help test the exciting portfolio of potential drilling opportunities.

Review of Operations
Operational updates

Guinea-Bissau
2 & 4a & 5a

On 20 November 2020, the Company announced the purchase of SPE Guinea Bissau AB from Svenska Petroleum Exploration AB. The transaction received the required in-country approvals published in the Official Gazette of Guinea-Bissau (Boletim Oficial) on 20 April 2021. Subsequently, the Company has assumed the operatorship of the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau.

The licences have been recently extended for 3 years and are valid until 2 October 2023 maintaining the same attractive fiscal terms.

PetroNor intends to build on the excellent work of the previous Operator Svenska Petroleum Exploration Guinea Bissau, and maintain the momentum towards drilling built by the Partnership. The Atum-1x well will test a highly attractive and material prospect on the Sinapa licence, analogous to the Sangomar field in Senegal. Recently reprocessed seismic data will be interpreted as part of the ongoing evaluation of both licences and as preparation to drilling.

Senegal
ROP & SOSP

The Company's subsidiary African Petroleum Senegal Limited registered a request for arbitration proceedings with the International Centre for Settlement of Investment Disputes (ICSID) on 11 July 2018 (case ARB/18/24) to protect its interests in the Senegal Offshore Sud Profond and Rufisque Offshore Profond blocks in Senegal.

In May 2020, the Company agreed with the Government of Senegal to the halt of arbitration proceedings. On 5 April 2021, the Company announced that throughout the prolonged suspension period, the Company has made significant efforts to reach a mutually beneficial solution and has held numerous progressive meetings with the relevant authorities to no avail. While it is disappointing that a settlement could not be reached, the Board and its legal counsel remain wholly confident in PetroNor's legal position and look forward to progressing the Arbitration to an independent judgement.

Nigeria
OML-113 / The Aje Field

On 31 December 2020, PetroNor and Panoro Energy ASA ("Panoro") agreed to extend the completion long stop date for the previously announced purchase of Panoro's fully owned subsidiaries that hold 100% of the shares in Pan Petroleum Aje Limited ("Pan Aje") ("the Transaction"). The original long stop date was 31 December 2020, being the date by which authorisation of the Nigerian Department of Petroleum Resources and the consent of the Nigerian Minister of Petroleum Resources were required to have been received. The amended long stop date to complete the Transaction is now 30 June 2021.

The regulatory approval process in Nigeria is well underway at an advanced stage but has been delayed by the pandemic.

As previously announced, following completion of the Transaction, Panoro's intention is to declare a special dividend and distribute to its shareholders USD 10 million equivalent in PetroNor shares in order for Panoro shareholders to retain a direct listed exposure to Aje/OML-113.

Also in 2019, PetroNor entered into separate agreements with the OML-113 operator Yinka Folawiyo Petroleum ("YFP") to create a holding company to exploit the substantial gas and liquids reserves at Aje. The regulatory process for this agreement is aligned with the Transaction and is expected to be approved concurrently.

PetroNor and Panoro have also taken the opportunity to review the deferred contingent element of the Transaction, reflecting the changed macro-economic background since the original announcement in 2019. Under the original agreement, once PetroNor had recovered all its costs related to their future investments to bring Aje gas into production, the Company was to pay to Panoro additional consideration of USD 0.15 per 1,000 cubic feet of the natural gas sales, such additional consideration being capped at USD 25 million. The amended terms are for the consideration to be USD 0.10 per 1,000 cubic feet with the additional consideration being capped at USD 16.67 million.

PetroNor continued work to update the field development plan ("FDP") to expedite gas development and engaged with potential offtakers and partners. PetroNor will engage the JV partners after DPR approval.

Flare Gas

PetroNor E&P has jointly been working with Aragon (www.aragon.no) on developing a concept to capture flare gas. PetroNor and Aragon will convert pollution into clean energy. Today the world is flaring gas similar to an amount which could power all the cars in Europe or supply the African continent with electricity. Our consortium has been approved in Nigeria and is now in process to qualify for specific projects, PetroNor intends to expand its flare gas division as soon as we have one such project is developed as reference.

Result

The Board of Directors (the "Board") confirms that the annual financial statements have been prepared pursuant to the going concern assumption, and that this assumption was realistic at the balance sheet date. The going concern assumption is based upon the financial position of the Group and the development plans currently in place.

In the Board of Directors' view, the annual financial statements give a true and fair view of the Group's assets and liabilities, financial position and results. PetroNor E&P Limited is the parent company of the PetroNor Group (the "Group"). Its financial statements have been prepared on the assumption that PetroNor will continue as a going concern and the realisation of assets and settlement of debt in normal operations.

The Group had USD 14.1 million in cash and bank balances as of 31 December 2020 (2019: USD 27.9 million).

PetroNor E&P Ltd prepares its financial statements in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report also complies with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

The consolidated financial statements are presented in US dollars.

Financial Performance and Activities

Key Consolidated Income Statement figures

Despite the ongoing impact of the pandemic, the Directors are pleased to report an EBITDA of USD 34.4 million for the year.

The Group managed to generate a net profit for the year of USD 11.2 million. However, the prior year loss was due to the accounting for a USD 19.4 million share-based payment expense in relation to the reverse takeover in August 2019. Once adjusted, the 2019 comparative would be a profit of USD 13.6 million.

These figures are due to the steady oil production of the PNGF Sud during the quarter and throughout the year that have come about from the workover program. In fact, since the Group first entered the licences in 2016, it has seen a 33% increase in the gross field production and the OPEX reduced by 58% from 25.0 USD/bbl to 10.4 USD/bbl in the same timeframe.

During 2020, there were only 7 liftings of oil, with a 12.7% increase on the 880,844 barrels lifted in 2019. Despite the depressed oil prices during 2020, the Group achieved an average selling price of 41 USD/bbl for the year, compared to the 65 USD/bbl in 2019. As a consequence, the group reports USD 67.5 million in revenue, a 34.3% decrease on 2019 USD 102.8 million.

Condensed Consolidated Balance Sheet

As at the year end, the Group reassessed the classification of the USD 21.3 million cash advanced to the Operator in Congo towards the Asset Retirement Obligation ("ARO") as a Non-Current Asset in a change to the presentation on the Q4-2020 interim report. Although in 2019, the contractor group agreed to refund previous surplus cash set aside for the ARO back into the operating cash pool, the current cash projection does not anticipate the same situation in the short term.

With the award of a new licence in The Gambia during the year, the Group has capitalised USD 3.0 million of intangible licence costs in relation to the new licence.

However as the past costs of the former A4 licence are allowed to be carried over to the new licence, the past cost pool far exceeds the carrying value of the asset as at 31 December 2020.

Throughout the year the Group maintained cost discipline, but a direct comparison of the administrative expenses for the Group between 2020 and 2019 is not possible. Due to the merger in August 2019, the 2019 comparative figures include the costs of the merger transaction, and 8 months of the former Cypriot group, whereas 2020 figures portray the costs of the enlarged group, despite significant cutbacks by management on overheads after the initial outbreak of the pandemic in the Spring of 2020.

Key Consolidated Income Statement figures
For the year ended 31 December

	2020 USD'000'000	2019 USD'000'000
Revenue from sales of petroleum products	**40.6**	57.5
Assignment of tax oil	**17.1**	29.9
Assignment of royalties	**9.8**	15.4
Revenue	**67.5**	102.8
EBITDA	**34.4**	49.1
Net profit/(loss)	**11.2**	(5,8)
Quantity of oil lifted (barrels)	**993,574**	880,844
Average selling price (USD/bbl)	**40.90**	65.25
Quantity of net oil produced after royalty, cost oil and tax oil (barrels)	**999,522**	860,769

Condensed Consolidated Balance Sheet
As at 31 December

	2020 USD'000'000	2019 USD'000'000
Current assets	**27.1**	55.9
Non-current assets	**51.9**	27.3
Total assets	**79.0**	83.2
Current liabilities	**26.4**	47.5
Non-current liabilities	**30.3**	14.4
Total liabilities	**56.7**	61.9
NET ASSETS	**22.3**	21.3
Capital and reserves attributable to owners of the parent	**7.9**	6.5
Non-controlling interests	**14.4**	14.7
TOTAL EQUITY	**22.3**	21.3

Allocation of Profits and Losses

Funding

During the year, the Company renegotiated the terms and extended the credit of a short-term debt facility of USD 12.9 million from Rasmala (London and Dubai based investor group). The loan was replaced in May 2020 with a USD 15 Million facility with 12 months grace period and final maturity date in November 2022.

In Q3 2020, subsidiary company Hemla Africa Holding AS paid a USD 3.9 million dividend to minority interest and related party Symero Ltd ("Symero"). An amount equal to the dividend was immediately loaned to the Company by Symero with interest rates matching those already provided by the external financing from Rasamala and no security was provided for the loan. The maturity date is matched to the USD 15 million facilty from Rasmala.

Dividends paid or recommended

During the year no dividend was paid or recommended.

Risk Factors

Operational Risk Factors

The Group participates in oil and gas projects in countries in West Africa with emerging economies, such as Congo Brazzaville, Nigeria, The Gambia, Senegal and Guinea-Bissau.

Oil and gas exploration, development and production activities in such emerging markets are subject to significant political and economic uncertainties that may include, but are not limited to, the risk of war, terrorism, expropriation, nationalization, renegotiation or nullification of existing or future licences and contracts, changes in crude oil or natural gas pricing policies, changes in taxation and fiscal policies, imposition of currency controls and imposition of international sanctions. Travel bans, asset freezes or other sanctions may be imposed and have historically been imposed on countries in which the Group operates.

The Group has operations in countries with a low score on Transparency International's Corruption Perception Index, which implies that these countries are perceived as jurisdictions where there is a higher risk of corruption. Corrupt practices of third parties or anyone working for the Group or any of its affiliated parties, or allegations of such practices, may have a material adverse effect on the reputation, performance, financial condition, cash flow, prospects and/or results of the Group.

Business risk factors

The Group's business, results of operations, value of assets, reserves, cash flows, financial condition and access to capital depend significantly upon, and may be adversely affected by, the level of oil and gas prices, which are highly volatile.

The Group's revenues, cash flow, reserve estimates, profitability and rate of growth depend substantially on prevailing international and local prices of oil and gas. Prices for oil and gas may fluctuate substantially based on factors beyond the Group's control. Consequently, it is impossible to accurately predict future oil and gas price movements. Oil and gas prices are volatile and have witnessed significant changes in recent years, for many reasons including, but not limited to, changes in global and regional supply and demand, geopolitical uncertainty, availability of equipment and new technologies, weather conditions and natural disasters, terrorism as well as global and regional economic conditions. Sustained lower oil and gas prices or price declines may inter alia lead to a material decrease in the Group's net production revenues.

Currently, all of the Group's production comes from fields in the PNGF Sud asset in Congo Brazzaville. The Aje Transaction, if completed, will add a producing asset in Nigeria. Under any circumstance, the Group's operations and cash flow will be restricted to a very limited number of fields. If mechanical or technical problems, storms, shutdowns or other events or problems affect the current or future production of the current producing assets of the Group, or new fields coming into production, it may have direct and significant impact on a substantial portion of the Group's production and hence the Group's revenue, profits and financial position as a whole.

Rising climate change concerns have led and could lead to additional legal and/or regulatory measures which could result in project delays or cancellations, a decrease in demand for fossil fuels and additional compliance obligations, each of which could materially and adversely impact the Group's costs and/or revenues.

Risk Factors
Continued

In general, the Group's operations are subject to risks which are typical for the offshore oil and gas industry, all of which may have a material adverse effect on the Group's operations, cash flow and financial position, including but not limited to risks relating to:

- extension of existing licenses and permits, including whether any extensions will be subject to onerous conditions;
- delays, cost inflation, potential penalties and regulatory requirements with respect to exploration, development projects and production of hydrocarbons, and hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors;
- decommissioning obligations and activities will incur costs and such costs may be in excess of expectations and budgets;
- third-party risk in terms of operators and partners and conflicts within a license group, such as the publicly know disputes within the Aje group;
- capacity constraints and cost inflation in the service sector and lack of availability of required services and equipment;
- restricted or limited access to necessary infrastructure or capacity booking for the transportation of oil and gas;
- restrictions with respect to offtake of oil and gas, including currency exchange regulations delaying or preventing timely settlement, offtaker credit risks as well as hostilities or acts of terrorism or war preventing offtake or impeding offtake and further production of crude.
- restrictions in the ability to sell or transfer license interests due to regulatory consent requirements, provisions in its joint operating agreements including pre-emption rights, if any, or applicable legislation;
- extremely complex and stringent regulations concerning health, safety and environment issues; and
- capsizing, environmental pollution to sea and air and other maritime disasters.

Financial risk factors

The overall risk management program seeks to minimize the potential adverse effects of unpredictable fluctuations in financial markets on financial performance, i.e., risks associated with currency exposures, and debt servicing. Financial instruments such as derivatives, forward contracts and currency swaps are continuously being evaluated for the hedging of such risk exposures.

Due to the international nature of its operations, the Group is exposed to risk arising from currency exposure, primarily with respect to the Norwegian Kroner (NOK), and the Great British Pound (GBP).

The Group's activities are and will continue to be capital intensive. The Group expects future investments into existing and new hydrocarbon assets to be served by cash-flow from ongoing operations. However, it is also expected that the Group will look to raise debt to part-fund future growth. Such debt may not be timely available, or only be available at terms which are unattractive or makes investments less profitable than first expected. Restrictions in raising, or the unavailability of, debt may prevent the Group from growing as planned and may make the Group to forego or lose attractive opportunities, which in turn could have a negative impact on the Group's financial position and future prospects.

Equal opportunities

PetroNor is an equal opportunity employer, with an equality concept integrated in its human resources policies. A diversified working environment is embraced, and the Group's personnel policies promote equal opportunities and rights and prevent discrimination based on gender, ethnicity, colour, language, religion or belief. All employees are governed by PetroNor's Code of Conduct, to ensure uniformity in behaviour across a workforce representing a multitude of nationalities.

PetroNor is a knowledge-based group in which a majority of the workforce has earned college or university level educations; or has obtained industry-recognized skills and qualifications specific to their job requirements. Employees are remunerated exclusively based upon skill level, performance and position.

Proportion of local West African employees

	Actual	Objective
Staff	58%	50%
Board	Nil	+20%

Proportion of women

	Actual	Objective
Staff	36%	+20%
Executive management team	Nil	+20%
Board	29%	+40%

Share Capital

As at 31 December 2020, the Company's share capital consists entirely of 971,665,288 ordinary shares, with 99.7% of the Company's ordinary shares admitted for trading on Oslo Euronext Expand (Norway).

Rights and obligations of shareholders

In accordance with section 5-8a of the Norwegian Securities Trading Act, the Company provides the following information:

a. there are no restrictions on the transfer of securities;
b. no holders of any securities have special control rights;
c. the Company does not operate an employee share scheme;
d. there are no restrictions on voting rights;
e. there are no agreements between shareholders which are known to the Company and which may result in restrictions on the transfer of securities and/or voting rights within the meaning of Directive 2001/34/EC;
f. the Company's Constitution provides that the Board of Directors shall have no fewer than 3 directors and no more than 12 directors. The directors are elected by a general meeting of shareholders by ordinary resolution. Additionally, pursuant to Clause 13.4 of the Constitution, the Board of Directors may at any time appoint a person to be a Director, provided that the maximum number of Directors is not exceeded. Any such Director appointed will hold office until the next general meeting and will be eligible for re-election. At the Company's annual general meeting, one-third of the Directors for the time being, shall retire from office, provided always that no Director except a Managing Director shall hold office for a period in excess of three years without submitting himself for re-election. The Directors to retire at an annual general meeting are those who have been longest in office since their last election. A retiring Director is eligible for re-election. In the event of equal voting at a director's meeting, the chairman of the meeting shall have a second or casting vote providing there is more than two directors competent to vote on the question. As the Company is incorporated in Australia, the Australian Corporations Act requires the Company to have at least two directors that reside in Australia.
g. the Company may modify or repeal its constitution or a provision of its constitution by special resolution of shareholders;
h. pursuant to section 198A of the Australian Corporations Act, the business of a company is managed by or under the direction of the Board of Directors. Pursuant to Clause 2.2 of the Company's Constitution, the Board of Directors has the power to issue shares;
i. subject to the requirements in the Australian Corporations Act, the Company may purchase its own shares in accordance with the buy-back provisions of the Australian Corporations Act, on such terms and at such times as may be determined by the Directors from time to time and approved by the shareholders as required pursuant to the Australian Corporations Act. The Company is not entitled to hold its own shares, subject to exceptions set out in Section 259A of the Australian Corporations Act. Any shares repurchased by the Company will need to be cancelled;
j. there are no significant agreements to which the Company is a party, and which take effect, alter or terminate upon a change of control of the Company following a takeover bid;
k. with the exception of senior management Chris Butler and Michael Barrett, there are no agreements between the Company and its board members or employees providing for compensation if they resign or are made redundant without valid reason or if their employment ceases because of a takeover bid.

As at 9 April 2021, after Tranche 1 of the post year end Private Placement the Company had 3,067 shareholders and 1,056,028,924 shares, with (99.7%) registered in the VPS. The table below shows the 20 largest shareholders in the Company:

#	Shareholder	Number of Shares	Per cent
1	Petromal LLC [1]	403,936,700	38.25%
2	NOR Energy AS [2]	143,555,857	13.59%
3	Gulshagen III AS [3]	45,000,000	4.26%
4	Gulshagen IV AS [3]	45,000,000	4.26%
5	Ambolt Invest AS	45,000,000	4.26%
6	Lenger Nedi Hagan AS	45,000,000	4.26%
7	ENG Group Soparfi S.A.	40,681,739	3.85%
8	Gulshagan II AS	37,607,768	3.56%
9	Enga Invest AS	19,692,746	1.86%
10	Pust For Livet AS	15,000,000	1.42%
11	Nordnet Bank AB	12,064,798	1.14%
12	Nordnet Livsforsikring AS	10,527,921	1.00%
13	Telinet Energi AS	9,768,377	0.93%
14	Omar Al-Qattan	7,645,454	0.72%
15	Leena Al-Qattan	7,645,454	0.72%
16	UBS Switzerland AG	6,570,123	0.62%
17	Sandberg JH AS	4,653,951	0.44%
18	Avanza Bank AB	4,399,286	0.42%
19	Danske Bank A/S	4,363,499	0.41%
20	Singh Baldev	4,051,424	0.38%
	Subtotal	**912,165,097**	**86.38%**
	Others	143,863,827	13.62%
	Total	**1,056,028,924**	**100.00%**

[1] Non-Executive Chairman, Mr. Alhomouz is the CEO of Petromal LLC.

[2] NOR Energy AS is a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through indirect beneficial interests.

[3] Gulshagan III AS and Gulshagan IV AS are companies controlled by Mr. Søvold through an indirect beneficial interest.

Directors & Company Secretary

The Company has seven Directors on the Board. The Directors have various backgrounds and experience, offering the Group and the Company valuable perspectives on industrial, operational and financial issues. The qualifications and experience of the current directors is detailed on pages 24 & 25.

The former directors of the Company that held office during the year ended 31 December 2020 were as follows:

Knut Søvold
Executive Director and Chief Executive Officer

Qualifications
MSc in Petroleum from The Institute of Technology in Trondheim (NTH), Norway

Experience
Mr. Søvold has 30 years of experience in the oil and gas industry, from both executive management and technical levels. His extensive experience covers fields and licenses in the North Sea, North and West Africa, Middle East, Far East and FSU, as well as management and administration through establishing and operating companies in Norway, UK, Kazakhstan and West Africa. Mr. Søvold was in the management team of the Snorre Field in the North Sea, with a production of 200,000 bopd. Mr. Søvold has been working with West African assets since 2000 and in Nigeria since 2008. Furthermore, he has also been working with gas to LNG, including novel solutions such as FLNG, gas to power, as well as LNG-regasification.

Mr. Søvold is a founding member of PetroNor, and although he has resigned from the Board, he remains fully commited to the Company as the Chief Executive Officer.

Gerhard Ludvigsen
Executive Director and Business Development Manager

Qualifications
BSc in Business Administration from Long Beach University, California, USA

Experience:
Mr. Ludvigsen is the founder of several companies in Norway, including PetroNor, and internationally within the oil and gas industry, as well as holding several board positions in start-up companies and being an advisor for a major securities house in Norway. Founded Hemla with AGR as co-founder with focus on oil and gas development, co-founded D&H Solutions AS with Daewoo Shipbuilding & Marine Engineering of South Korea for gas and LNG development with major international oil companies in Middle East and Africa. Mr. Ludvigsen has also been a director and major shareholder of FileFlow, developed by Fast Search & Transfer. Mr. Ludvigsen serves on the board of the charity foundation Power to Educate which supports education in emerging countries.

Stephen West
Executive Director and Chief Financial Officer

Qualifications
FCA (Australia & New Zealand)
ACA (England & Wales)
Bachelor of Commerce (Accounting and Business Law) - Curtin University of Technology

Experience
Mr. West has over 23 years of financial and corporate experience gained in public practice, oil and gas, mining and investment banking spanning Australia, United Kingdom, Europe, CIS and Africa. During his career Mr. West has held senior positions at Horwath Chartered Accountants, PricewaterhouseCoopers and Barclays Capital.

Dr. David King
Non-Executive Director

Qualifications
BSc (Hons) in Class 1 Physics/ Mathematics - University of East Anglia MSc and D.I.C. Geophysics - Imperial College London
PhD in Seismology - Australian National University

Experience
Dr. King is a professional geoscientist and has over 30 years' experience in oil and gas and other natural resources industries.

Timothy Turner
Non-Executive Director

Qualifications:
B.Bus, FCPA, CTA, Registered Company Auditor.

Experience
Mr. Turner has 25 years' experience in new ventures, capital raisings and general business consultancy, in addition to 15 years of experience in ASX listed junior resource-based exploration companies.

Directors & Company Secretary
Continued

Interests in Shares & Options
As at the date of this report:

Mr. Pace holds 1,498,938 shares.

Mr. Alhomouz has no personal interests in shares and options, but has influence over 403,936,700 shares as the CEO of significant shareholder Petromal LLC.

No other current board members hold shares or options.

Position as at resignation date:

NOR Energy AS, a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through an indirect beneficial interest, held 444,237,596 shares when Mr. Søvold resigned as a Director on 29 May 2020.

On 31 January 2021, NOR Energy AS held 233,555,857 shares when Mr. Ludvigsen resigned as a Director. Furthermore, Mr. Ludvigsen held 45,000,000 shares through an indirect beneficial interest in Nedi Hagan AS. In addition 15,000,000 shares were held by Pust For Livet AS, a company controlled by immediate family of Mr. Ludvigsen.

On resignation Mr. West held 1,377,544 shares through an indirect beneficial interest in Cresthaven Investments Pty Ltd. Dr. King and Mr. Turner held 30,000 and 4,167 shares respectively on resignation.

Meetings of directors
The number of directors' meetings (including committees) held during the period where each director held office during the financial year and the number of meetings attended by each director is:

	Audit Committee Meetings		Directors' Meetings	
Director	Eligible to attend	Attended	Eligible to attend	Attended
Current				
E Alhomouz	-	-	11	10
J Pace	2	2	11	11
J Iskander	2	1	11	9
A Neuling	2	2	9	9
R Steinepreis	-	-	9	8
I Tybring-Gjedde	-	-	7	5
G Kielland	-	-	-	-
Former				
K Søvold	-	-	4	4
G Ludvigsen	-	-	7	7
S West	-	-	1	1
D King	-	-	-	-
T Turner	-	-	-	-

In addition to meetings of directors held during the year, due to the number and diversified location of the directors, a number of matters are authorised by the board of directors via circulating resolutions. During the current year, 10 circulating resolutions were authorised by the board of directors. There were no Remuneration Committee or Continuous Disclosure Committee meetings during the year, as any relevant matters were discussed during the Directors' Meetings.

Indemnifying directors and officers
In accordance with the constitution, except as may be prohibited by the Corporations Act 2001, every director, principal executive officer or secretary of the Company shall be indemnified out of the property of the Company against any liability incurred by him/her in his/her capacity as director, principal executive officer or secretary of the Company or any related corporation in respect of any act or omission whatsoever and howsoever occurring or in defending any proceedings, whether civil or criminal.

Indemnification of auditors
To the extent permitted by law, the Company has agreed to indemnify its auditors, BDO Audit (WA) Pty Ltd ("BDO"), as part of the terms of its audit engagement agreement against claims by third parties arising from the audit (for an unspecified amount). No payment has been made to indemnify BDO during or since the financial year.

Health, Safety and Environment (HSE)

Health, Safety and Environment (HSE) policies are essential for PetroNor with the goal to avoid accidents and incidents and minimize the impact of its activities on the environment. PetroNor performs all its activities with focus on and respect for people and the environment. The Board believes this is a key condition for creating value in a very demanding business. The Group's objective for health, environment, safety and quality (HSEQ) is zero accidents and zero unwanted incidents in all activities. The Group strives towards performing all its activities with no harm to people or the environment. PetroNor experienced no accidents, injuries, incidents or any environmental claims during the year.

Time lost due to employee illness or accidents was negligible. Employee safety is of the highest priority, and the Group is continuously working towards identifying and employing administrative and technical solutions that ensure a safe and efficient workplace.

In light of the previously announced restructuring plans to install a Norwegian entity at the top of the Group and exit Australia, the Company is currently in the process of reassessing its set of operational guidelines and principles of Corporate Governance to adapt to a Norwegian legal jurisdiction.

The oil and gas assets located in West Africa imply frequent travel, and the Group seeks to ensure adequate safety levels for management and employees travelling.

With its non-operated licences, PetroNor is dependent on the efforts of the operators with respect to achieving physical results in the field. However, the Group has chosen to take an active role in all license committees with the conviction that high safety standards are the best means to achieve successful operations. Through this involvement, the Group can influence the choice of technical solutions, vendors and quality of applied procedures and practices. The Group's operations have been conducted by the operators on behalf of the licensees, at acceptable HSE standards and the Operator of PNGF Sud is reporting regularly on all key HSE indicators. No accidents that resulted in loss of human lives or serious damage to people or property have been reported.

To the best of the Group's knowledge, all operations have been conducted within the limits set by approved environmental regulatory authorities.

The Company is aware of its environmental obligations with regards to its exploration activities and ensures that it complies with the relevant environmental regulations when carrying out any exploration work. There have been no significant known breaches of the Company's exploration license conditions or any environmental regulations to which it is subject.

Corporate Social Responsibility/ Ethical Code of Conduct

The Company has a strong focus on CSR as well as an ethical code of conduct. The Company founders have established a separate CSR project, Power to Educate, and is supporting the CSR projects in the subsidiary in the Republic of Congo as well as the projects organized by the Operator in the PNGF Sud license group. During 2020, the Company registered as a supporting company with the Extractive Industries Transparency Initiative, EITI.

Payments to Governments

This country-by-country report has been developed to comply with the legal requirements in the Norwegian Security Trading Act ("Verdipapirhandelloven") § 5-5a, valid from 2014. The detailed regulation can be found in the regulation "Forskrift om land-for-land rapportering".

In 2020, the Company was engaged in extracting activities encompassed by the legislation above in the following countries: Republic of Congo, Nigeria, The Gambia, and Senegal. This report discloses relevant payments to governments for extractive activities in the countries above, in addition to some contextual information as required by the regulation in the "Forskrift om land-for-land rapportering".

Basis for preparation

The report includes direct payments to governments from subsidiaries, joint operations and joint ventures. In some cases, however, certain payments to governments may be made by an operator on behalf of a partnership. This is often the case for area fees. In such cases, the Company will report their paying interest share of the payment made by the operator.

Definitions

Government - In the context of this report, a government means any national, regional or local authority of a country. It includes a department, agency or undertaking controlled by that authority.

Project - For this reporting a project is defined as an investment in a concession agreement.

Licence fees - Typically levied on the right to use a geographical area for exploration, development and production and include rental fees, area fees, entry fees, severance tax and concession fees and other considerations for licences and/or concessions. Administrative government fees that are not specifically related to the extractive sector, or to access extractive resources, are excluded.

Materiality - As per the "Forskrift om land-for-land rapportering" payments made as a single payment, or as a series of connected payments that equal or exceed Norwegian Kroner (NOK) 800.000 during the year are disclosed.

Reporting currency - Payments to governments are converted from the functional currency of each legal entity into the presentation currency, United States Dollars (USD). The payments for entities whose functional currencies are other than USD are converted into USD at the foreign exchange rate at the average annual rate.

Payments to Governments and Contextual Information

The consolidated overview below discloses the sum of the Company's payments to governments in each individual country where extractive activities are performed, per country/project. See Figure 01 below.

As the Company is waiting for Government approval of the Aje transaction, no payments were made in relation to this project during 2020.

Due to the arbitration status of the ROP and SOSP licences in Senegal, no payments were made in relation to these projects during 2020.

Legal entities by country

As per the "Forskrift om land-for-land rapportering" it is required that the Company report on certain contextual information at corporate level. This includes information on localisation of subsidiary, employees per subsidiary and interests paid or payable to other legal entities within the Group.

Active legal corporate structure of the Group during 2020 is set out in Figure 02 below.

Figure 01

Project	Payments per project (USD'000) Royalties	Oil tax	Other amounts[1]	Total
PNGF Sud	9,830	17,078	1,504	28,385
Congo Total	15,387	29,894	1,504	28,385
A4	Nil	Nil	2,903	2,903
The Gambia Total	Nil	Nil	2,903	2,903

[1] Other amounts includes payroll and other local taxes

Figure 02

Country of Incorporation Name	Main country of operations	Employees[1]	Interest paid or payable to a group entity USD'000
Australia			
PetroNor E&P Ltd	United Kingdom	-	-
Cyprus			
PetroNor E&P Ltd	Cyprus	1	1,563
Norway			
PetroNor E&P AS	Norway	5	-
Hemla Africa Holding AS	Norway	-	-
Republic of Congo			
Hemla E&P Congo S.A.	Republic of Congo	3	545
United Kingdom			
PetroNor E&P Services Ltd	United Kingdom	3	-
Nigeria			
PetroNor E&P Ltd	Nigeria	4	-
Cayman Islands			
African Petroleum Gambia Ltd	The Gambia	2	-
African Petroleum Senegal Ltd	Senegal	-	-
Senegal			
African Petroleum Senegal SAU	Senegal	2	-

[1] Average number of employees' during the year

Significant changes in the state of affairs

There have been no significant changes in the Company's state of affairs during the current year.

Options

Unissued Shares under Option
At the date of this report unissued ordinary shares of the Company under option are:

Expiry Date	Exercise Price /NOK	Exercise Price /USD equivalent at 31 December 2020	Number Under Option
11 January 2022	2.50	0.28	213,400
31 May 2022	7.75	0.88	1,176,070
Total			1,389,470

During the current year, no ordinary shares were issued on the exercise of options (2019: nil).

Proceedings on behalf of Company

No person has applied for leave of Court to bring proceedings on behalf of the Company or intervene in any proceedings to which the Company is a party for the purpose of taking responsibility on behalf of the Company for all or any part of those proceedings.

The Company was not a party to any such proceedings during the year.

Significant events after the balance date

Due to a breach of covenants under the loan agreement between Hemla Africa Holding AS ("HAH") and MGI International SA, the commercial court, Tribunal de Commerce de Pointe Noire, in Congo has awarded HAH 9,900 shares in Hemla E&P Congo SA ("HEPCO"), increasing HAH's share of HEPCO with 9.9%, equivalent to PetroNor increasing its indirect interest in PNGF Sud with 1.40% at a cost of approximately USD 4 million. As per Congolese law, the award can be challenged in a higher court, and if so the timing of such further appeal and any final outcome are uncertain.

On 29 January 2021, Gerhard Ludvigsen resigned as an Executive Director and was replaced on 1 February 2021 by Gro Kielland appointed as an Non-Executive Director.

A CPR update prepared by AGR Petroleum Services AS on the Company's PNGF Sud asset in Congo was released on 11 March 2021. The update represented an increase of approximately 28% and 49% for 2P and 2C respectively on a gross basis.

On 12 March 2021, the Company raised NOK 340 million of new equity through a Private Placement of 309,090,909 new shares in the Company. The Private Placement received strong interest from new investors, including institutional investors and private family offices in Norway and internationally. Petromal Sole Proprietorship LLC and related group companies ("Petromal"), the Company's main shareholder owning 38.28% of all issued and outstanding shares in the Company, subscribed for Offer Shares at the Offer Price for an amount of NOK 130.2 million, which corresponding to their 38.28% pro-rata share of the Private Placement.

The Private Placement will generate NOK 187.4 million (USD 22.1 million) in cash and NOK 152.6 million (USD 18.0 million) as in-kind consideration for contingent acquisition of all of Symero Limited's ("Symero") shares in Hemla Africa Holding AS ("HAH") (the "Symero Transaction"). Symero is owned by NOR Energy AS, a company owned by Knut Søvold, CEO of the Company, and Gerhard Ludvigsen.

The net cash proceeds from the Private Placement will be used to finance drilling of infill wells and other increased oil recovery initiatives on PNGF Sud and general corporate purposes. The Private Placement is divided into two tranches: Tranche 1 ("Tranche 1") consisting of Offer Shares for NOK 92.8 million have been allocated to existing and new investors, including Petromal. The remaining Offer Shares have been subscribed by and allocated to Symero (for an amount equal to NOK 152.6 million (USD 18 million) ("Tranche 2a") and Petromal (for an amount equal to NOK 94.6 million) in order to retain its ~38.28% ownership ("Tranche 2b").

The Company released a Notice of Meeting ("Notice") for an extraordinary general meeting ("EGM") to be held on the 4 May 2021, as the Symero Transaction is a related party transaction and subject to approval by ordinary resolution. An independent expert report was attached to the Notice as required pursuant the Australian Corporations Act.

The Company is contemplating to carry out a subsequent offering of new shares without tradable subscription rights of up to 60,000,000 new shares in the Company (equivalent to NOK 66 million) towards existing shareholders of the Company as of close of trading on Oslo Euronext Expand on 11 March 2021, shareholders of record on 15 March 2021. A combined prospectus for listing of the Offer Shares in Tranche 2a and Tranche 2b and for the offering of shares in the contemplated Subsequent Offering is expected to be published during May 2021.

On 5 April 2021, the Company announced that the arbitration proceedings for the Group's interests in Senegal were to resume despite numerous progressive meetings with the relevant authorities to reach a mutually beneficial solution.

On 26 April 2021, the Company announced that the regulatory approval for acquisition of SPE Guinea Bissau AB had been received, satisfying the condition precedent for completion.

Except for the above, the Company has not identified any events with significant accounting impacts that have occurred between the end of the reporting period and the date of this report.

Likely developments and expected results

With the governmental approval for the Sinapa and Esperança licences now received, the Company looks forward to the completion of the share purchase agreement for SPE Guinea Bissau AB in the coming week.

The Company is awaiting the governmental approval for Aje transaction and anticipates this to complete in the next few months.

The Company was pleased to announce post period two transactions to increase its net indirect interest in core asset PNGF Sud from 10.5% to 16.83%, as this will generate ~60% increase in PetroNor's PNGF Sud production and reserves with no impact on overhead costs;

Net production from PNGF Sud to increase from 2,385 barrels of oil per day ("bopd") to 3,850 bopd, based on 2020 average production;

Net 2P reserves as of Year-end 2020 increasing from 12.62 million to 20.23 million barrels of oil ("MMbbl");

After completion of Tranche 2a and 2b of the Private Placement, PetroNor will be in a robust financial position and fully funded for all sanctioned activities with significant flexibility to adjust its capital expenditure in a low oil price environment.

The infill drilling program on the Litanzi and Tchendo fields has been further delayed mainly due to the pandemic and is expected to restart in the H2-2021.

The Board wishes to thank the staff, consultants, services providers and shareholders for their continued commitment to the Company.

Auditor's independence declaration

The auditor's independence declaration for the year ended 31 December 2020 has been received and can be found on page 43 of the annual report.

Non-audit services

Non-audit services were provided by the entity's auditor's BDO, as per Note 7b. The directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

This report is made in accordance with a resolution of the Board of Directors, 29 April 2021

Eyas Alhomouz
Chairman of the Board

Gro Kielland
Director of the Board

Joseph Iskander
Director of the Board

Roger Steinepreis
Director of the Board

Jens Pace
Director of the Board

Alexander Neuling
Director of the Board

Ingvil Smines Tybring-Gjedde
Director of the Board

Financial Statements

Declaration of Independence by Phillip Murdoch to the Directors of Petronor E&P Limited

BDO

As lead auditor of PetroNor E&P Limited for the year ended 31 December 2020, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the Corporations Act 2001 in relation to the audit; and
2. No contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of PetroNor E&P Limited and the entities it controlled during the period.

Phillip Murdoch
Director
BDO Audit (WA) Pty Ltd
Perth, 29 April 2021

Consolidated Statement Profit or Loss and Other Comprehensive Income

	Note	For the year ended 31 December 2020 USD'000	For the year ended 31 December 2019 USD'000
Revenue	4	**67,543**	102,760
Cost of sales	5	**(25,885)**	(37,207)
Gross profit		**41,658**	65,553
Other operating income	6	**45**	9
Administrative expenses	7	**(12,376)**	(19,793)
Profit from operations		**29,327**	45,769
Finance expense	8	**(2,606)**	(1,822)
Foreign exchange gain / (loss)		**1,507**	(440)
Share based payment	23	**-**	(19,374)
Profit before tax		**28,228**	24,133
Tax expense	9	**(17,078)**	(29,894)
Profit/(Loss) for the year		**11,150**	(5,761)
Other Comprehensive income			
Exchange losses arising on translation of foreign operations		**(1,050)**	-
Total comprehensive income/(loss)		**10,100**	(5,761)
Profit/(Loss) for the year attributable to:			
Owners of the parent		**2,373**	(13,364)
Non-controlling interest		**8,777**	7,603
		11,150	(5,761)
Total comprehensive income/(loss) attributable to:			
Owners of the parent		**1,417**	(13,364)
Non-controlling interest		**8,683**	7,603
		10,100	(5,761)

Earnings per share attributable to members:		USD cents	USD cents
Basic profit/(loss) per share	10	**0.24**	(1.54)
Diluted profit/(loss) per share	10	**0.24**	(1.54)

The accompanying notes form part of these financial statements.

Consolidated Statement of Financial Position

	Note	As at 31 December 2020 USD'000	As at 31 December 2019 USD'000
Assets			
Current assets			
Inventories	11	**3,578**	3,233
Trade and other receivables	12	**9,397**	24,772
Cash and cash equivalents	13	**14,113**	27,891
		27,088	55,896
Non-current assets			
Property, plant and equipment	15	**23,483**	22,587
Intangible assets	16	**6,935**	4,691
Right-of-use assets	17	**212**	-
Other receivables	12	**21,260**	-
		51,890	27,278
Total assets		**78,978**	83,174
Liabilities			
Current liabilities			
Trade and other payables	18	**22,238**	34,602
Lease liability	17	**170**	-
Loans and borrowings	19	**4,000**	12,941
		26,408	47,543
Non-current liabilities			
Loans and borrowings	19	**14,912**	-
Lease liability	17	**55**	-
Provisions	20	**15,307**	14,373
		30,274	14,373
Total liabilities		**56,682**	61,916
NET ASSETS		**22,296**	21,258
Issued capital and reserves attributable to owners of the parent			
Share capital	21	**17,735**	17,735
Reserves	22	**(956)**	-
Retained earnings	22	**(8,853)**	(11,226)
		7,926	6,509
Non-controlling interests	24a	**14,370**	14,749
TOTAL EQUITY		**22,296**	21,258

The accompanying notes form part of these financial statements.
The financial statements were approved and authorised for issue by the Board of Directors on 29 April 2021.

Consolidated Statement of Changes in Equity

	Note	Issued capital USD'000	Share-based payment reserve USD'000	Foreign currency translation reserve USD'000	Retained earnings USD'000	Non-controlling interest USD'000	Total
For the year ended 31 December 2020							
BALANCE AT 1 JANUARY 2020		**17,735**	**-**	**-**	**(11,226)**	**14,749**	**21,258**
Profit for the year		**-**	**-**	**-**	**2,373**	**8,777**	**11,150**
Other comprehensive income:		**-**	**-**	**(956)**	**-**	**(94)**	**(1,050)**
Total comprehensive income for the year		**-**	**-**	**(956)**	**2,373**	**8,683**	**10,100**
Transactions with owners in their capacity as owners:							
Dividends paid during the year	22, 24a	**-**	**-**	**-**	**-**	**(9,062)**	**(9,062)**
BALANCE AT 31 DECEMBER 2020		**17,735**	**-**	**(956)**	**(8,853)**	**14,370**	**22,296**
For the year ended 31 December 2019							
BALANCE AT 1 JANUARY 2019		120	-	-	13,688	12,811	26,619
Profit/(loss) for the year		-	-	-	(13,364)	7,603	(5,761)
Other comprehensive income		-	-	-	-	-	-
Total comprehensive loss for the year		-	-	-	(13,364)	7,603	(5,761)
Transactions with owners in their capacity as owners:							
Issue of capital	21	17,615	-	-	-	-	17,615
Dividends paid during the year	22, 24a	-	-	-	(11,550)	(5,665)	(17,215)
BALANCE AT 31 DECEMBER 2019		17,735	-	-	(11,226)	14,749	21,258

The accompanying notes form part of these financial statements.

Consolidated Statement of Cash Flows

	Note	For the year ended 31 December 2020 USD'000	For the year ended 31 December 2019 USD'000
Cash flows from operating activities			
Profit for the year		**28,228**	24,133
Adjustments for:			
Depreciation and amortisation		**4,475**	3,323
Amortization of right-of-use asset		**169**	-
Unwinding of discount on decommissioning liability		**934**	877
Impairment of goodwill		**-**	9
Share-based payment expense		**-**	16,433
Net foreign exchange differences		**(1,050)**	-
		32,756	44,775
Decrease in trade and other receivables		**729**	6,724
Increase in advance against decommissioning cost		**(6,614)**	(3,286)
Increase in inventories		**(345)**	(663)
(Decrease)/increase in trade and other payables		**(12,363)**	24,950
Cash (used in)/generated from operations		**(18,593)**	27,725
Income taxes paid		**(17,078)**	(29,894)
Net cash flows from operating activities		**(2,915)**	42,606
Investing activities			
Purchases of property, plant and equipment		**(4,615)**	(12,466)
Purchases of intangible assets		**(3,007)**	-
Net cash flows from investing activities		**(7,622)**	(12,466)
Financing activities			
Issue of ordinary shares		**-**	1,182
Proceeds from loans and borrowings		**18,912**	12,917
Repayment of loans and borrowings		**(12,941)**	(7,059)
Repayment of principal portion of lease liability		**(131)**	-
Repayment of interest portion of lease liability		**(19)**	-
Dividends paid to non-controlling interest		**(9,062)**	(5,665)
Dividends paid		**-**	(11,550)
Net cash (used in)/from financing activities		**(3,241)**	(10,175)
Net increase/(decrease) in cash and cash equivalents		**(13,778)**	19,965
Cash and cash equivalents at beginning of year		**27,891**	7,926
Cash and cash equivalents at end of year	13	**14,113**	27,891

The accompanying notes form part of these financial statements.

Notes to the Consolidated Financial Statements

1. Corporate information

The financial report of the Company and its subsidiaries (together the "Group") for the year ended 31 December 2020 was authorised for issue in accordance with a resolution of the Directors on 29 April 2021.

PetroNor E&P Limited is a 'for profit entity' and is a Company limited by shares incorporated in Australia. Its shares are publicly traded on the Oslo Euronext Expand (code: PNOR), a regulated marketplace of the Oslo Stock Exchange, Norway. The principal activities of the Group are the exploration and production of crude oil.

2. Basis of preparation

The financial report is a general-purpose financial report, which has been prepared in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report has been prepared on a historical cost basis.

The financial report is presented in United States Dollars, which is also the functional currency for the Company and all material subsidiaries, and all values are rounded to the thousand dollars unless otherwise stated.

The financial report is presented as a continuance of the activities of the Cypriot company PetroNor E&P Limited, using the reverse acquisition rules for the merger that took place on 30 August 2019, Notes 3 & 23a.

Compliance statement

The financial report complies with Australian Accounting Standards. The financial report also complies with International Financial Reporting Standards "IFRS" as issued by the International Accounting Standards Board.

3. Significant accounting judgements, estimates and assumptions

The Directors evaluate estimates and judgements incorporated in the Financial Report based on historical knowledge and best-available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data, obtained both externally and within the Group.

Management has identified the following critical accounting policies for which significant judgements, estimates and assumptions are made. Actual results may differ from these estimates under different assumptions and conditions and may materially affect financial results or the financial position reported in future period.

Further details of the nature of these assumptions and conditions may be found in the relevant notes to the financial statements.

Hydrocarbon reserve and resource estimates

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The Group estimates its commercial reserves and resources based on information compiled by appropriately-qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production-Sharing Agreements. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The current long-term Brent oil price assumption used in the estimation of commercial reserves is 55 USD/bbl. The carrying amount of oil and gas properties and licenses at 31 December 2020 are shown in Note 15 and 16.

The Group estimates and reports hydrocarbon reserves in line with the principles contained in the Society of Petroleum Engineers (SPE) Petroleum Resources Management Reporting System (PRMS) framework. As the economic assumptions used may change and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of oil and gas properties may be affected due to changes in estimated future cash flows, Note 15;
- Depreciation and amortisation charges in the statement of profit or loss and other comprehensive income may change where such charges are determined using the UOP method, or where the useful life of the related assets change, Note 15);
- Provisions for decommissioning may require revision — where changes to reserves estimates affect expectations about when such activities will occur and the associated cost of these activities, Note 20.

Notes to the Consolidated Financial Statements
Continued

Taxes
The Group operates in several tax jurisdictions, and consequently, its income is subject to various rates and rules of taxation. As a result, the Company's effective tax rate may vary significantly depending upon the profitability of operations in the different jurisdictions.

The Group recognises the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction, to the extent that future cash flows and taxable income differ significantly from estimates. The ability of the Group to realise the net deferred tax assets recorded at the date of the statement of financial position could be impacted.

Additionally, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

Additional information on the accounting policy for taxes is explained further in Note 9 and 30m.

Decommissioning costs
Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The Group assesses its retirement obligation at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing, extent and amount of expenditure can also change, for example in response to changes in reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning costs. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The provision at reporting date represents management's best estimate of the present value of the future decommissioning costs required. Additional information is provided in Note 20.

Share-based payment – Costs of listing
The listed entity, PetroNor E&P Limited has not met the definition of a business for the reverse acquisition transaction, consequently no goodwill is allowed to be capitalised for the variance between the consideration paid and the fair value net assets on acquisition. Correspondingly, any excess-deemed acquisition costs must be accounted for as an expense in accordance with AASB 2, Note 23a.

For most reverse takeover transactions of listed shell companies, there is minimal variance between the consideration paid and the fair value of the net assets acquired, and any associated share-based expense may not be significant.

Due to the ongoing arbitration matters in Senegal and The Gambia and the uncertainty over legal tenure, these exploration licences had no book value in the accounting records of the Company on acquisition of African Petroleum Corporation Limited on 30 August 2019. This accounting treatment has meant there is a significant variance between the market value of the company as indicated by its publicly traded share price and the book net assets on completion of the transaction.

4. Revenue

	2020 USD'000	2019 USD'000
Revenue from contracts from customers		
Revenue from sales of petroleum products[1]	**40,635**	57,479
Other Revenue		
Assignment of tax oil	**17,078**	29,894
Assignment of royalties	**9,830**	15,387
Total Revenue	**67,543**	102,760
Quantity of oil lifted (barrels)	**993,574**	880,844
Average selling price (USD/barrel)	**40.90**	65.25
Quantity of net oil produced after royalty, cost oil and tax oil (barrels)	**999,522**	860,769

[1] All revenue from the sales of petroleum products is generated from a single customer and recognised and transferred at a point in time.

Notes to the Consolidated Financial Statements
Continued

5. Cost of sales

	2020 USD'000	2019 USD'000
Operating expenses	**11,357**	18,292
Royalty	**9,830**	15,387
Depreciation and amortisation of oil and gas properties	**4,429**	3,231
Closing oil inventory	**269**	297
	25,885	37,207

6. Other operating income

	2020 USD'000	2019 USD'000
Other	**45**	9

7. Administrative expenses

	Note	2020 USD'000	2019 USD'000
Employee benefit expenses	7a	**5,108**	4,035
Termination benefits		**795**	-
Travelling expenses		**282**	1,047
Legal and professional expenses		**3,121**	6,502
Office rent		**87**	214
Related-party loan write-off	24d	**-**	5,305
Depreciation and amortization		**46**	-
Amortization on right-of-use assets		**169**	-
Other expenses		**2,768**	2,690
		12,376	19,793

7a. Employee benefit expenses

	2020 USD'000	2019 USD'000
Salaries	**4,486**	3,331
Short-term non-monetary benefits	**319**	308
Defined contribution pension cost	**104**	75
Share-based payment expense	**-**	-
Social-security contributions and similar taxes	**199**	321
	5,108	4,035

Notes to the Consolidated Financial Statements
Continued

7b. Auditors' remuneration

	2020 USD'000	2019 USD'000
Paid or payable to BDO		
Audit review of financial reports		
BDO Audit (WA) Pty Ltd	**90**	55
BDO Network firms	**76**	118
	166	173
Other non-assurance services		
BDO related practices	**40**	12
	206	185
Paid or payable to other audit firms		
Audit or review of financial reports	**40**	138
Other non-assurance services	**120**	141
	160	279

Fees, excluding VAT, to the auditors are included in administration expenses.

8. Finance expense

	Note	2020 USD'000	2019 USD'000
Unwinding of discount on decommissioning liability	20	**934**	877
Loan structuring fee		**150**	106
Finance cost on lease liabilities	17	**19**	-
Interest on loan	19	**1,493**	822
Other interest		**10**	17
		2,606	1,822

9. Tax expense

	2020 USD'000	2019 USD'000
Petroleum revenue tax expense		
Current income tax charge	**17,078**	29,894
Total tax expense reported in the consolidated statement of comprehensive income	**17,078**	29,894

The income tax expense is only related to the subsidiary in Congo and represents the assignment of tax oil on the revenue from sales of petroleum products, Note 4. There was no income tax expense in the other subsidiaries' jurisdictions nor in the parent's jurisdiction as these companies are in taxable loss position in both 2020 and 2019. Average effective tax rate for the year was 25% (2019: 29%) based on gross revenue of the Group.

Deferred tax assets have not been brought to account in respect of tax losses and unrecognised capital allowances because as at 31 December 2020 it is uncertain when future taxable amounts will be available to utilise those temporary differences and losses. As at 31 December 2020, the carried forward gross tax loss is USD 110 million (2019: USD 202 million).

Notes to the Consolidated Financial Statements
Continued

10. Earnings per share

	2020 USD'000	2019 USD'000
Profit / (loss) attributable to ordinary shareholders		
Profit / (loss) from continuing operations attributable to the ordinary equity holders used in calculating basic / diluted profit per share	**2,373**	(13,364)
Profit / (loss) attributable to the ordinary equity holders used in calculating basic / diluted profit per share	**2,373**	(13,364)
	Number of shares	
Weighted average number of ordinary shares outstanding during the period used in the calculation of profit / (loss) per share		
Basic	**971,665,288**	868,020,990
Diluted	**974,229,968**	868,020,990

Options on issue are considered to be potential ordinary shares and have been included in the determination of diluted loss per share only to the extent to which they are dilutive. There are 1,389,470 options as at 31 December 2020 (2019: 3,266,470). These options have not been included in the determination of basic loss per share because they are considered to be anti-dilutive.

11. Inventories

	2020 USD'000	2019 USD'000
Crude oil inventory	**689**	871
Materials and supplies	**2,889**	2,362
	3,578	3,233

Crude oil inventory is valued at cost of 17.79 USD/bbl (2019: 23.13 USD/bbl).

The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realisable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses. The cost of inventory includes all costs related to bringing the inventory to its current condition, including processing costs, labour costs, supplies, direct and allocated indirect operating overhead and depreciation expense, where applicable, including allocation of fixed and variable costs to inventory.

12. Trade and other receivables

	Note	2020 USD'000	2019 USD'000
Recoverability less than one year			
Trade receivables		**5,408**	4,013
Due from related parties	24d	**3,639**	5,639
Advance against decommissioning cost [1]		**-**	14,646
Other receivables		**350**	474
		9,397	24,772
Recoverability more than one year			
Advance against decommissioning cost [1]		**21,260**	-
		21,260	-

[1] In addition to the booking of decommissioning cost asset and liability, the contractors group and the Congolese Government have decided to set up funds for the decommissioning cost in an escrow account which is managed by the operator. The advances of the funds for the year are made on the basis of an average rate of 3.70 USD/bbl produced (2019: 3.50 USD/bbl). As at the year end, the Group reassessed the classification of the USD 21.3 million cash advanced to the Operator in Congo towards the decommissioning cost as a Non-Current Asset in a change to the presentation on the Q4 2020 interim report. Although the JV partnership in 2019 agreed to refund previous surplus cash set aside for the decommissioning cost back into the operating cash pool, the current cash projection does not anticipate the same situation in the next 12 months. Refer to Note 20 for further details on the decommissioning liability.

Notes to the Consolidated Financial Statements
Continued

The Group measures the provision for impairment for trade receivables and amounts due from related parties at an amount equal to lifetime ECL. The ECL on trade receivables and amounts due from related parties are estimated using a provision matrix by reference to past default experience of the debtor and an analysis of the debtors' current financial position, adjusted for factors that are specific to the debtors' general economic conditions and forward looking elements of the industry in which the debtors operate and an assessment of both the current as well as the forecast direction of conditions at the reporting date. The trade receivables of USD 5.4 million is due from one customer only which is not past due yet. The Group considered significant increase in credit risk on its trade receivables and amounts due from related parties and estimates that no ECL is required as on 31 December 2020.

13. Cash and cash equivalents

	2020 USD'000	2019 USD'000
Cash in bank	**14,113**	26,988
Petty cash	**-**	-
Restricted cash	**-**	903
	14,113	27,891

Restricted cash balances represent cash-backed security provided in relation to the Company's obligations required under the exploration licences. The cash will be utilised for training and resources by mutual agreement with the relevant country's government authorities.

14. Segment information
For management purposes, the Group is organised into one main operating segment, which involves exploration and production of hydrocarbons. All of the Group's activities are interrelated, and discrete financial information is reported to Chief Operating Decision Maker as a single segment. Accordingly, all significant operating decisions are based upon analysis of the Group as one segment. The financial results from this segment are equivalent to the financial statements of the Group as a whole.

The Group only has one operating segment, being exploration and production of hydrocarbons.

The analysis of the location of non-current assets is as follows:

	2020 USD'000	2019 USD'000
Congo	**48,677**	27,182
Gambia	**3,007**	-
Nigeria	**1**	-
Norway	**205**	83
Senegal	**-**	2
UK	**-**	11
	51,890	27,278

Notes to the Consolidated Financial Statements
Continued

15. Property, plant, and equipment

	2020 USD'000	2019 USD'000
Production assets and equipment		
Cost		
At 1 January	**28,830**	16,464
Additions	**4,615**	12,375
Disposals	**-**	(9)
At 31 December	**33,445**	28,830
Depreciation		
At 1 January	**6,243**	3,884
Charge for the year	**3,719**	2,368
Depreciation on disposals	**-**	(9)
At 31 December	**9,962**	6,243
Net carrying amount		
At 31 December	**23,483**	22,587

Production assets and equipment cost includes the following:

	Note	2020 USD'000	2019 USD'000
Decommissioning costs	20	**11,899**	11,899
Oil & gas CAPEX		**21,546**	16,932
		33,445	28,830

16. Intangible assets
Licences and approval

	2020 USD'000	2019 USD'000
Cost		
At 1 January	**7,389**	7,389
Addition	**3,007**	-
At 31 December	**10,396**	7,389
Accumulated amortisation and impairment		
At 1 January	**2,698**	1,833
Amortisation	**763**	865
Impairment	**-**	-
At 31 December	**3,461**	2,698
Net carrying value		
At 1 January	**4,691**	5,556
At 31 December	**6,935**	4,691

Notes to the Consolidated Financial Statements
Continued

Licence overview
Congo
In 2017, subsidiary company Hemla E&P Congo SA acquired interest in three development and production permits (Tchendo: 20%; Tchibouela: 20% and Tchibeli-Litanzi: 20%) which will respectively end in December 2037 for each of them with possible extension for 5 years. All these three licenses are called or named collectively "PNGF Sud" and have an area of 482.28km². The operator of the licences is Perenco, and the carrying value as at 31 December 2020 is USD 3.9 million.

There were no indicators of impairment identified under IAS 36 and IAS 38 as at 31 December 2020 for the licence cost and property plant and equipment.

The Gambia
During the year the Company was awarded a new 30-year licence for the A4 licence, as part of the settlement agreement for the previous A1 and A4 licences. The A4 licence area is 1,376km² and is operated by Company subsidiary PetroNor E&P Gambia Ltd. As at 31 December 2020 the carrying value of the A4 licence is USD 3.0 million.

There were no indicators of impairment identified under IAS 38 as at 31 December 2020 for the licence cost.

Senegal
As at the date of this report, the Company's subsidiary African Petroleum Senegal Limited had registered a request for arbitration proceedings with the International Centre for the Settlement of Investment Disputes (ICSID) to protect its interests in the Senegal Offshore Sud Profond and Rufisque Offshore Profond blocks in Senegal (ICSID case ARB/18/24). The combined licences cover an area of 15,796km2 and due to the arbitration process have nil carrying value in the financial statements as at 31 December 2020.

Reserves
The Group has adopted a policy of regional reserve reporting using external third-party companies to audit its work and certify reserves and resources. Reserve and contingent resource estimates comply with the definitions set by the Petroleum Resources Management System ("PRMS") issued by the Society of Petroleum Engineers ("SPE"), the American Association of Petroleum Geologists ("AAPG"), the World Petroleum Council ("WPC") and the Society of Petroleum Evaluation Engineers ("SPEE") in March 2007. The Group uses the services of AGR Petroleum Services AS for 3rd party verifications of its reserves.

The following is a summary of key results from the reserve reports (net of the Group's share):

Asset	1P reserves MMbbls	2P reserves MMbbls	3P reserves MMbbls
PNGF Sud	9.05	12.62	16.00

Definitions:
1P) Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

2P) Proved plus Probable Reserves

Probable Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

3P) Proved plus Probable plus Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Probable Reserves.

Notes to the Consolidated Financial Statements
Continued

17. Leases

	Right-of-use assets: Office building USD'000	Lease liabilities USD'000
At 1 January 2020	**-**	**-**
Additions	**381**	**337**
Amortization expense	**(169)**	**-**
Interest expense	**-**	**19**
Payments made	**-**	**(131)**
At 31 December 2020	**212**	**225**
Ageing of lease liabilities		
Current		**56**
Non-current		**170**

Amounts recognised in profit and loss

	31 December 2020 USD'000
Amortization expense on right-of-use assets	**169**
Interest expense on lease liabilities	**19**
Expense relating to short-term lease	**136**
	324

The total cash outflow for leases amount to USD 150,000 for the year.

18. Trade and other payables

	Note	2020 USD'000	2019 USD'000
Trade payables		**5,226**	14,809
Due to related parties	24d	**11,694**	13,784
Taxes and state payables		**348**	473
Other payables and accrued liabilities		**4,970**	5,536
		22,238	34,602

Notes to the Consolidated Financial Statements
Continued

19. Loans and borrowings

	2020 USD'000	2019 USD'000
At 1 January	**12,941**	7,083
Received	**18,912**	12,917
Principal repayment	**(12,941)**	(7,059)
Interest on loan accrued	**1,493**	822
Interest on loan paid	**(1,493)**	(822)
At 31 December	**18,912**	12,941

	2020 USD'000	2019 USD'000
Ageing of loans payable		
Current	**4,000**	12,941
Non-current	**14,912**	-
	18,912	12,941

During the year, the short-term debt facility of USD 12.9 Million from Rasmala (London and Dubai based investor group) was replaced with a USD 15 Million facility with 12 months grace period and final maturity date in October 2022. The loan is repaid in monthly instalments after the initial grace period and carries an interest rate of 9% plus one-month LIBOR payable monthly if the oil price is below 40 USD/bbl and 12% if the oil price is above 40 USD/bbl. The loan is secured against:

- The assignment of receivables by subsidiary company Hemla E&P Congo SA;
- Pledge over one of the bank accounts of subsidiary company Hemla Africa Holding AS;
- Pledge over one of the bank accounts of subsidiary company Hemla E&P Congo SA;
- Pledge over shares in subsidiary companies, Hemla Africa Holding AS and Hemla E&P Congo SA;
- Assignment of inter-company loan agreement between Hemla Africa Holding AS and Hemla E&P Congo SA; and
- Corporate guarantees by the parent company and its subsidiaries PetroNor E&P Ltd. Cyprus and Hemla E&P Congo SA.

On 28 September 2020, subsidiary company Hemla Africa Holding AS paid a USD 3.9 Million dividend to minority interest and related party Symero Ltd. An amount equal to the dividend was immediately loaned to the Parent Company by Symero Ltd with interest rates matching those already provided by external financing and no security was provided for the loan. The maturity date is matched to the USD 15 Million facility from Rasmala. All covenants were complied with and there were no breaches during the year for both loans payable to Rasmala and Symero.

20. Provisions

Decommissioning liability

In accordance with the agreements and legislation, the wellheads, production assets, pipelines and other installations may have to be dismantled and removed from oil and natural gas fields when the production ceases. The exact timing of the obligations is uncertain and depends on the rate the reserves of the field are depleted. However, based on the existing production profile of the PNGF Sud field and the size of the reserves, it is expected that expenditure on retirement is likely to be after more than ten years. The current bases for the provision are a discount rate of 6.0% (2019: 6.5%) and an inflation rate of 1.6% (2019: 1.6%). The initial decommissioning liability (ARO) study was prepared internally by the operator Perenco and was presented to ARO Committee in 2018. The Company reassessed the applicable discount rate during 2020 based on the rates of government bonds issued in the Congo during the year. The Group reassessed the applicable discount rate during 2020 based on the rates of Congolese Government bonds issued in the Congo during the year. The impact of the change in discount factor was not considered material.

The following table presents a reconciliation of the beginning and ending aggregate amounts of the obligations associated with the retirement of oil and natural gas properties:

	Note	2020 USD'000	2019 USD'000
At 1 January		**14,373**	13,496
Arising during the year		**-**	-
Unwinding of discount on decommissioning	8	**934**	877
At 31 December		**15,307**	14,373

Notes to the Consolidated Financial Statements
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21. Share capital
Ordinary shares participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held and in proportion to the amount paid up on the shares held.

At shareholders' meetings, each ordinary share entitles the holder to one vote in proportion to the paid-up amount of the share when a poll is called, otherwise each shareholder has one vote on a show of hands.

Reconciliation of movement in shares on issue

	Number of fully paid ordinary shares	
	2020	2019
Balance at the beginning of the year	**971,665,288**	-
Balance of shares of Cypriot PetroNor E&P Ltd prior to merger	**-**	100,000
Balance of shares of Australian PetroNor E&P Limited prior to merger	**-**	155,466,446
Acquisition of Cypriot PetroNor E&P Ltd shares	**-**	(100,000)
Issue of shares for merger consideration [1]	**-**	816,198,842
Balance at end of the year	**971,665,288**	971,665,288

[1] On 30 August 2019, the Company issued 816,199,842 shares at NOK 1.032 each

Reconciliation of movements in issued capital

	2020 USD'000	2019 USD'000
Balance at beginning of the year Fair value of issued share capital at beginning of the year	**17,735**	120
Issue of shares for reverse takeover1	**-**	17,615
Share capital at end of the year	**17,735**	17,735

[1] On 30 August 2019, the Company issued 816,199,842 shares at NOK 1.032 each

Capital Management
Management controls the capital of the Company in order to maximise the return to shareholders and ensure that the Company can fund its operations and continue as a going concern. Capital is defined as issued share capital.

Management effectively manages the Company's capital by assessing the Company's financial risks and adjusting its capital structure in response to changes in these risks and in the market. These responses include the management of expenditure and debt levels, distributions to shareholders and share and option issues. There have been no changes in the strategy adopted by management to control the capital of the Company since the prior reporting period.

Management monitors capital requirements through cash flow forecasting. Management may seek further capital if required through the issue of capital or changes in the capital structure. The Group has no externally imposed capital requirements.

Notes to the Consolidated Financial Statements
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22. Reserves
The movement in reserves are reflected in the statement of changes in equity.

Share-based payment reserve
The share-based payments reserve records options and share awards recognised as expenses, issued to employees, directors, and consultants. See note 23 for further details on share-based payments.

Foreign currency translation reserve
The foreign currency translation reserve is used to recognise foreign currency exchange differences arising on translation of functional currency to presentation currency.

Retained earnings
All other net gains and losses and transactions with owners not recognised elsewhere.

Dividends
No dividends were declared during the year by the Parent Company. During 2019, the cash consideration of USD 11,549,988 for the reverse acquisition transaction was deemed and classified as dividend, Note 23.

23. Share based payments

	2020 USD'000	2019 USD'000
Reverse acquisition – Costs of listing	-	19,374
Warrants	-	-
Options	-	-
Share based payment charge for the year	-	19,374

23a. Reverse acquisition – costs of listing
On 30 August 2019, the Company entered into a share purchase agreement with the Cypriot company PetroNor E&P Limited. Consideration for 100% of the share capital of the Cypriot company comprised the following:
- 816,198,842 new shares issued at NOK 1.032 each;
- 155,466,446 warrants issued with a nil exercise price, vesting conditions and expiry date of 31 December 2019. The vesting conditions related to specific performance milestones including the signing of a binding gas offtake agreement for an asset in Nigeria; and
- USD 11,549,988 deferred cash consideration, payable and due upon the finalisation of the 2018 dividend from the operating subsidiary company Hemla E&P Congo SA.

Costs associated with the transaction totalled USD 2 million; and has been expensed as incurred by both sides. Therefore, only costs of USD 1.19 million are included in the Statement of Comprehensive Income for the transaction, with the balance recognised as part of the retained losses of Australian PetroNor E&P Limited at the point of the merger.

The transaction has been considered a reverse takeover, but not a business combination. Although the Australian company PetroNor E&P Limited has licences in The Gambia and Senegal, with the ongoing arbitration matters there were no active operations, consequently the Company was considered a 'non-business' listed company.

The Cypriot company PetroNor E&P Limited is considered the accounting acquirer and the Australian company PetroNor E&P Limited is the legal acquirer.

The acquisition is accounted for as a continuation of the financial statements of the Cypriot PetroNor E&P Limited. The Transaction assessed fair value in excess of the net assets of Australian PetroNor E&P Limited, and an estimate for listing expenses has been expensed as a share-based payment in accordance with AASB 2.

Notes to the Consolidated Financial Statements

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The estimate for listing expenses is based on the deemed market capitalisation of the company:

		Number of shares [1]	Share value USD'000
Existing Australia PetroNor E&P Limited shareholders	**16%**	**155,466,446**	**17,615**
New issue to Cypriot PetroNor E&P Ltd shareholders[1]	**84%**	**816,198,842**	**92,479**
Deemed market capitalisation of the Company	**100%**	**971,665,288**	**98,544**

[1] Share price on completion date 30 August 2019, NOK 1.032 (equivalent USD 0.113)

	2019 USD' 000
Implied Issued capital for acquisition of Australian PetroNor E&P Limited	17,615
Add net book value of Australian PetroNor E&P Limited net liabilities acquired as at 30 August 2019	1,759
Share based payment charge for the year	**19,374**

Accounting treatment of exploration assets only allows intangible asset values to be carried forward and not impaired, if the Company can demonstrate legal right of tenure. Due to the ongoing arbitration matters for the Senegalese and Gambian licences, there was uncertainty around the legal right of tenure for these licences. For this reason, the book carrying value of these assets is nil for the transaction. However, prior to completion of the reverse acquisition transaction the market capitalisation of Australian company PetroNor E&P Limited exceeded the book value of its net liabilities, therefore implying the Senegalese and Gambian licences had significant residual value and supports the material share-based payment charge recognised for the transaction.

23b. Warrants

There were no warrants issued during the year.

During the previous year, 8,513,848 unlisted warrants were issued to staff, Directors and consultants of the Company; these were subject to vesting conditions dependent on operational performance milestones related to the reinstatement of licences in The Gambia and Senegal.

During the previous year, 310,932,892 unlisted warrants were issued to shareholders of the Company, these were subject to vesting conditions dependent on operational performance milestones either related to the reinstatement of licences in The Gambia and Senegal, or the signing of a binding gas offtake agreement for an asset in Nigeria.

None of these warrants vested before the expiry date of 31 December 2019, and consequently as at the year-end, there were no unlisted warrants outstanding. No expense was recognised within the Statement of Comprehensive Income for the issue of these warrants, as the warrants were subject to vesting conditions that did not occur; and were awarded and lapsed during the same period.

Notes to the Consolidated Financial Statements
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23c. Options
Holders of options do not have any voting or dividend rights in relation to the options.

The Company has used the Black-Scholes methodology for measuring the option pricing.

The following reconciles the outstanding share options granted, exercised and forfeited during the year:

	2020		2019	
	Number of options¹	Weighted average exercise price equivalent USD¹	Number of options¹	Weighted average exercise price equivalent USD¹
Balance at beginning of the period	**3,266,470**	**0.53**	-	-
Awarded	**-**	**-**	-	-
Reverse takeover²	**-**	**-**	3,283,137	0.53
Lapsed	**(1,877,000)**	**0.34**	(16,667)	2.10
Forfeited during the year	**-**	**-**	-	-
Balance at end of the year	**1,389,470**	**0.81**	3,266,470	0.53
Exercisable at end of the year	**1,389,470**	**0.81**	3,266,470	0.53

¹ The USD equivalent weighted average exercise price as at 31 December 2020
² On August 2019, 3,283,137 options were recognised in relation to outstanding options awarded before the reverse acquisition transaction with PetroNor E&P Limited took place.

The value of options capitalised during the year was nil (2019: nil).

The share options outstanding at the end of the year had a weighted average remaining contractual life of 494 days (2019: 495 days).

24. Related party transactions
24a. Subsidiaries
The principal subsidiaries of the PetroNor E&P Limited group, all of which have been included in these consolidated financial statements, are as follows:

			Proportion of effective ownership interest at 31 December	
Name	Country of incorporation	Principal place of business	2020	2019
PetroNor E&P Ltd	Cyprus	Cyprus	**100%**	100%
PetroNor E&P AS	Norway	Norway	**100%**	100%
PetroNor E&P Services Ltd	United Kingdom	United Kingdom	**100%**	100%
PetroNor E&P Nigeria Ltd	Nigeria	Nigeria	**100%**	100%
AJE Production AS	Norway	Norway	**100%**	-
Hemla Africa Holding AS	Norway	Norway	**70.707%**	70.707%
Hemla E&P Congo SA	Congo	Congo	**52.50%**	52.50%
African Petroleum Corporation Ltd	Cayman Islands	United Kingdom	**100%**	100%
PetroNor E&P Gambia Ltd	Cayman Islands	The Gambia	**100%**	100%
African Petroleum Senegal Ltd	Cayman Islands	Senegal	**90%**	90%
African Petroleum Senegal SAU	Senegal	Senegal	**100%**	100%
APCL Gambia BV	Netherlands	The Gambia	**100%**	100%

Notes to the Consolidated Financial Statements
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Material non-controlling interests
Set out below is summarised financial information for each subsidiary that has non-controlling interests that are material to the group. The amounts disclosed for each subsidiary are before inter-company eliminations.

Summarised statement of financial position

	Hemla E&P Congo SA		Hemla Africa Holding AS	
	2020 USD' 000	2019 USD' 000	2020 USD' 000	2019 USD' 000
Current asset	**42,019**	38,106	**30,514**	26,291
Current liabilities	**19,054**	20,553	**4,026**	13,092
Current net assets	**22,965**	17,553	**26,488**	13,199
Non-current assets	**27,417**	27,182	**1,188**	1,188
Non-current liabilities	**21,986**	14,373	**11,000**	-
Non-current net assets/(liabilities)	**5,431**	12,809	**(9,812)**	1,188
Net assets	**28,396**	30,362	**16,676**	14,387
Accumulated NCI	**7,312**	7,818	**4,885**	4,214

Summarised statement of comprehensive income

	Hemla E&P Congo SA		Hemla Africa Holding AS	
	2020 USD' 000	2019 USD' 000	2020 USD' 000	2019 USD' 000
Revenue	**67,543**	102,760	**150**	-
Profit for the period	**18,034**	27,430	**15,957**	9,950
Other comprehensive income	**-**	-	**(316)**	-
Total comprehensive income for the year	**18,034**	27,430	**15,641**	9,950
Profit allocated to NCI	**8,556**	13,029	**4,674**	2,915
Dividends paid to NCI	**5,150**	5,665	**3,912**	-

Summarised cash flows

	Hemla E&P Congo SA		Hemla Africa Holding AS	
	2020 USD' 000	2019 USD' 000	2020 USD' 000	2019 USD' 000
Cash flows from operating activities	**8,245**	49,675	**2,877**	(1,608)
Cash flows from investing activities	**(4,606)**	(12,276)	**-**	-
Cash flows from financing activities	**(8,047)**	(22,000)	**(11,295)**	5,858
Net (decrease)/increase in cash and cash equivalents	**(4,408)**	15,399	**(8,418)**	4,250

Notes to the Consolidated Financial Statements
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24b. Key management personnel remuneration
Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Group, including the Directors and Company Secretary listed on page 9, and the following other key personnel:

Knut Søvold	Chief Executive Officer
Gerhard Ludvigsen	Business Development Manager
Claus Frimann-Dahl	Chief Technical Officer
Emad Sultan	Strategy and Contracts Manager
Michael Barrett	Exploration Manager
Chris Butler	Group Financial Controller

Post year-end remuneration
As at the approval date of this report the base salary and fees for the following members of key management is as follows:

Individual	Title	Group Entity	Base salary and fees/per annum	Total base salary and fees USD equivalent
E Alhomouz	Chairman [1]	PetroNor E&P AS	USD 240,000	360,000
	Non-Executive Director	Hemla E&P Congo SA	USD 120,000	
J Pace	Non-Executive Director	PetroNor E&P Ltd	NOK 250,000	30,150
J Iskander	Non-Executive Director		Nil	Nil
A Neuling	Non-Executive Director	PetroNor E&P Ltd	AUD 48,000	37,300
R Steinepreis	Non-Executive Director	PetroNor E&P Ltd	AUD 48,000	37,300
I Tybring-Gjedde	Non-Executive Director	PetroNor E&P AS	NOK 250,000	30,150
G Kielland	Non-Executive Director	PetroNor E&P AS	NOK 250,000	30,150
K Søvold	Chief Executive Officer	PetroNor E&P AS	NOK 1,860,000	290,300
	Non-Executive Director	Hemla E&P Congo SA	USD 66,000	
E Sultan	Strategy & Contracts Manager [1]	PetroNor E&P AS	USD 120,000	120,000
C Frimann-Dahl	Chief Technical Officer	PetroNor E&P AS	NOK 1,500,000	186,900
M Barrett	Exploration Manager	PetroNor E&P Services Ltd	GBP 150,000	208,350
C Butler	Group Financial Controller	PetroNor E&P Services Ltd	GBP 115,000	159,700
A Hicks	Company Secretary	PetroNor E&P Ltd	AUD 24,000	18,650

[1] Fees are charged by related party Petromal LLC and are not paid to the individual; above figures represent the company's fair value estimate of associated costs for the individual's services

FX rates used as at 28 April 2021
NOK 1.00 : USD 0.12060
GBP 1.00 : USD 1.3890

Notes to the Consolidated Financial Statements
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Remuneration of key management personnel

2020	Designation	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Termination fees USD	Total USD
Management						
K Søvold	Exec Director & CEO	254,107	832	22,114	-	277,053
J Pace [1]	Exec Director & CEO	83,039	1,318	-	448,618	532,975
S West [2]	Exec Director & CFO	58,884	2,030	5,888	346,077	412,879
G Ludvigsen	Exec Director & Business Development Manager	254,107	832	23,471	-	278,410
C Frimann-Dahl	Chief Technical Officer	200,432	747	18,962	-	220,141
M Barrett	Exploration Manager	246,595	2,131	-	-	248,726
C Butler	Group Financial Controller	147,766	5,766	14,777	-	168,309
E Sultan	Strategy & Contracts Manager Related party fees [3]	232,500	-	-	-	232,500
A Hicks	Company Secretary	23,995	-	-	-	23,995
		1,501,425	**13,656**	**85,212**	**794,695**	**2,394,988**
Directors' remuneration for PetroNor E&P Ltd Australia						
E Alhomouz	Non-Exec Chairman Related party fees [3]	255,000	-	-	-	255,000
J Iskander	Non-Exec Director	-	-	-	-	-
Jens Pace [1]	Non-Exec Director	-	-	-	-	-
A Neuling [4]	Non-Exec Director	24,403	-	-	-	24,403
R Steinepreis [4]	Non-Exec Director	22,600	-	-	-	22,600
I Smines Tybring Gjedde [5]	Non-Exec Director	17,565	-	-	-	17,565
T Turner [6]	Non-Exec Director	1,760	-	-	-	1,760
D King [7]	Non-Exec Director	(3,000)	-	-	-	(3,000)
		318,328	**-**	**-**	**-**	**318,328**
Directors' remuneration for subsidiaries						
E Alhomouz	Non-Exec for HEPCO	120,000	-	-	-	120,000
K Søvold	Non-Exec for HEPCO	66,000	-	-	-	66,000
G Ludvigsen	Non-Exec for HEPCO	66,000	-	-	-	66,000
		252,000	-	-	-	**252,000**
TOTAL		**2,071,753**	**13,656**	**85,212**	**794,695**	**2,965,316**

[1] On 29 February 2020, Mr. Pace resigned as CEO but remained on the board as a Non-Exec Director. Mr. Pace agreed to waive his Non-Exec Director remuneration for one year in recognition of the termination fees agreed for resigning as CEO.
[2] Resigned 29 February 2020
[3] Remuneration is not paid to the individual, as fees are included in a monthly lump sum charged by related party Petromal LLC, above figures represent the company's fair value estimate of associated costs for the individual's services.
[4] Appointed 6 April 2020
[5] Appointed 29 May 2020
[6] Resigned 8 February 2020
[7] Resigned 1 February 2020

Notes to the Consolidated Financial Statements
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2019	Designation	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Termination fees USD	Total USD
Management						
K Søvold	Exec Director & COO	358,551	1,989	24,350	-	384,891
J Pace [1]	Exec Director & CEO	159,716	2,076	-	-	161,792
S West [1]	Exec Director & CFO	113,257	1,034	11,326	-	125,617
G Ludvigsen	Business Development Manager	360,119	466	25,829	-	386,414
C Frimann-Dahl	Chief Technical Officer	226,678	-	-	-	226,678
M Barrett [1]	Exploration Manager	125,491	506	-	-	125,997
C Butler [1]	Group Financial Controller	48,239	2,209	4,824	-	55,272
E Sultan [2]	Strategy & Contracts Manager Related party fees [2]	301,239	-	-	-	301,239
A Hicks [1]	Company Secretary	5,466	-	-	-	5,466
		1,698,756	**8,280**	**66,329**	**-**	**1,773,366**
Directors' remuneration for PetroNor E&P Ltd Australia						
E Alhomouz	Non-Exec Chairman Related party fees [2]	361,488	-	-	-	361,488
J Iskander [3]	Non-Exec Director	-	-	-	-	-
T Turner [1]	Non-Exec Director	5,456	-	-	-	5,456
D King [1]	Non-Exec Director	12,000	-	-	-	12,000
B Moe [1]	Non-Exec Director	11,000	-	-	-	11,000
		389,944	**-**	**-**	**-**	**389,944**
Directors' remuneration for subsidiaries						
E Alhomouz	Non-Exec for HEPCO	120,000	-	-	-	120,000
K Søvold	Non-Exec for HEPCO	66,000	-	-	-	66,000
G Ludvigsen	Non-Exec for HEPCO	66,000	-	-	-	66,000
A Georghiou [5] [6]	Non-Exec for PN Cyprus	6,143	-	-	-	6,143
H Marshad [5]	Non-Exec for PN Cyprus	5,500	-	-	-	5,500
N Kouyialis [5] [6]	Non-Exec for PN Cyprus	6,250	-	-	-	6,250
		269,893	**-**	**-**	**-**	**269,893**
TOTAL		**2,358,593**	**8,280**	**66,329**	**-**	**2,433,203**

[1] Remuneration from 30 August 2019 to 31 December 2019, i.e., after completion of reverse takeover
[2] Remuneration is not paid to the individual, as fees are included in a monthly lump sum charged by related party Petromal LLC, above figures represent the company's fair value estimate of associated costs for the individual's services.
[4] Appointed 30 August 2019 and agreed to waive his remuneration as Non- Executive Director as appointed by Petromal LLC
[5] Appointed 17 April 2019
[6] Individual ceased to be part of key management upon completion of reverse takeover on 30 August 2019

During 2020, Employer's social taxes of USD 204,700 (2019: USD 169,118) were payable for the key management remuneration.

Notes to the Consolidated Financial Statements
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Share holdings by Directors and other Key Management Personnel

	Balance 1 January 2020	Shares purchased	Granted as remuneration	Net change other	Balance 31 December 2020
K Søvold jointly with G Ludvigsen [1]	444,237,596	-	-	(210,681,739)	233,555,857
K Søvold [2]	-	-	-	45,000,000	45,000,000
G Ludvigsen [3]	-	-	-	60,000,000	60,000,000
J Pace	1,498,938	-	-	-	1,498,938
S West [4]	1,377,554	-	-	(1,377,554)	-
M Barrett	1,151,667	-	-	-	1,151,667
C Butler	234,296	-	-	-	234,296
C Frimann-Dahl	50,000	-	-	-	50,000
D King	30,000	-	-	(30,000)	-
T Turner	4,167	-	-	(4,167)	-
	448,584,218	**-**	**-**	**(107,093,460)**	**341,490,758**

[1] Shares are held by NOR Energy AS, a company controlled jointly by K Søvold and G Ludvigsen through an indirect beneficial interest.
[2] Shares are held by Gulshagan III AS, a company controlled by K Søvold through an indirect beneficial interest.
[3] 45,000,000 shares are held by Nedi Hagan AS, a company controlled by G Ludvigsen through an indirect beneficial interest. A further 15,000,000 shares are held by Pust for Livet A, a company controlled by a close associate of G Ludvigsen.
[4] Shares are held by Cresthaven Pty Ltd, a company controlled by S West through an indirect beneficial interest.

As at 31 December 2020, Eyas Alhomouz held no shares personally but holds influence over 371,961,246 shares (2019: 371,961,246 shares) as the CEO of significant shareholder Petromal LLC.

Other members of key management not included in the above table held no shares during the current year.

No warrants or options were held by Directors and other Key Management Personnel during the current year.

24c. Significant Shareholders

Shareholder	Place of incorporation	31 December 2020 Ownership	31 December 2019 Ownership
Petromal LLC – Sole Proprietorship LLC	UAE	**38.28%**	38.28%
NOR Energy AS	Norway	**24.03%**	45.72%

After the year end, a further 84,363,636 shares were issued for a private placement. Plus, NOR Energy AS divested another 90,000,000 shares, with 45,000,000 to a company controlled by K Søvold and 45,000,000 to a company controlled by G Ludvigsen. Consequently, at the date of signing this report, NOR Energy AS have 13.59% ownership. But if as expected, the Symero Transaction is completed during May 2021, NOR Energy AS will increase their effective to 22.04% through their control of Symero Ltd.

Notes to the Consolidated Financial Statements
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24d. Transactions and period-end balances with related parties
Transactions with related parties included in the consolidated statement of comprehensive income:

	2020 USD'000	2019 USD'000
Nor Energy AS subsidiary company – loan write-off [1]	**-**	5,305
Nor Energy AS – charge back of expenses	**-**	103
Petromal – Sole Proprietorship LLC	**587**	1,088
Administrative expenses	**587**	6,496

[1] During 2017, Hemla Africa Holding AS provided a loan facility of USD 6 million to a Nor Energy AS subsidiary company, for which the borrower had an option to drawdown in one or more instalments. The loan did not carry any interest and was repayable on demand. However, prior to the merger on 30 August 2019, the outstanding balance of USD 5.3 million was written off to administrative expenses.

Balances due from and due to related parties disclosed in the consolidated statement of financial position:

	2020 USD'000	2019 USD'000
Loan receivable from MGI International S.A. [1]	**3,639**	5,639
Total receivables from related parties (Note 12)	**3,639**	5,639
Other payable to Nor Energy AS	**3,378**	5,783
Other payable to Petromal – Sole Proprietorship LLC	**2,030**	4,534
Other payable to Symero Ltd.	**108**	-
Other payable to MGI International S.A.	**6,178**	3,467
Total payables to related parties (Note 18)	**11,694**	13,784
Loan payable Symero Ltd	**3,912**	-
Loan payable to related parties (Note 19)	**3,912**	-

[1] During 2018, Hemla Africa Holding AS (HAH AS) provided a loan of USD 7 million to MGI International SA, (minority shareholder in Hemla E&P Congo SA (HEPCO). The loan will be repaid directly by HEPCO to HAH AS from its yearly dividends being 25% of MGI's share of dividend in the first year and 40% thereafter. The loan does not carry any interest unless there is a breach of any clause of the loan agreement in which case 4% p.a. will be accrued on the outstanding amount of loan.

Amounts due from / to related parties included in the consolidated statement of financial position (other than the loans to related parties) are interest-free and have no fixed repayment terms.

25. Risk Management
The Group's principal financial liabilities comprise accounts payable and amounts due to related parties. The main purpose of these financial instruments is to manage short-term cash flow and raise finance for the Group's capital expenditure program. The Group has various financial assets such as accounts receivable and cash.

It is, and has been throughout the year ending 31 December 2020, the Group's policy that no speculative trading in derivatives shall be undertaken.

The main risks that could adversely affect the Group's financial assets, liabilities or future cash flows are credit risk, liquidity risk, interest rate risk and foreign currency risk. The management reviews and agrees policies for managing each of these risks which are summarized below.

The following discussion also includes a sensitivity analysis that is intended to illustrate the sensitivity to changes in the market variables on the Group's financial instruments and shows the impact on profit or loss and shareholders' equity, where applicable. Financial instruments affected by market risk include accounts receivable, accounts payable and accrued liabilities.

The sensitivity has been prepared for periods ending 31 December 2020 using the amounts of debt and other financial assets and liabilities held as at those reporting dates.

Notes to the Consolidated Financial Statements
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Credit risk
Credit risk refers to the risk that a counterparty will default on its contractual obligations resulting in financial loss to the Group. As at 31 December 2020, the Group's maximum exposure to credit risk without taking into account any collateral held or other credit enhancements, which will cause a financial loss to the Group due to failure to discharge an obligation by the counterparties and financial guarantees provided by the Group arises from the carrying amount of the respective recognised financial assets as stated in the statement of financial position.

To minimise credit risk, the Group has tasked its management to develop and maintain the Group's credit risk gradings to categorise exposures according to their degree of risk of default. The credit rating information is supplied by independent rating agencies where available and, if not available, the management uses other publicly available financial information and the Group's own trading records to rate its major customers and other debtors. The Group's exposure and the credit ratings of its counterparties are continuously monitored, and the aggregate value of transactions concluded is spread amongst approved counterparties.

The Company's current credit risk grading framework comprises the following categories:

Category	Description	Basis for recognising expected credit losses
Performing	The counterparty has a low risk of default and does not have any past-due amounts	12-month ECL
Doubtful	Amount is >30 days past due or there has been a significant increase in credit risk since initial recognition	Lifetime ECL – not credit-impaired
In default	Amount is >90 days past due or there is evidence indicating the asset is credit-impaired	Lifetime ECL – credit-impaired
Write-off	There is evidence indicating that the debtor is in severe financial difficulty and the Company has no realistic prospect of recovery	Amount is written off

The tables below detail the credit quality of the Company's financial assets as well as the Company's maximum exposure to credit risk by credit risk rating grades.

	Notes	External credit rating	Internal credit rating	12-month or lifetime ECL	Gross carrying amount USD'000	Loss allowance USD'000	Net carrying amount USD'000
31 December 2020							
Trade receivables	12	N/a	(i)	Lifetime ECL	**5,408**	**-**	**5,408**
Due from related parties	12, 24d	N/a	-	Lifetime ECL	**3,639**	**-**	**3,639**
Advance against decommissioning cost	12	N/a	-	Lifetime ECL	**21,260**	**-**	**21,260**
Cash and cash equivalents	13	Aa3/B	N/a	12-month ECL	**14,113**	**-**	**14,113**
31 December 2019							
Trade receivables		N/a	(i)	Lifetime ECL	4,013	-	4,013
Due from related parties		N/a	-	Lifetime ECL	5,639	-	5,639
Advance against decommissioning cost		N/a	-	Lifetime ECL	14,464	-	14,464
Cash and cash equivalents		Aa3/B	N/a	12-month ECL	27,891	-	27,891

(i) For trade receivables and amounts due from related parties, the Group has applied the simplified approach in IFRS 9 to measure the loss allowance at lifetime ECL. The expected credit losses are estimated using a provision matrix by reference to past default experience of the debtor and an analysis of the debtor's current financial position, adjusted for factors that are specific to the debtors, general economic conditions of the industry in which the debtors operate and an assessment of both the current as well as the forecast direction of conditions at the reporting date.

Notes to the Consolidated Financial Statements
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Liquidity risk
The Group seeks to limit its liquidity risk by ensuring financial support is available from the shareholders. The Group's terms of sales requires amounts to be paid within 45 to 60 days of the date of approval of progress billings. Trade payables are normally settled within 90 to 120 days of the date of receipt of invoice.

The table below summarises the maturity profile of the Group's financial liabilities at 31 December 2020 based on contractual undiscounted payments.

USD'000	Note	On demand	Less than 1 month	Between 1 and 3 months	Between 3 months and 1 year	More than 1 year	Total
31 December 2020							
Trade accounts payable	19	**544**	**479**	**4,203**	**-**	**-**	**5,226**
Amounts due to related parties	24d	**11,986**	**-**	**-**	**-**	**-**	**11,986**
Loan payable	20	**-**	**-**	**-**	**4,000**	**14,912**	**18,912**
		12,530	**479**	**4,203**	**4,000**	**14,912**	**36,124**

USD'000	Note	On demand	Less than 1 month	Between 1 and 3 months	Between 3 months and 1 year	More than 1 year	Total
31 December 2019							
Trade accounts payable	19	616	1,580	2,483	10,130	-	14,809
Amounts due to related parties	24d	13,784	-	-	-	-	13,784
Loan payable	20	-	588	1,176	11,176	-	12,941
		14,400	2,168	3,659	21,306	-	41,535

The Company had USD 14.1 million (2019: 27.0 million) in unrestricted cash as of 31 December 2020. Should additional funding be required in the future for additional capital expenditure for new development phases or working capital requirements, the Company has various alternatives available which it can explore to fulfil such additional requirements. The options include, amongst others, debt financing, offtake prepayment structures. As a result, the financial statements have been prepared under the assumption of going concern and realisation of assets and settlement of debt in normal operations.

Interest rate risk
The Group is exposed to interest rate risk on its interest-bearing assets and liabilities and seeks to limit this risk by obtaining favourable interest rates.

	31 December 2020		31 December 2020	
	+150bp USD'000	-150bp USD'000	+150bp USD'000	-150bp USD'000
Loans payable	**(284)**	**284**	(194)	194

Notes to the Consolidated Financial Statements
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Currency risk
The Group operates internationally and is exposed to risk arising from various currency exposures, primarily with respect to the Norwegian Kroner (NOK), and the Great British Pound (GBP). The Group has transactional currency exposures. Such exposure arises from sales or purchases in currencies other than the respective functional currency.

The Group reports its consolidated results in USD; any change in exchange rates between its operating subsidiaries' functional currencies and the USD affects its consolidated statement of comprehensive income and statement of financial position when the results of those operating subsidiaries are translated into USD for reporting purposes.

Group companies are required to manage their foreign exchange risk against their functional currency.
A 20% strengthening or weakening of the USD against the following currencies at 31 December 2019 would have increased / (decreased) equity and profit or loss by the amounts shown below.

The Group's assessment of what a reasonable potential change in foreign currencies that it is currently exposed to have been changed as a result of the changes observed in the world financial markets. This hypothetical analysis assumes that all other variables, including interest rates and commodity prices, remain constant.

	31 December 2020		31 December 2019	
	+20% USD'000	-20% USD'000	+20% USD'000	-20% USD'000
USD vs NOK				
Cash	**58**	**(58)**	45	(45)
Receivables	**61**	**(61)**	99	(99)
Payables	**(25)**	**25**	(246)	246
	94	**(94)**	(102)	102
USD vs GBP				
Cash	**4**	**(4)**	3	(3)
Receivables	**2**	**(2)**	11	(11)
Payables	**(42)**	**42**	(119)	119
	(36)	**36**	(105)	105

Capital risk
The primary objective of the Group's capital management is to continuously evaluate measures to strengthen its financial basis and to ensure that the Group is fully funded for its committed 2020 activities. The Group manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or change the capital structure, the Group may adjust the amount of dividend payments to shareholders, return capital to shareholders or issue new shares. The Group has no significant debt arrangements in place and has the flexibility to source conventional debt capital from the markets.

The Group is continuously evaluating the capital structure, with the aim of having an optimal mix of equity and debt capital to reduce the Group's cost of capital and looking at avenues to procure capital in the forthcoming year.

26. Financial instruments – Fair values
Financial instruments comprise financial assets and financial liabilities.

Financial assets consist of bank balances and cash, amounts due from related parties and trade and some other receivables. Financial liabilities consist of amounts due to related parties, loans payable, trade account payables and some other liabilities.

The fair values of the Group's financial instruments are not materially different from their carrying amounts at the reporting date largely due to the short-term maturities of these instruments.

Notes to the Consolidated Financial Statements
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27. Commitments and contingencies
Commitments
Exploration commitments
The Company has entered into obligations in respect of its exploration projects. Outlined below are the minimum expenditures required as at 31 December

	2020 USD'000	2019 USD'000
Within one year [1]	**40,000**	40,000

[1] The commitment in Senegal includes USD 40 million for an exploration well in each licence, however this assumes that the Company is successful in retaining the legal title for these licences and that the Company then drills these wells with 90% equity.

Contingencies
There are no contingencies as of the year end (2019: nil).

28. Parent entity financial information
i. Summary financial information
The individual financial statements of the parent entity show the following aggregate amounts:

	2020 USD'000	2019 USD'000
Statement of financial position		
Current assets	**20,149**	16,403
Non-current assets	**104,027**	104,027
Total assets	**124,176**	120,430
Current liabilities	**(15,971)**	(15,559)
Non-current liabilities	**(3,912)**	-
Total liabilities	**(19,883)**	(15,559)
Net Assets	**104,293**	104,871
Shareholders' equity		
Issued capital	**1,130,901**	1,130,901
Reserves	**29,391**	29,391
Accumulated losses	**(1,055,998)**	(1,055,421)
	104,293	104,871
Net loss for the year	**(577)**	(1,357)
Total comprehensive loss	**(577)**	(1,357)

ii. Guarantees entered into by the parent entity
In support of various subsidiaries, the listed top company PetroNor E&P Limited has provided the following guarantees:

PetroNor E&P Gambia Ltd is required to place a performance bond of USD 1 million in favour of the Gambian Government.

PetroNor E&P Services Ltd employed the former CFO and CEO of the group, Stephen West and Jens Pace respectively. Termination benefits have been guaranteed amounting to USD 273,760 as at 31 December 2020.

During the year, Hemla Africa Holding AS entered into a loan agreement with Acqua Diversified Holdings SPC for USD 15 Million. The Parent Company has provided a corporate guarantee to Acqua Diversified Holdings SPC for the repayment of this loan. Amount outstanding as of 31 December 2020 was USD 15 Million.

No financial guarantees in respect of bank overdrafts, decommissioning liabilities and loans of subsidiaries were provided in the year ended 31 December 2019.

Notes to the Consolidated Financial Statements
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29. Events subsequent to reporting date

Due to a breach of covenants under the loan agreement between Hemla Africa Holding AS ("HAH") and MGI International SA, the commercial court, Tribunal de Commerce de Pointe Noire, in Congo has awarded HAH 9,900 shares in Hemla E&P Congo SA ("HEPCO"), increasing HAH's share of HEPCO with 9.9%, equivalent to PetroNor increasing its indirect interest in PNGF Sud with 1.40% at a cost of approximately USD 4 million. As per Congolese law, the award can be challenged in a higher court, and if so the timing of such further appeal and any final outcome are uncertain.

On 29 January 2021, Gerhard Ludvigsen resigned as an Executive Director and was replaced on 1 February 2021 by Gro Kielland appointed as a Non-Executive Director.

A CPR update prepared by AGR Petroleum Services AS on the Company's PNGF Sud asset in Congo was released on 11 March 2021. The update represented an increase of approximately 28% and 49% for 2P and 2C respectively on a gross basis.

On 12 March 2021, the Company raised NOK 340 million of new equity through a Private Placement of 309,090,909 new shares in the Company. The Private Placement received strong interest from new investors, including institutional investors and private family offices in Norway and internationally. Petromal Sole Proprietorship LLC and related group companies ("Petromal"), the Company's main shareholder owning 38.28% of all issued and outstanding shares in the Company, subscribed for Offer Shares at the Offer Price for an amount of NOK 130.2 million, which corresponds to their 38.28% pro-rata share of the Private Placement.

The Private Placement will generate NOK 187.4 million (USD 22.1 million) in cash and NOK 152.6 million (USD 18.0 million) as in-kind consideration for contingent acquisition of all of Symero Limited's ("Symero") shares in Hemla Africa Holding AS ("HAH") (the "Symero Transaction"). Symero is owned by NOR Energy AS, a company owned by Knut Søvold, CEO of the Company, and Gerhard Ludvigsen.

The net cash proceeds from the Private Placement will be used to finance drilling of infill wells and other increased oil recovery initiatives on PNGF Sud and general corporate purposes. The Private Placement is divided into two tranches: Tranche 1 ("Tranche 1") consisting of Offer Shares for NOK 92.8 million have been allocated to existing and new investors, including Petromal. The remaining Offer Shares have been subscribed by and allocated to Symero (for an amount equal to NOK 152.6 million (USD 18 million) ("Tranche 2a") and Petromal (for an amount equal to NOK 94.6 million) in order to retain its ~38.28% ownership ("Tranche 2b").

The Company released a Notice of Meeting for an EGM to be held on the 4 May 2021, as the Symero Transaction is a related party transaction and subject to approval by ordinary resolution. An independent expert report was attached to the Notice as required pursuant the Australian Corporations Act.

The Company is contemplating to carry out a subsequent offering of new shares without tradable subscription rights of up to 60,000,000 new shares in the Company (equivalent to NOK 66 million) towards existing shareholders of the Company as of close of trading on Oslo Euronext Expand on 11 March 2021, shareholders of record on 15 March 2021. A combined prospectus for listing of the Offer Shares in Tranche 2a and Tranche 2b and for the offering of shares in the contemplated Subsequent Offering is expected to be published during May 2021.

On 5 April 2021, the Company announced that the arbitration proceedings for the Group's interests in Senegal were to resume despite numerous progressive meetings with the relevant authorities to reach a mutually beneficial solution.

On 26 April 2021, the Company announced that the regulatory approval for acquisition of SPE Guinea Bissau AB had been received, satisfying the condition precedent for completion.

Except for the above, the Company has not identified any events with significant accounting impacts that have occurred between the end of the reporting period and the date of this report.

30. Summary of accounting policies

Accounting policies are selected and applied in a manner which ensures that the resulting financial information satisfies the concepts of relevance and reliability, thereby ensuring that the substance of the underlying transactions or other events is reported.

The following is a summary of the material accounting policies adopted by the Group in the preparation of the financial report. The accounting policies have been consistently applied, unless otherwise stated.

Notes to the Consolidated Financial Statements
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30a. Adoption of new and revised accounting standards

In the current period, the Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') that are relevant to its operations and effective for reporting periods beginning on 1 January 2020. The Group has not elected to early adopt any new standards or amendments.

The Group applied AASB 16 Leases for the first time. The nature and effect of the changes as a result of adoption of this new accounting standard is described below.

AASB 16 Leases

AASB 16 supersedes AASB 117 Leases, Interpretation 4 Determining whether an Arrangement contains a Lease, Interpretation 115 Operating Leases-Incentives and Interpretation 127 Evaluating the Substance of Transactions Involving the Legal Form of a Lease. The standard sets out the principles for the recognition, measurement, presentation, and disclosure of leases and requires lessees to account for most leases on the balance sheet.

Lessor accounting under AASB 16 is substantially unchanged from AASB 117. Lessors will continue to classify leases as either operating or finance leases using similar principles as in AASB 117. Therefore, AASB 16 did not have an impact for leases where the Group is the lessor.

The Group has opted for the simplified modified retrospective application permitted by AASB 16 upon adoption of the new standard. The Company does not restate any comparative information. During first time application of AASB 16 to operating leases, the right of use have been measured at the amount of lease liability adjusted by the amount of any prepaid or accrued payments recognised in the statement of financial position immediately before the date of initial application.

Impact of the new definition of lease

The Group has made use of the practical expedient available on transition to AASB 16 not to reassess whether a contract is or contains a lease. Accordingly, the definition of a lease in accordance with AASB 117 will continue to be applied to leases entered or modified before 1 January 2019. The change in definition of a lease mainly relates to the concept of control. AASB 16 determines whether a contract contains a lease on the basis of whether the customer has the right to control the use of an identified asset for a period of time in exchange for consideration. The Group applies the definition of a lease and related guidance set out in AASB 16 to all lease contracts entered into or modified on or after 1 January 2019 (whether it is a lessor or a lessee in the lease contract). In preparation for the first-time application of AASB 16, the Group has carried out an implementation project. The project has shown that the new definition in AASB 16 will not change significantly the scope of contracts that meet the definition of a lease for the Group.

Impact on Lessee Accounting

Former operating leases

AASB 16 changes how the Group accounts for leases previously classified as operating leases under AASB 117, which were off-balance-sheet. Applying AASB 16, for all leases (except as noted below), the Group:

- recognises right-of-use assets and lease liabilities in the statement of financial position, initially measured at the present value of future lease payments;
- recognises depreciation of right-of-use assets and interest on lease liabilities in the statement of profit or loss; and
- separates the total amount of cash paid into a principal portion (presented within financing activities) and interest (presented within operating activities) in the statement of cash flows.

Lease incentives (e.g., free rent period) are recognised as part of the measurement of the right-of-use assets and lease liabilities whereas under AASB 17 they resulted in the recognition of a lease incentive liability, amortised as a reduction of rental expense on a straight-line basis.

Under AASB 16, right-of-use assets are tested for impairment in accordance with AASB 136 Impairment of Assets. This replaces the previous requirement to recognise a provision for onerous lease contracts. For short term leases (lease term of 12 months or less) and leases of low-value assets (such as personal computers and office furniture), the Company has opted to recognise a lease expense on a straight-line basis as permitted by AASB 16. This expense is presented within other expenses in the statement of profit or loss.

The main difference between AASB 16 and AASB 117 with respect to assets formerly held under a finance lease is the measurement of residual value guarantees provided by a lessee to a lessor. AASB 16 requires that the Company recognises as part of its lease liability only the amount expected to be payable under a residual value guarantee, rather than the maximum amount guaranteed as required by AASB 117. This change did not have a material effect on the Group's financial statements.

Notes to the Consolidated Financial Statements
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Financial impact of initial application of AASB 16
The Directors note that the impact of the initial application of AASB 16 is not material to the overall financials statement of the Group.

The application of AASB 16 to leases previously classified as operating leases under AASB 117 resulted in the recognition of right-of-use assets and leases liabilities. It resulted in a decrease in other expense and an increase in depreciation and amortisation expense and in interest expense.

The lease incentives liability previously recognised with respect to operating leases has been derecognised and the amount factored in the measurement of the right-of-use assets and lease liabilities.

The Directors note that the impact of the initial application of the Standards and Interpretation is not yet known or is not reasonably estimable and is currently being assessed. At the date of authorisation of the financial statements, the Standards and Interpretations that were issued but not yet effective are listed below.

Standard/Interpretation	Effective
AASB 2020-5 Amendments to AASs – Insurance Contracts	1 Jan 2021
AASB 2020-8 Amendments to AASs – Interest Rate Benchmark Reform – Phase 2	1 Jan 2021
AASB 2020-7 Amendments to AASs – Covid-19-Related Rent Concessions: Tier 2 Disclosures	1 Jul 2021
AASB 1060 General Purpose Financial Statements – Simplified Disclosures for For-Profit and Not- for-Profit Tier 2 Entities	1 Jul 2021
AASB 2020-2 Amendments to AASs – Removal of Special Purpose Financial Statements for Certain For-Profit Private Sector Entities	1 Jul 2021
AASB 2020-3 Amendments to AASs – Annual Improvements 2018–2020 and Other Amendments ● Amendment to AASB 1, Subsidiary as a First-time Adopter ● Amendments to AASB 3, Reference to the Conceptual Framework ● Amendment to AASB 9, Fees in the '10 per cent' Test for Derecognition of Financial Liabilities ● Amendments to AASB 116, Property, Plant and Equipment: Proceeds before Intended Use ● Amendments to AASB 137, Onerous Contracts – Cost of Fulfilling a Contract ● Amendment to AASB 141, Taxation in Fair Value Measurements	1 Jan 2022
AASB 2014-10 Amendments to AASs – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture	1 Jan 2022
AASB 17 Insurance Contracts	1 Jan 2023
AASB 2020-1 Amendments to AASs – Classification of Liabilities as Current or Non-current	1 Jan 2023

At the date of authorisation of the financial statements, the following IASB Standards and IFRIC Interpretations were also in issue but not yet effective, although Australian equivalent Standards and Interpretations have not yet been issued.

None

30b. Consolidation
The consolidated financial statements comprise the financial statements of PetroNor E&P Limited ("the Company") and its subsidiaries for the year ended 31 December 2020 (together the Group).

Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:
- Power over the investee (i.e., existing rights that give it the current ability to direct the relevant activities of the investee)
- Exposure, or rights, to variable returns from its involvement with the investee, and
- The ability to use its power over the investee to affect its returns

When the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:
- The contractual arrangement with the other vote holders of the investee
- Rights arising from other contractual arrangements
- The Group's voting rights and potential voting rights

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the statement of comprehensive income from the date the Group gains control until the date the Group ceases to control the subsidiary.

Notes to the Consolidated Financial Statements
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Profit or loss and each component of other comprehensive income (OCI) are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- Derecognises the assets (including goodwill) and liabilities of the subsidiary
- Derecognises the carrying amount of any non-controlling interests
- Derecognises the cumulative translation differences recorded in equity
- Recognises the fair value of the consideration received
- Recognises the fair value of any investment retained
- Recognises any surplus or deficit in profit or loss
- Reclassifies the parent's share of components previously recognised in OCI to profit or loss or retained earnings, as appropriate, as would be required if the Group had directly disposed of the related assets or liabilities.

30c Segment reporting

An operating segment is a component of an entity that engages in business activities from which it may earn revenues and incur expenses (including revenues and expenses relating to transactions with other components of the same entity), whose operating results are regularly reviewed by the entity's chief operating decision-makers to make decisions about resources to be allocated to the segments and assess their performance and for which discrete financial information is available. This includes start-up operations which are yet to earn revenues.

Operating segments have been identified based on the information available to chief operating decision-makers – being the Board and the executive management team.

Operating segments that meet the quantitative criteria as prescribed by AASB 8 are reported separately. However, an operating segment that does not meet the quantitative criteria is still reported separately where information about the segment would be useful to users of the financial statements.

Information about other business activities and operating segments that are below the quantitative criteria are combined and disclosed in a separate category called "all other segments".

30d Foreign currency translation

Functional and presentation currency

The Company has elected to use United States Dollars, being the functional currency of all major subsidiaries in the Group, as its presentation currency. Where the functional currencies of entities within the consolidated group differ from United States Dollars, they have been translated into United States Dollars. The functional currency of PetroNor E&P Limited is United States Dollars.

Transactions and balances

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the rate of exchange ruling at the reporting date and any gains or losses are recognised in the income statement.

Non-monetary items that are measured in terms of historical cost in the foreign currency are translated using the exchange rate as at the date of the initial transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined.

Translation of Group Companies' functional currency to presentation currency

On consolidation, the assets and liabilities of foreign operations are translated into United States Dollars at the rate of exchange prevailing at the reporting date and their income and expenditure are translated at exchange rates prevailing at the dates of the transactions. The exchange differences arising on translation for consolidation are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

30e. Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held at call with banks, other short-term highly liquid investments with original maturities of three months or less, and bank overdrafts. Bank overdrafts are shown within short-term borrowings in current liabilities on the Statement of Financial Position.

Notes to the Consolidated Financial Statements
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30f. Trade receivables
Trade receivables are amounts due from customers for goods sold or services performed in the ordinary course of business. They are generally due for settlement within 30 to 90 days and therefore are all classified as current. Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value. The group holds the trade receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

Trade receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the group, and a failure to make contractual payments for a period of greater than 120 days past due.

Impairment losses on trade receivables and contract assets are presented as net impairment losses within operating profit. Subsequent recoveries of amounts previously written off are credited against the same line item.

30g. Inventory
The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realisable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses. The cost of inventory includes all costs related to bringing the inventory to its current condition, including processing costs, labour costs, supplies, direct and allocated indirect operating overhead and depreciation expense, where applicable, including allocation of fixed and variable costs to inventory.

30h. Property plant and equipment
Oil & gas production assets

Oil and gas production assets are aggregated exploration and evaluation tangible assets and development expenditures associated with the production of proved reserves.

The cost of development and production assets also includes the cost of acquisitions and purchases of such assets, directly attributable overheads and the cost of recognising provisions for future restoration and decommissioning.

Where major and identifiable parts of the production assets have different useful lives, they are accounted for as separate items of property, plant and equipment. Costs of minor repairs and maintenance are expensed as incurred.

Depreciation

Oil and gas properties are depreciated using the unit-of-production method. Unit-of production rates are based on 1P proved reserves, which are oil, gas and other mineral reserves estimated to be recovered from existing facilities using current operating methods. Oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank.

Field infrastructure exceeding beyond the life of the field is depreciated over the useful life of the infrastructure using a straight-line method.

Property, plant and equipment not associated with exploration and production activities are carried at cost less accumulated depreciation. These assets are also evaluated for impairment. Depreciation of other assets is calculated on a straight-line basis as follows:

Computer equipment	20 - 33.33%
Furniture, fixtures & fittings	10 - 33.33%
Motor vehicles	20%

Notes to the Consolidated Financial Statements
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30i. Exploration and evaluation expenditure
Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. For each area of interest, expenditure incurred in the acquisition of rights to explore and all costs directly associated with holding the licence such as rental, training and corporate and social responsibility are capitalised as exploration and evaluation intangible assets. Signature bonuses required by licence agreements are capitalised as exploration and evaluation intangible assets. Other costs directly associated with the licence are expensed as incurred.

Exploration, evaluation and development expenditure is recorded at historical cost and allocated to cost pools on an area of interest. Expenditure on an area of interest is capitalised and carried forward where rights to tenure of the area of interest are current and:
- it is expected to be recouped through successful development and exploitation of the area of interest or alternatively by its sale; or
- exploration and evaluation activities are continuing in an area of interest but at reporting date have not yet reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves.

Accumulated costs in respect of areas of interest which are abandoned are written off in full against profit in the period in which the decision to abandon the area is made.

Projects are advanced to development status when it is expected that further expenditure can be recouped through sale or successful development and exploitation of the area of interest.

All capitalised costs are subject to commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the statement of profit or loss and other comprehensive income.

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties.

Proceeds from disposal or farm-out transactions of intangible exploration assets are used to reduce the carrying amount of the assets. When proceeds exceed the carrying amount, the difference is recognised as a gain. When the Group disposes of its full interests, gains or losses are recognised in accordance with the policy for recognising gains or losses on sale of plant, property and equipment.

30j. Borrowing costs
Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset are added to the cost of the asset during the period of time that is required to complete and prepare the asset for its intended use. Borrowing costs are capitalised to the extent that funds are borrowed specifically for the purpose of obtaining a qualifying asset. To the extent that funds are borrowed generally and used for the purpose of obtaining a qualifying asset, the amount of borrowing costs eligible for capitalisation is determined by applying a capitalisation rate to the expenditures on that asset. All other borrowing costs are expensed as incurred.

30k. Revenue
i. Revenue from petroleum products
Revenue from the sale of crude oil is recognised when a customer obtains control ("sales" or "lifting" method), normally this is when title passes at point of delivery. Revenues from production of oil properties are recognised based on actual volumes lifted and sold to customers during the period.

ii. Other revenue
Under a production sharing contract, where the group is required to pay profit oil tax and royalties on production of crude oil, such payments are settled in kind (where the government lift the crude it is entitled to). The Group presents a gross-up of the profit oil tax as an income tax expense with a corresponding increase in oil and gas revenues and any associated royalties are included in the cost of sales.

The Group assesses whether it acts as a principal or agent in each of its revenue arrangements. The Group has concluded that in all sales transactions it acts as a principal.

iii. Variable consideration
If the consideration in a contract includes a variable amount, the Group recognises this amount as revenue only to the extent that it is highly probable that a significant reversal will not occur in the future.

iv. Interest
Interest revenue is recognised on a time-proportional basis using the effective interest method. This is a method of calculating the amortised cost of a financial asset and allocating the interest income over the relevant period using the effective interest rate, which is the rate that exactly discounts the estimated future cash receipts through the expected useful life of the financial asset to the net carrying amount of the financial asset.

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30l. Leases
The Group as lessee
The Group assesses whether contract is or contains a lease, at inception of the contract. The Group recognises a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low value assets. For these leases, the Group recognises the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased assets are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, the Group uses its incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise:
- fixed lease payments (including in-substance fixed payments), less any lease incentives;
- variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date;
- the amount expected to be payable by the lessee under residual value guarantees;
- the exercise price of purchase options, if the lessee is reasonably certain to exercise the options; and
- payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is presented as a separate line item in the statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using effective interest method) and by reducing the carrying amount to reflect the lease payments made.

The Group remeasures the lease liability (and makes a corresponding adjustment to the related right-of-use asset) whenever:
- the lease term has changed or there is a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.
- the lease payments change due to changes in an index or rate or a change in expected payment under a guaranteed residual value, in which cases the lease liability is remeasured by discounting the revised lease payments using the initial discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revise discount rate is used).
- a lease contract is modified, and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

The Group did not make any such adjustments during the periods presented.

The right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use of asset reflects that the Group expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

The right-of-use of assets are presented as a separate line in the statement of financial position.

The Group applies AASB 136 to determine whether a right-of-use asset is impaired and accounts for an identified impairment loss as described in the ‘Property, plant and equipment’ policy.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognised as an expense in the period in which the event or condition that triggers those payments occurs and are included in the line ‘Administrative expenses’ in the statement of profit or loss.

The Group as lessor
The Group enters into lease agreements as a lessor with respect to some of its investment properties.

Leases for which the Group is a lessor are classified as finance or operating leases. Whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee, the contract is classified as a finance lease. All other leases are classified as operating leases.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

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Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to accounting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

When a contract includes lease and non-lease components, the Group applies AASB 15 to allocate consideration under the contract to each component.

[Leases under AASB 17, applicable before 1 January 2020]

Leases are classified as finance leases whenever the terms of the lease transfer substantially all the risks and rewards of ownership to the lessee. All other leases are classified as operating leases.

The Group as lessor
Amounts due from lessees under finance leases are recognised as receivables at the amount of the Group's net investment in the leases. Finance lease income is allocated to accounting periods so as to reflect a constant periodic rate of return on the Group's net investment outstanding in respect of the leases.

Rental income from operating leases is recognised on a straight-line basis over the term of the relevant lease. Initial direct costs incurred in negotiating and arranging an operating lease are added to the carrying amount of the leased asset and recognised on a straight-line basis over the lease term.

The Group as lessee
Assets held under finance leases are initially recognised as assets of the Group at their fair value at the inception of the lease or, if lower, at the present value of the minimum lease payments. The corresponding liability to the lessor is included in the statement of financial position as a finance lease obligation.

Lease payments are apportioned between finance expenses and reduction of the lease obligation so as to achieve a constant rate of interest on the remaining balance of the liability. Finance expenses are recognised immediately in profit or loss, unless they are directly attributable to qualifying assets, in which case they are capitalised in accordance with the Group's general policy on borrowing costs. Contingent rentals are recognised as expenses in the periods in which they are incurred.

Operating lease payments are recognised as an expense on a straight-line basis over the lease term, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed. Contingent rentals arising under operating leases are recognised as an expense in the period in which they are incurred. In the event that lease incentives are received to enter into operating leases, such incentives are recognised as a liability. The aggregate benefit of incentives is recognised as a reduction of rental expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

30m. Taxes
The income tax expense or benefit for the period consists of two components: current and deferred tax.

The current income tax payable or recoverable is calculated using the tax rates and legislation that have been enacted or substantively enacted at year-end in each of the jurisdictions and includes any adjustments for taxes payable or recovery in respect of prior periods.

Deferred tax assets and liabilities are determined using the balance sheet liability method based on temporary differences between the carrying value of assets and liabilities for financial reporting purposes and their tax bases. In calculating the deferred tax assets and liabilities, the tax rates used are those that have been enacted or substantively enacted by year-end in each of the jurisdictions and that are expected to apply when the assets are recovered, or the liabilities are settled.

Revenue-based taxes
In addition to corporate income taxes, the Group's consolidated financial statements also include and recognise as income taxes, other types of taxes on net income such as certain revenue-based taxes.

Revenue-based taxes are accounted for under AASB 112 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government authority and the amount payable is based on taxable income — rather than physical quantities produced or as a percentage of revenue — after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are accrued and included in cost of sales. The revenue taxes, except royalty, payable by the Group are considered to meet the criteria to be treated as part of income taxes.

Notes to the Consolidated Financial Statements
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Production-sharing arrangements
According to the production-sharing arrangement (PSA) in certain licences, the share of the profit oil to which the Government is entitled in any calendar year in accordance with the PSA is deemed to include a portion representing the corporate income tax imposed upon and due by the Group. This amount will be paid directly by the government on behalf of the Group to the appropriate tax authorities.

The income tax expense
The current income tax is calculated using the PSA, paid in barrels and booked as income tax and also shown as revenue.

Sales tax
Revenues, expenses and assets are recognised net of the amount of sales tax except:

Where the sales tax incurred on a purchase of assets or services is not recoverable from the taxation authority, in which case, the sales tax is recognised as part of the cost of acquisition of the asset or as part of the expense item as applicable.

Receivables and payables that are stated with the amount of sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the statement of financial position.

Current and deferred tax balances attributable to amounts recognised directly in equity are also recognised directly in equity.

30n. Employee benefits
Provision is made for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required, and they are capable of being measured reliably. Provisions made in respect of employee benefits expected to be settled within 12 months are measured at their nominal values using the remuneration rate expected to apply at the time of settlement. Provisions made in respect of employee benefits, which are not due to be settled within 12 months are determined using the projected unit credit method.

30o. Trade and other payables
Trade and other payables are carried at amortised cost and due to their short-term nature, they are not discounted.

30p. Provisions
General
Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Group expects some or all of the provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is recognised through profit and loss net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as interest expense. The present obligation under onerous contracts is recognised as a provision.

Decommissioning liability
A decommissioning liability is recognised when the Group has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the obligation is also recognised as part of the cost of the related production plant and equipment. The amount recognised in the estimated cost of decommissioning, discounted to its present value. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to production plant and equipment. The unwinding of the discount on the decommissioning liability is included as a finance cost.

An escrow account is maintained by the operator of the licence and is governed by a joint operating agreement and the Congolese Government rules. The Group's share, paid against the decommissioning liability until the balance sheet date, is classified as an advance against decommissioning liability in current assets.

30q. Share capital
Contributed equity is recognised at the fair value of the consideration received by the Group, less any capital raising costs in relation to the issue.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

Notes to the Consolidated Financial Statements
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30r. Dividend distribution
Dividend distribution to the Company's shareholders is recognised as a liability in the Group's financial statements in the period in which the dividends are declared and appropriately authorised or approved by the Company's Shareholders' General Meeting. Interim dividends proposed by the Board of Directors are recognised as liabilities upon declaration.

30s. Share-based payments
The fair value of shares awarded is measured at the share price on the date the shares are granted. For options awarded, the fair value is measured at grant date using the Black-Scholes model. Shares and options which are subject to vesting conditions, are recognised over the estimated vesting period during which the holder becomes unconditionally entitled to the shares or options.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms had not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction; or is otherwise beneficial to the employee as measured at the date of modification.

30t. Financial instruments
A financial instrument is any contract that gives rise to a financial asset of any one entity and a financial liability or equity instrument of another entity.

i. Financial assets
Financial assets are classified, at initial recognition, as subsequently measured at amortised cost, fair value through other comprehensive income (OCI), and fair value through profit or loss, as appropriate.

The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Group's business model for managing them. With the exception of trade receivables that do not contain a significant financing component or for which the Group has applied the practical expedient, the Group initially measures a financial asset at its fair value plus, in the case of financial assets not subsequently measured at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.
In order for a financial asset to be classified and measured at amortised cost or fair value through OCI, it needs to give rise to cash flows that are solely payments of principal and interest (SPPI) on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level.

The Group's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both.

Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the marketplace (regular way trades) are recognised on the trade date, i.e., the date that the Group commits to purchase or sell the asset.

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognizes financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a 3rd party. This includes the derecognition of receivables for which discounting arrangements are entered into. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Subsequent measurement
For purposes of subsequent measurement, financial assets are classified in 4 categories:
- Financial assets at amortised cost (debt instruments)
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments)
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments)
- Financial assets at fair value through profit or loss

The Group has not designated any financial assets at fair value through profit or loss.

Financial assets at amortised cost (debt instruments)
The Group measures financial assets at amortised cost if both of the following conditions are met:
- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows;

And
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding;

Financial assets at amortised cost are subsequently measured using the effective interest (EIR) method and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

Notes to the Consolidated Financial Statements
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Cash equivalents
Cash equivalents are short-term, highly-liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortised cost.

Loans granted
Loans granted that have fixed or determinable payments that are not quoted in an active market are classified as financial assets at amortised cost and are measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate.

Loans granted to related parties are normally interest-free and do not have a fixed repayment structure. These loans are classified as financial assets at amortised cost and are measured at amortised cost using the effective interest method, less any impairment. Effective interest rate being zero in this case.

Derecognition
A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is primarily derecognised (i.e., removed from the Group's consolidated statement of financial position) when:

The rights to receive cash flows from the asset have expired or the Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Group has transferred substantially all the risks and rewards of the asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

When the Group has transferred its rights to receive cash flows from an asset or has entered into a pass-through arrangement, it evaluates if, and to what extent, it has retained the risks and rewards of ownership. When it has neither transferred nor retained substantially all of the risks and rewards of the asset, nor transferred control of the asset, the Group continues to recognise the transferred asset to the extent of its continuing involvement. In that case, the Group also recognises an associated liability. The transferred asset and the associated liability are measured on a basis that reflects the rights and obligations that the Group has retained.

Impairment of financial assets
The Group recognises an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms.

ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Group applies a simplified approach in calculating ECLs. Therefore, the Group does not track changes in credit risk, but instead recognises a loss allowance based on lifetime ECLs at each reporting date. The Group has established a provision matrix that is based on its historical credit-loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

The Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Group may also consider a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

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ii Financial liabilities

Initial recognition and measurement
Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, financial liabilities at amortised cost, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate.

All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables, loans and borrowings including bank overdrafts, and derivative financial instruments.

Subsequent measurement
For purposes of subsequent measurement, financial liabilities are classified in two categories:
- Financial liabilities at fair value through profit or loss
- Financial liabilities at amortised cost

Financial liabilities at fair value through profit or loss
Financial liabilities at fair value through profit or loss include financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Group that are not designated as hedging instruments in hedge relationships as defined by AASB 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognised in the statement of profit or loss.

Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in AASB 9 are satisfied. The Group has not designated any financial liability as at fair value through profit or loss.

Financial liabilities at amortised cost
This is the category most relevant to the Group. After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the EIR method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in the statement of profit or loss.

This category generally applies to interest-bearing loans and borrowings. For more information, refer to Note 19.

Foreign exchange gains and losses
For financial liabilities that are denominated in a foreign currency and are measured at amortised cost at the end of each reporting period, the foreign exchange gains and losses are determined based on the amortised cost of the instruments. These foreign exchange gains and losses are recognised in the 'foreign exchange gain / (loss)' line item in profit or loss for financial liabilities that are not part of a designated hedging relationship. For those which are designated as a hedging instrument for a hedge of foreign currency risk foreign exchange gains and losses are recognised in other comprehensive income and accumulated in a separate component of equity.

The fair value of financial liabilities denominated in a foreign currency is determined in that foreign currency and translated at the spot rate at the end of the reporting period. For financial liabilities that are measured as at FVTPL, the foreign exchange component forms part of the fair value gains or losses and is recognised in profit or loss for financial liabilities that are not part of a designated hedging relationship.

Derecognition of financial liabilities
The Group derecognises financial liabilities when, and only when, the Group's obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognised and the consideration paid and payable is recognised in profit or loss.

When the Group exchanges with the existing lender one debt instrument into another one with the substantially different terms, such exchange is accounted for as an extinguishment of the original financial liability and the recognition of a new financial liability. Similarly, the Group accounts for substantial modification of terms of an existing liability or part of it as an extinguishment of the original financial liability and the recognition of a new liability. It is assumed that the terms are substantially different if the discounted present value of the cash flows under the new terms, including any fees paid net of any fees received and discounted using the original effective rate is at least 10 per cent different from the discounted present value of the remaining cash flows of the original financial liability. If the modification is not substantial, the difference between: (1) the carrying amount of the liability before the modification; and (2) the present value of the cash flows after modification is recognised in profit or loss as the modification gain or loss within other gains and losses.

Notes to the Consolidated Financial Statements
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iii. Fair value measurement
The Group measures derivatives at fair value at each balance sheet date and, for the purposes of impairment testing, uses fair value less costs to sell (FVLCD) to determine the recoverable amount of some of its non-financial assets.
Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on the presumption that the transaction to sell the asset or transfer the liability takes place either:
- In the principal market for the asset or liability

Or
- In the absence of a principal market, in the most advantageous market for the asset or liability

The principal or the most advantageous market must be accessible by the Group.

The fair value of an asset or a liability is measured using the assumptions that market participants would use when pricing the asset or liability, assuming that market participants act in their economic best interest.

A fair value measurement of a non-financial asset takes into account a market participant's ability to generate economic benefits by using the asset in its highest and best use or by selling it to another market participant that would use the asset in its highest and best use.

The Group uses valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, maximising the use of relevant observable inputs and minimising the use of unobservable inputs.

All assets and liabilities, for which fair value is measured or disclosed in the financial statements, are categorised within the fair value hierarchy, described as follows, based on the lowest-level input that is significant to the fair value measurement as a whole:
Level 1 – Quoted (unadjusted) market prices in active markets for identical assets or liabilities
Level 2 – Valuation techniques for which the lowest-level input that is significant to the fair value measurement is directly or indirectly observable
Level 3 – Valuation techniques for which the lowest-level input that is significant to the fair value measurement is unobservable

iv. Offsetting of financial instruments
Financial assets and financial liabilities are offset, and the net amount is reported in the consolidated statement of financial position if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis, to realise the assets and settle the liabilities simultaneously.

Notes to the Consolidated Financial Statements
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30u. Joint arrangements
Joint arrangements are arrangements of which two or more parties have joint control. Joint control is the contractual agreed sharing of control of the arrangement which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control. Joint arrangements are classified as either a joint operation or joint venture, based on the rights and obligations arising from the contractual obligations between the parties to the arrangement.

To the extent the joint arrangement provides the Company with rights to the individual assets and obligations arising from the joint arrangement, the arrangement is classified as a joint operation and as such, the Company recognises its:
- Assets, including its share of any assets held jointly;
- Liabilities, including its share of any liabilities incurred jointly;
- Revenue from the sale of its share of the output arising from the joint operation;
- Share of revenue from the sale of the output by the joint operation; and
- Expenses, including its share of any expenses incurred jointly.

To the extent the joint arrangement provides the Company with rights to the net assets of the arrangement, the investment is classified as a joint venture and accounted for using the equity method. Under the equity method, the cost of the investment is adjusted by the post-acquisition changes in the Company's share of the net assets of the venture.

30v Current versus non-current classification
The Group presents assets and liabilities in the statement of financial position based on current/non-current classification. An asset is current when it is either:
- Expected to be realised or intended to be sold or consumed in the normal operating cycle;
- Held primarily for the purpose of trading;
- Expected to be realised within 12 months after the reporting period;
- Cash or cash equivalent unless restricted from being exchanged or used to settle a liability for at least 12 months after the reporting period.

All other assets are classified as non-current.

A liability is current when either:
- It is expected to be settled in the normal operating cycle
- It is held primarily for the purpose of trading
- It is due to be settled within 12 months after the reporting period
- There is no unconditional right to defer the settlement of the liability for at least 12 months after the reporting period

The Group classifies all other liabilities as non-current.

Deferred tax assets and liabilities are classified as non-current assets and liabilities.

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30w Business combinations and goodwill
In order to consider an acquisition as a business combination, the acquired asset or groups of assets must constitute a business (an integrated set of operations and assets conducted and managed for the purpose of providing a return to the investors). The combination consists of inputs and processes applied to these inputs that have the ability to create output. Acquired businesses are included in the financial statements from the transaction date. The transaction date is defined as the date on which the company achieves control over the financial and operating assets. This date may differ from the actual date on which the assets are transferred. Comparative figures are not adjusted for acquired, sold or liquidated businesses. On acquisition of a licence that involves the right to explore for and produce petroleum resources, it is considered in each case whether the acquisition should be treated as a business combination or an asset purchase. Generally, purchases of licences in a development or production phase will be regarded as a business combination. Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest (NCI) in the acquiree. For each business combination, the Group elects whether to measure NCI in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition related costs are expensed as incurred and included in administrative expenses.

When the Group acquires a business, it assesses the assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree. Those acquired petroleum reserves and resources that can be reliably measured are recognised separately in the assessment of fair values on acquisition. Other potential reserves, resources and rights, for which fair values cannot be reliably measured, are not recognised separately, but instead are subsumed in goodwill.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Contingent consideration classified as an asset or liability that is a financial instrument and within the scope of AASB 9 Financial Instruments: Recognition and Measurement is measured at fair value, with changes in fair value recognised either in the statement of profit or loss or as a change to other comprehensive income. If the contingent consideration is not within the scope of AASB 9, it is measured in accordance with the appropriate AASB. Contingent consideration that is classified as equity is not remeasured, and subsequent settlement is accounted for within equity.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for NCI over the fair value of the identifiable net assets acquired and liabilities assumed. If the fair value of the identifiable net assets acquired is in excess of the aggregate consideration transferred (bargain purchase), before recognising a gain, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognised in the statement of profit or loss and other comprehensive income.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash generating units (CGUs) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a CGU and part of the operation in that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal.

Goodwill disposed of in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

Directors' Declaration and Statement of Responsibility

We confirm that in the opinion of the Directors:

a. the financial statements and notes of PetroNor E&P Limited for the year ended 31 December 2020 are in accordance with the Corporations Act 2001, including:
   i. giving a true and fair view of its financial position as at 31 December 2020 and of its performance for the year ended on that date; and
   ii. complying with Australian Accounting Standards (including the Australian Accounting Interpretations) and the Corporations Regulations 2001; and
   iii. complying with International Financial Reporting Standards as disclosed in Note 2.

b. there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

c. that the Directors' Report together with the Unaudited Additional Information includes a fair review of the development and performance of the business and the position of PetroNor E&P Limited and the Group taken as a whole, together with a description of the principal risks and uncertainties that they face; and

d. to the best of our knowledge, the country-by-country report for 2020 has been prepared in accordance with the Norwegian Security Trading Act Section 5-5a."

The Directors have been given the declarations required by Section 295A of the Corporations Act 2001 from the Chief Executive Officer, Knut Søvold, and the Group Financial Controller, Chris Butler, for the year ended 31 December 2020.

29 April 2021
The Board of Directors
PetroNor E&P Ltd

Eyas Alhomouz
Chairman of the Board

Gro Kielland
Director of the Board

Joseph Iskander
Director of the Board

Roger Steinepreis
Director of the Board

Jens Pace
Director of the Board

Alexander Neuling
Director of the Board

Ingvil Smines Tybring-Gjedde
Director of the Board

Independent Auditors' Report

To the members of PetroNor E&P Limited
Report on the Audit of the Financial Report

Opinion
We have audited the financial report of Entity Name (the Company) and its subsidiaries (the Group), which comprises the consolidated statement of financial position as at 31 December 2020 , the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, and notes to the financial report, including a summary of significant accounting policies and the directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the Corporations Act 2001, including:
(i) Giving a true and fair view of the Group's financial position as at 31 December 2020 and of its financial performance for the year ended on that date; and
(ii) Complying with Australian Accounting Standards and the Corporations Regulations 2001.

Basis for opinion
We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the Financial Report section of our report. We are independent of the Group in accordance with the Corporations Act 2001 and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 Code of Ethics for Professional Accountants (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the Corporations Act 2001, which has been given to the directors of the Company, would be in the same terms if given to the directors as at the time of this auditor's report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion

Key audit matters
Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report of the current period. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Carrying value of Production assets and equipment

Key audit matter	How the matter was addressed in our audit
Refer to Note 15 of the financial statements, for disclosure over the Carrying value of Production assets and Equipment. The carrying value of Production assets and Equipment is impacted by various key estimates and judgements in particular: • Reserves estimates; • Amortisation rates; • Capitalisation and attribution of production costs; and • Life of production asset. The Group is also required to assess for indicators of impairment at each reporting period. The assessment of impairment indicators in relation to the Production assets and Equipment requires management to make significant accounting judgements and estimates which includes discount rates, commodity price and reserve estimates. This is a key audit matter due to the quantum of the asset and the significant judgement involved in management's assessment of the carrying value of Production assets and Equipment.	Our work with the assistance of our component auditors included, but was not limited, to the following procedures: • Reviewing management's amortisation models, including agreeing key inputs tosupporting information; • Assessing the competency and objectivity of, and work performed by, management's experts in respect of the reserve estimates; • Assessing management's judgements over capitalisation of additions to production assets and equipment; – Evaluating and challenging management's assessment of indicators of impairment under the International Accounting Standards for the Production assets and Equipment by: – Comparing the carrying amount of the Group's net assets against the market capitalisation, both as at 31 December 2020, and subsequent movements; – Considering commodity price assumptions at 31 December 2020, including forecasts; – Comparing the carrying value to the independent reserves and valuation reports; – Reviewing board and sub-committee meeting minutes, and holding discussions with key management, including non-finance personnel; and – Assessing economic indicators for impacts on appropriate discount rates; and • We also assessed the adequacy of related disclosures in Note 15 to the financial statements.

Independent Auditors' Report
Continued

Other information
The directors are responsible for the other information. The other information comprises the information in the Group's annual report for the year ended 31 December 2020, but does not include the financial report and the auditor's report thereon.

Our opinion on the financial report does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the directors for the Financial Report
The directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the Corporations Act 2001 and for such internal control as the directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the directors are responsible for assessing the ability of the group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the directors either intend to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the Financial Report
Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website at: http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf

This description forms part of our auditor's report

BDO Audit (WA) Pty Ltd
Phillip Murdoch
Director
Perth
29 April 2021

Glossary of terms

Bbl	One barrel of oil, equal to 42 US gallons or 159 liters
Bcf	Billion cubic feet
bopd	Barrels of oil per day
boepd	Barrels of oil equivalent per day
CPP	Production sharing contract, “Contrat de Partage de Production” in French
CPR	Competent Person’s Report
Group or PetroNor Group	PetroNor E&P Limited and its subsidiaries
IOR	Improved oil recovery
MMbbl	Million barrels of oil
MMBOE	Million barrels of oil equivalent
Mmscfd	Million standard cubic feet per day
PDP	Proven Developed Producing (reserves)
PSC	Production sharing contract
SNPC	Société National des Pétroles du Congo

Corporate Directory

Directors
Eyas Alhomouz, Chairman
Joseph Iskander
Gro Kielland
Alexander Neuling
Jens Pace
Roger Steinepreis
Ingvil Smines Tybring-Gjedde

Company Secretary
Angeline Hicks

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T +47 22 55 46 07

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Al Khalidiya
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United Arab Emirates
P.O.Box 35491

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Egkomi,
2409 Nicosia,
Cyprus

Stock Exchange Listing
Oslo Euronext Expand
Code: PNOR

Share Registrar
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Level 11, 172 St George’s Terrace
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Auditors
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Australia
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APPENDIX D:

AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED 31 DECEMBER 2019

PETRONOR E&P

PROGRESSING OPPORTUNITIES

Annual Report 2019

SUSTAINABLE RESOURCE DEVELOPMENT

PetroNor E&P, listed on the Oslo Axess (PNOR), is an independent oil and gas company led by an experienced board and management team, with substantial experience in oil and gas exploration, appraisal, development and production.

PetroNor E&P listed on Oslo Axess 12 September 2019

Contents

Highlights

2019 highlights and subsequent events

- Following our entry in 2017 into a producing asset in West Africa, 2019 has been a year to cement our success and focus on further expansion through the merger between the former African Petroleum Corporation Ltd and PetroNor, and to increase activity in West Africa, primarily in Nigeria.
- Since our acquisition of the interest in the PNGF Sud licence, the licence has seen both production increase and a reduction in operating cost.
- Restructuring of the combined group to streamline the organisation to reduce overhead costs and grow technical excellency.
- Focus on bringing a solution to the Gambia and Senegal arbitration processes as well as expanding to Nigeria.

Assets

Republic of Congo (Brazzaville)

- 10.5% indirect participation interest in the licence group of PNGF Sud (Tchibouela II, Tchendo II and Tchibeli-Litanzi II) through Hemla E&P Congo SA.
- The Group holds the right to negotiate, in good faith, the terms of the adjacent licence of PNGF Bis and a 14.7% indirect participation.

Nigeria

- Signed a transaction with Panoro Energy to acquire their 6.052% nominal shareholding in the Aje Field and to establish a joint venture with Yinka Folawiyo Petroleum ("YFP") which will give PetroNor a 13.1% economic interest in the asset.

Senegal and The Gambia

- Though currently in arbitration, the Company reserves its rights in the exploration blocks Rufisque Offshore Profond and Senegal Offshore Sud Profond in Senegal and A1 & A4 in The Gambia.

EBITDA (USD)
49.00m
-7.7% (2018: 53.10m)

EBIT (USD)
45.77m
-8.3% (2018: 49.89m)

Net profit/(loss) (USD)
(5.76)m
(2018: 17.06m)

10.8 MMbbl
2P Reserves
(2018: 8.5MMbbl)

7.3 MMbbl
2C Contingent Resources
(2018: 7.6MMbbl)

4.9 bnbbl
net unrisked prospective resources[1]

~2,640 bbl/d
net oil production[2]

1. ERC Equipoise, assets in dispute.
2. Includes 314 bbl/d from OML 113 interest which is subject to contract completion.

OUR DIVERSIFIED PORTFOLIO

Our mission

Our mission is to generate shareholder value by leveraging the technical and commercial skillset of the Company to enhance its reserve base, production and cash flow. PetroNor E&P is committed to the highest standards of corporate governance, transparent stakeholder engagement and operational excellence.

Our strategic vision is to steadily build the company into a fullcycle, Africa-focused exploration and production company with an emphasis on producing and developing assets with upside potential. To reflect growth ambitions, the Board has set a target of achieving reserves of 300 mmboe and production of 30,000 barrels of oil equivalent per day (boepd) in the next three years.

What we do

We are an independent oil and gas exploration and production company with licences in four countries offshore; West Africa-Republic of Congo, Senegal, The Gambia and Nigeria. The Company has amassed a diverse and high-quality portfolio comprising economically-robust production, development upside, and high-impact exploration.

CONGO-B

Congo Brazzaville is a core country for PetroNor, both for production as well as for regional expansion.

PNGF Sud is operated by Perenco – a world leading company with +400,000 bbl/d. Perenco has specialized in low-cost tail production assets like PNGF Sud.

Production in PNGF Sud has increased 50% since its takeover, combined with significant cost improvements.

Several mature assets are coming to the market over the new few years, giving a significant growth opportunity for PetroNor.

Production (net)

2,327 bbl/d

2P Resources (net)

10.8 MMbbl

2C Resources (net)

7.3 MMbbl

4 fields: 10.5% Indirect Interest

Offices

The Company has its registered address in Perth, Australia. The Group maintains headquarters in London, and operational offices in Oslo, Nicosia and Abu Dhabi.

NIGERIA

Nigeria is a core country for PetroNor due to its significant number of undeveloped assets.

PetroNor has created a joint venture together with the operator' YFP for the revitalisation of the Aje field.

Current oil and condensate production at the Aje field to be increased up to 8,000 bbl/d with the liquids only, and 20,000 boepd including the gas development.

PetroNor is seeing a significant number of opportunities for merger and acquisition (M&A) in Nigeria.

Production (net)

314 bbl/d

2C Resources (net)

18.7 MMbbl

1 field: 13.08% Initial Economic Interest

SENEGAL

Senegal has an exciting exploration potential that includes the discovery of the world-class Sangomar field adjacent to the licensed ROP block.

Net unrisked Prospective Resources

1,779 MMbbl

2 licences: 14,216km² (net) 90% working interest

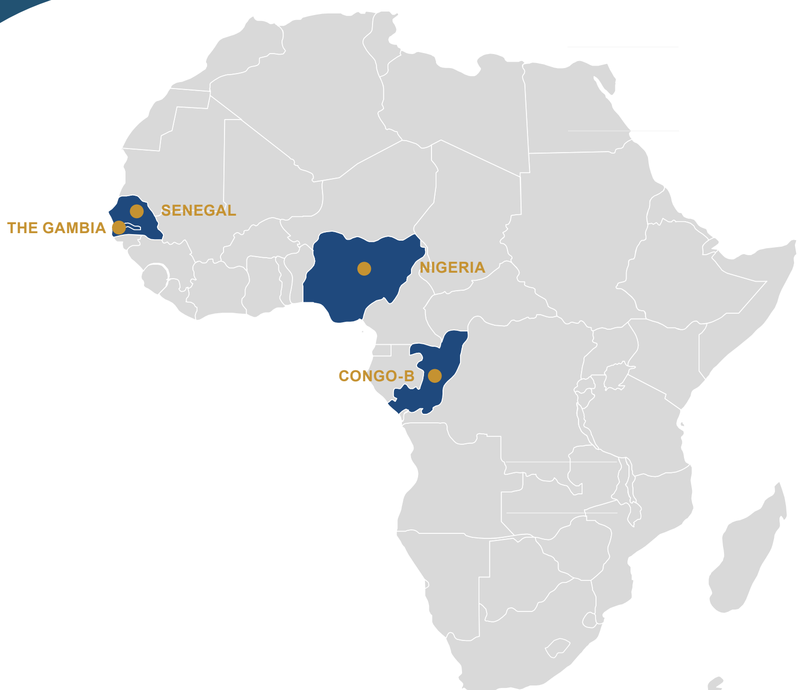
THE GAMBIA

The Gambia is within the same proven play trend as Senegal and the Sangomar field, a play which is expected to extend southward into The Gambia.

Net unrisked Prospective Resources

3,079 MMbbl

2 licences: 2,672km² (net) 100% working interest



Business development
Focusing on opportunities onshore and offshore sub-Saharan Africa

CONGO-BRAZZAVILLE

The Republic of Congo (Congo-Brazzaville) is the third-largest oil producer in sub-Saharan Africa, after Nigeria and Angola, with an output of around 350,000 bbl/d. The majority of the production in Congo is located offshore, with approximately half in deep water.

Operational gross production

21,920 bbl/d

(2018: 20,326 bbl/d)

2P Reserves and resources (net)

10.8 MMbbl

(2018: 8.6 MMbbl)

2C Reserves and resources (net)

7.3 MMbbl

(2018: 7.6 MMbbl)

PNGF Sud

Licence overview

In 2016 production rates were less than 15,000 bbl/d when Total exited and the current partnership took over the licence with Perenco as operator. Since then, low-cost brick by brick improvements via workovers and production process improvements have resulted in today's production levels of circa 23,000 bbl/d.

Net interest

10.5%

Reserves growth through infill drilling 2020-2021 (Litanzi and Tchendo)

Litanzi:
- Jackup acquired and modified with simple processing – oil and water to Tchendo
- Two infill producers and two infill injectors targeting upswept fault terraces
- Estimated improved recovery of 8-12 MMbbl
- Total expected CAPEX of USD 100 million gross (USD 10.5 million net)
- Economics attractive for reserve additions with between 8-13 USD/bbl of CAPEX

Tchendo:
- Wellhead platform with platform or tender rig installed, allowing for expansion of the infill programme
- Initially six infill producers are planned at Tchendo at c. USD 5 million/well
- Total expected CAPEX USD 84 million gross with incremental recovery of 5-6 MMbbl corresponding to 12-17 USD/bbl

PNGF Bis

Licence overview

PNGF Bis is located next to PNGF Sud and contains two discoveries from 1985-1991 (Loussima SW and Loussima). The partnership has a right to negotiate the licence on given terms with possible conclusion in 2020. The three discovery wells tested from 1,150 to 4,700 bbl/d of light, good quality oil. Perenco has recently made a detailed reinterpretation, 3D modelling and facilities study for the Loussima SW discovery, yielding >100 MMbbl of in-place resources and a possible lie-back to Tchibouela.

AGR Petroleum Services warrants 2C resources of 29 MMbbl in a 2019 CPR including verification of the tie-back scenario given above.

Net interest

14.7%

Licence activity

- Low Cost Production – Lifting Cost (OPEX) 12.5 USD/bbl
- Net production of 2,301 bbl/d (2019 average)
- Tchibouela East production restarted in 2019; further growth expected
- New high-quality 3D reservoir models now being utilised for field management
- Infill drilling programmes at Litanzi and Tchendo will target further production increases
- Cost-effective (<2 USD/bbl) workover programme to enhance production
- Investment in surface equipment to improve processes and support growth
- Rerouted Tchibeli production to reduce third party processing tariffs
- Significant further enhancement potential (currently 23% recovery only)

Producing wells

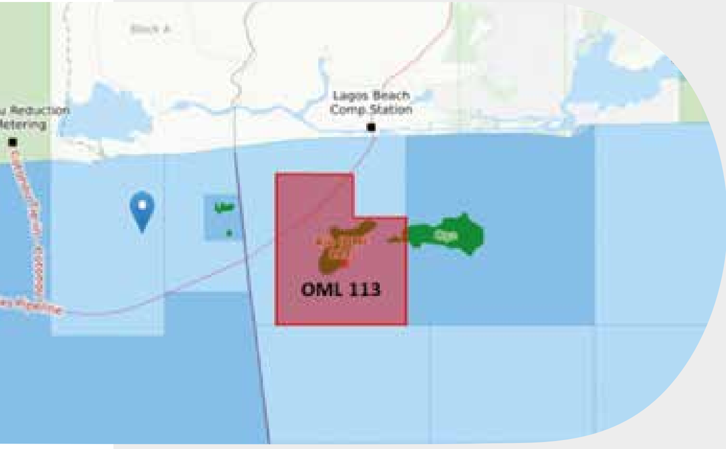
61

Licence activity

- Proven reserves in Loussima SW to be appraised and developed in a phased approach to manage uncertainty
- Early production scheme planned, prior to decision to proceed with full development
- Development plan is to use low-cost jack-up with minimum topside upgrading and 11km catenary pipeline to Tchibouela
- Significant potential upside from Loussima discovery of 46° API oil to be appraised

NIGERIA

Nigeria is one of the most petroleum-rich nations in the world. Nearly all of the country's primary reserves are concentrated in and around the Niger Delta. Nigeria is one of the few major oil-producing nations still capable of increasing its oil output.



Estimated gross production for 2020

2,300 bbl/d

(2018: 2,967 bbl/d)

2C Resources (net)

18.7 MMbbl (17.4%)

Nominal interest: 34.0%
Economic interest: 13.1%
Economic interest new development: 17.4%

OML 113 (Aje Field)

Licence overview

The Aje Field was discovered after drilling of the Aje-1 well in 1996. The OML 113 block covers 835km² with water depths ranging from 100m to 1,500m. Five wells have been drilled; oil production is from Turonian and Cenomanian age reservoirs. PetroNor acquired the Panoro equity share in the field in 2019. An SPV has been setup with the operator YFP whereby PetroNor have joint technical operatorship (subject to final approval by the Nigerian government). Overlying the Turonian oil rim is a significant gas-condensate discovery which has not been developed. Gas produced from the field is flared.

Forward plan

The Nigerian government encourages stop-flaring programmes and the country is in dire need of electrical power. Through the entry to Aje as joint operator, PetroNor will target the gas, condensate and oil in a low-risk development plan. Wet-gas will be brought to shore for further processing and extraction of LPG.

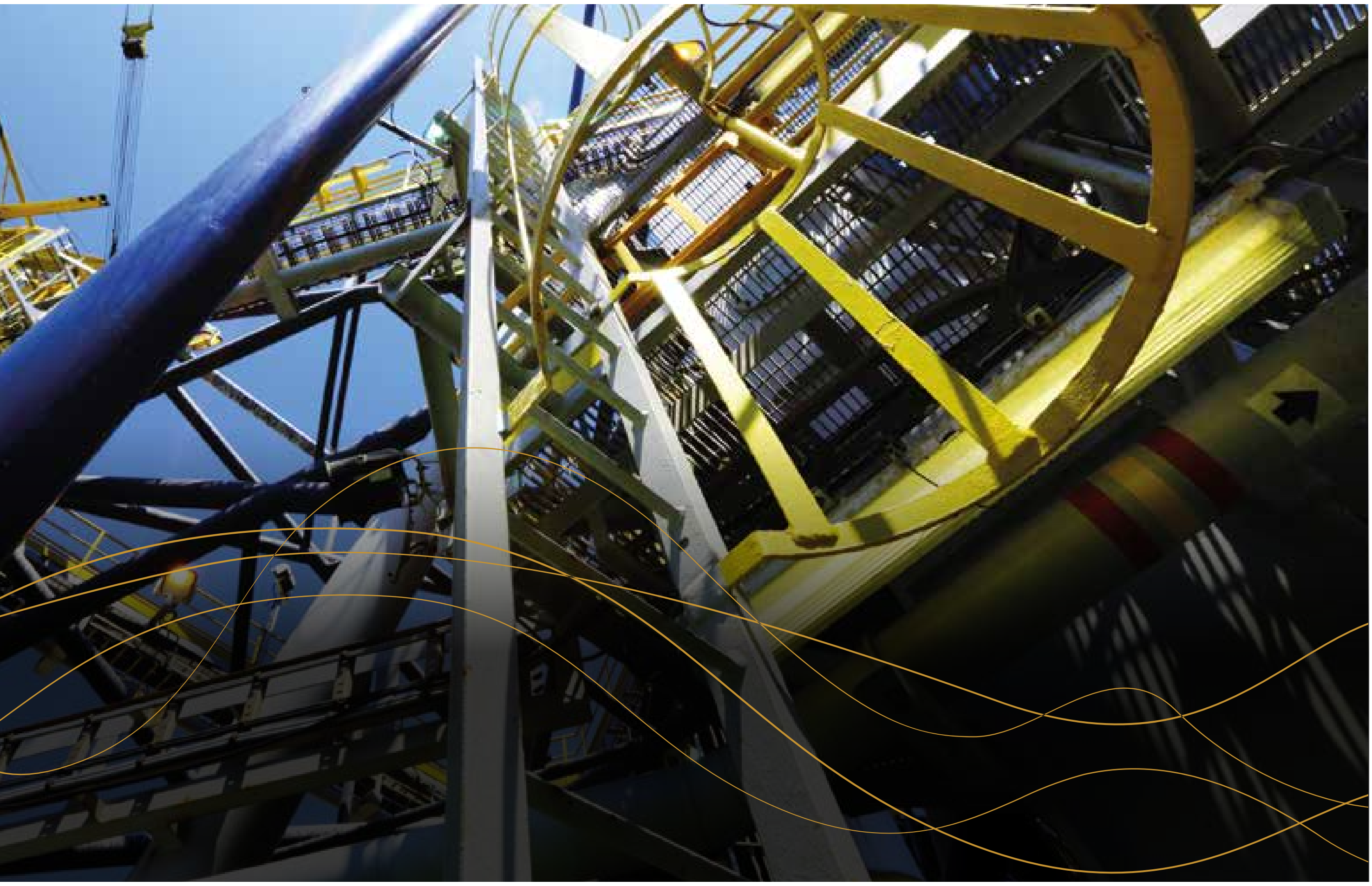
Net interest

13.1%

Licence Activity

The current partnership has invested significantly into the current drilling and development. With the current (low) production, the only sustainable future is to invest to target the already-discovered oil and gas volumes in Aje. With different partnership economics, the partners have struggled to agree on a suitable way forward. PetroNor offers a robust development solution to the partnership.

- The flared gas will be reinjected to stop the resource waste and allow for a gas recycling process
- Condensate will be stripped from the gas produced offshore and “dry” gas will be reinjected until gas commercialisation is available
- While drilling gas well locations, additional oil targets will be appraised
- Gas commercialisation options include direct sales of rich gas or further processing in a purpose-built gas plant to extract additional liquids (LPG and condensate) before the gas is sold to the local market.



SENEGAL & THE GAMBIA

The Company reserves its rights to 90% operating working interest in the exploration blocks Rufisque Offshore Profond ("ROP") and Senegal Offshore Sud Profond ("SOSP") comprising 14,216 km².

Net unrisked prospective resources

1,779 MMbbl

Senegal

Licence overview

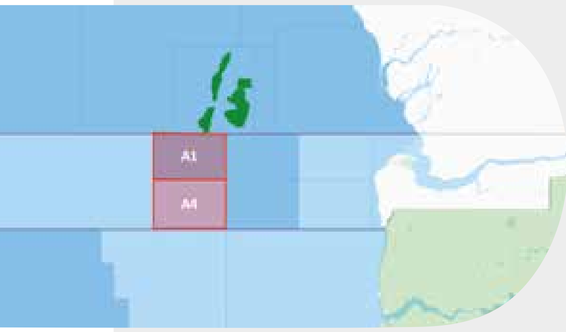
The award of the ROP licence to Total in February 2017 is the subject of ongoing international arbitration. PetroNor reserves its rights to 90% equity in the ROP block. Petronas farmed-in in August 2018 and Total (60% Operator), Petronas (30%) and Petrosen (10%) drilled the Jamm-1X well in August 2019 (after acquisition, and processing of a large 3D seismic survey). Jamm-1X was classed as a non-commercial oil discovery (successfully extending the oil trend northward and further basinward).

In May 2020, the Company reached an agreement with the Government of Senegal to suspend the arbitration related to the Rufisque Offshore Profond and Senegal Offshore Sud Profond licence areas for a period of six months, with a view to reaching a satisfactory outcome for all parties. A formal request was lodged with the International Centre for Settlement of Investment Disputes (ICSID) to suspend the process.

Net interest

90%

The Company reserves its rights to the 100% operating working interest in the offshore licenses A1 and A4, comprising 2,672 km².



Net unrisked prospective resources

3,079 MMbbl

The Gambia

Licence overview

The award of Block A1 to BP in April 2019, is disputed by PetroNor and is the subject of ongoing international arbitration. PetroNor continues to reserve its rights in relation to both the A1 and A4 licenses and will continue with its efforts to protect its interest through the ongoing arbitration process.

BP plans to conduct an environmental assessment followed by a two-year drilling period in Block A1. The adjacent A2/A5 acreage is operated by Far Ltd (50%), in partnership with Petronas (50%). The Samo-1 well was drilled in late 2018; though a dry hole, it had encouraging shows at multiple levels. Increased interest from large International Companies and ongoing work commitments verify the high potential of this acreage. PetroNor looks forward to the resolution of the ongoing arbitration.

Net interest

100%

CLEAR STRATEGIC VISION

Eyas Alhomouz | Chairman

I am delighted to provide my first annual statement to PetroNor E&P's shareholders and our wider stakeholders. Last year was a year of transformation and inception, as PetroNor E&P was formed through the combination of African Petroleum and PetroNor in an all-share transaction.

"NEW BUSINESS DEVELOPMENT WILL BE AT THE HEART OF OUR STRATEGIC EXECUTION, AS WE SEEK ASSETS THAT DIVERSIFY OUR PORTFOLIO."

The combination has a strategic vision to develop into a material full-cycle oil and gas company. The rationale for the combination was clear for both parties and the Company today is well-positioned to leverage its existing platform to achieve scale, deliver sustainable value and establish itself as a leading independent E&P focused on Africa.

The enlarged group is underpinned by cash flow from an economically-robust asset base in Congo, and has the financial stability, and enhanced profile and network, to better-pursue satisfactory outcomes from the ongoing arbitration processes related to the licences in Senegal and The Gambia. It has also created a Board and management team with a diverse skillset comprising technical, commercial and financial expertise, with a proven track record for value creation and M&A execution. Leveraging the deep technical expertise of the management team to identify and exploit value-realisation opportunities from undeveloped or underperforming assets remains a core aspect of the growth strategy and, we believe, a critical element of PetroNor E&P's investment case.

The high-quality, low-risk and long-life asset base in Congo-Brazzaville continues to perform strongly, and provides the Company with robust cash flow from net working interest production of 2,301 bbl/d (average for the year). The asset has robust economics, remaining cash-flow positive down to USD 20 Brent, meaning it remains sustainable in the current low oil-price environment. Alongside our partners, the joint venture continues the optimisation of the field, both through low-cost intervention programmes as well as a new drilling programme. PNGF Sud, with its ~2bn bbl stock tank original oil-in-place (STOOIP) and a current average recovery factor of ~23%, still has significant potential for increased oil recovery.

In November, the Company announced a significant increase in 2P Reserves from PNGF Sud. An independent evaluation by AGR Petroleum Services AS ("AGR") of the producing fields confirmed the remaining net 2P oil reserves net to PetroNor (corrected for actual 2019 production to 1.1.2020) to be 10.76 MMbbl, representing a 26% increase compared to the previous year. This independent evaluation confirms the quality of the asset and the, as yet unrealised, core value associated with PetroNor E&P's indirect interest in the assets.

Following the formal completion of the merger in late August, the Company has proactively sought to engage with the relevant authorities in Senegal and The Gambia with a view to finding middle ground that is beneficial to all parties and avoids a prolonged and costly legal process through to completion. The situation regarding these licences remains complex and the outcome remains uncertain. Suffice to say, the Board is fully focused on achieving an outcome that is in the best interest of the Company's shareholders and this is front and centre of all decision-making associated with these assets.

Our strategic vision is clear; to steadily build the company into a full-cycle, Africa-centric E&P focusing on producing assets with upside and development of stranded assets. New business development will be at the heart of our strategic execution, as we seek assets that diversify our portfolio, and provide us with an opportunity to leverage our deep technical and commercial expertise to realise maximum value from assets.

In this regard, we were pleased to have announced a compelling first transaction rapidly after completing the merger. The acquisition of Panoro Energy's interest in OML 113, offshore Nigeria, is consistent with our strategy and provides us with additional cash flow, but more importantly an opportunity to unlock the true potential of this asset through partner alignment and technical execution. Nigeria is a country with an abundance of opportunities and a jurisdiction in which PetroNor E&P has extensive experience and network, and we continue to screen multiple opportunities in the country. Having subsequently signed an investment and shareholders' agreement with the OML 113 Operator, Yinka Folawiyo Petroleum ("YFP"), we now await final approvals from the relevant authorities, after which we will commence work with our partners as we seek to revitalise and further develop OML 113 and the Aje oil and gas field.

As an established and growing E&P, sustainability is a key consideration, both in terms of our business and our operating footprint. Global climate change has, quite rightly, become a more prominent theme for the industry, and investors are increasingly conscious of the ethical impact of their investments. As such, Environmental, Social and Governance ("ESG") has become a highly-relevant topic and our management and Board are undertaking a review of their activities in each of these categories to ensure the Company is operating at the highest industry standards and meeting shareholder expectations in this regard.

Following completion of the merger, the Board has undertaken a review to ensure the corporate structure is fit for purpose. Cost discipline is a fundamental driver for our business, and we have subsequently considered all areas where we can deliver cost savings without impacting the effectiveness of the business. We have successfully reduced overheads by reducing the size of the Board and management team; and will seek to deliver further cost savings this year through corporate initiatives, including a reduction in salaries and expenses, and a likely domiciliation to Europe. I would like to thank all the Directors who have left the Company in recent months, and extend particular thanks to both Jens Pace and Steve West who relinquished their roles as CEO and CFO respectively post period. The current structure of the Board and management team is better-suited for a company of our size, and we retain a deep and diverse skillset that will enable us to deliver on our strategic objectives.

Through the first quarter of 2020, the market conditions for the sector deteriorated rapidly due to a combination of global market-share disputes and the worrying impact of Coronavirus on international demand for hydrocarbons. The result has been a drastic decline in commodity pricing that has sent shockwaves through the industry and created uncertainty over CAPEX budgets and project-viability. In these times of uncertainty, it's more important than ever for companies to show financial discipline at all levels of the business. The Board will continue to drive down overheads and work with JV partners at the producing assets in Congo to ensure the sustainable economic robustness of the assets in a lower-for-longer price environment. Furthermore, the Company remains well-placed to consider business development opportunities created as a result of this unfortunate market dynamic, and we continue to aggressively screen compelling opportunities at attractive valuations, in line with our stated growth strategy.

This year represents a critical juncture for the Company as we seek to build on the momentum generated following the merger. We are wholly focused on delivering the objectives that are under our control, namely operational progress in Congo, and in Nigeria (when that deal completes), as well as further new business development in line with our strategy.

The Company is confident that it has the right assets, people and strategy to achieve its ultimate objectives of becoming a leading, independent E&P, focused on Africa. While the near-term outlook is both uncertain and challenging for the entire industry, we believe in the long-term demand for hydrocarbons across the African continent, and believe we are particularly well-placed to capitalise on opportunities that will deliver long-term, sustainable value for our shareholders.

Finally, I'd like to thank the PetroNor E&P team for their tireless work and extend thanks to our wider stakeholders, including partners and host governments. We are excited about the future and look forward to reporting on our progress throughout the year.

Yours Sincerely,

Eyas Alhomouz
Chairman

POSITIONED FOR GROWTH

Knut Søvold | Chief Executive Officer

We believe that we have all the elements required, in terms of management, expertise, strategy, network, assets, and supportive shareholders, to realise our long-term ambitions, and are subsequently uniquely-placed to capitalise on the challenging market dynamics and to benefit from any opportunities that may arise.

"PETRONOR WAS FORMED ON THE BASIS OF CREATING LOCAL GROWTH AND SUSTAINABLE OPERATIONS."

PetroNor Timeline

2020 onward

Develop PNGF Sud, initially through 2020 - 2021 infill drilling programme

Finalise PNGF Bis contract and commence drilling

Rejuvenate OML 113 partnership and Aje development plan

Resolve Senegal and The Gambia disputes

Grow PetroNor into a leading E&P independent through M&A

Target 30,000 boepd net production by 2023

2019

Completed business combination with African Petroleum Corporation and relisted as PetroNor on Oslo Axess

PNGF Sud reaches production of 22,000 bbl/d, up >7,000 bbl/d (~50%) since licence-acquisition

Litanzi infill drilling programme approved

Announced Aje transaction with Panoro – low-cost entry into producing asset with significant unlocked potential. Strengthens the PetroNor shareholder base through share consideration

2017

Entered 2017 with PNGF Sud gross production of circa 15,000 bbl/d

Together with new operator, Perenco, initiated significant operational efforts to reduce costs and increase production

2016

NOR Energy and Petromal joined forces

PetroNor established

Acquired PNGF Sud interest in Congo following Total's exit

Q&A

Q: What's the long-term vison?

A: We want to establish PetroNor E&P as a leading, full-cycle African oil and gas company. We recognise the importance of achieving scale to ensure relevance and open up exciting opportunities, and have set ourselves a target of producing 30,000 boepd net in the next few years, through organic and inorganic growth. Clearly this target is ambitious, and based on market conditions and ability to fund and execute sizeable transactions, however it reflects the scale of our near-term ambitions. The current challenges in the oil market also open opportunities for commercially-robust transactions. We are confident that we have the right people, assets and supportive major shareholders to achieve this vision.

Q: How is the production at PNGF Sud doing?

A: The PNGF Sud has been a great success, with growth from c.15,000 bbl/d to a current production level of c.23,000 bbl/d. This solid production growth of >50% has been achieved through maintenance and simple workovers at a cost of some 2 USD/bbl and shows the proficiency of Perenco as a brown-field operator. In addition to the already identified 2C opportunities, the asset has a significant ~2bn bbl of Stooip and an average recovery factor of 23%, indicating that there is still potential for continued production growth through infill drilling in the years to come.

Q: How will the Company meet the current crisis in the oil industry related to the drop in oil price?

A: In light of the challenging environment the industry is currently experiencing, the immediate priority is efficiency and cost control. We have implemented a significant long-term cost reduction in the company through a restructuring and reduction of salary levels with cuts of 40% for top management. In addition, we are revisiting all expenses and tasks to reduce the general cost level down from USD 14 million in 2019 to USD 9 million for 2020. The Company overhead has been adapted to our current operational size, whilst ensuring the required structure to effectively execute our growth plan. Our plan to relocate from Australia this year is part of the streamlining to minimize overhead cost in the Company.

Q: What is the Company doing in response to ESG trends that have emerged in recent years?

A: The Norwegian part of PetroNor was formed on the basis of creating local growth and sustainable operations some ten years ago, way before ESG became an industry standard. In other words, we have been adhering to the individual elements of ESG for many years but are now communicating these more effectively to meet the expectations of the wider, global investor community. In Congo, PetroNor E&P is engaged in the building of schools. In Nigeria, our first project will target a significant reduction in gas flaring and aim to bring power to Lagos, a city in desperate need of an energy source to replace its current use of diesel generators. The Aje project will therefore reduce the carbon footprint significantly, whilst reducing local pollution.

Q: What is your view on climate change and its impact on your business?

A: Global climate change is a very real problem for everyone, and we recognise our role and responsibility as an energy company and steward of the environment. We believe that hydrocarbons will, and should, continue to play an important role in the global energy mix for decades to come, especially in Africa where circa 600 million people still do not have access to reliable electricity. We want to ensure our activities have a positive socioeconomic impact on the communities and countries in which we work, whilst also recognising the environmental impact of our activities. The management team has strong environmental focus and credentials, and we will always seek to display these through responsible operating activities.

Q: In terms of becoming a full-cycle E&P, what is the desired weighting between exploration, development and production?

A: The focus for the business will be on production as we believe it's important to ensure the business is supported by cash flow. As such we would envisage that weighting to be on production and development where we see near-term production. We will also engage in exploration where this makes commercial sense and the risk to our capital base is limited.

Q: Where is PetroNor E&P currently in its strategic development cycle?

A: We are really at the beginning of that cycle but have begun with a significant head-start in terms of a portfolio that already provides reliable, positive free cash flow and significant upside potential. A core aspect of our strategy is predicated on business development, and our ability to identify and execute on compelling opportunities in line with our strategic objectives. We have already executed one deal in the form of the Aje transaction, and continue to screen a strong pipeline of opportunities. We expect to be presented with an even higher volume of exciting opportunities this year and beyond, on account of the recent pressure exerted on the industry by the rapid commodity price decline.

Q: What do you consider to be the Company's key investment highlights and differentiating factors?

A: We want to build a business underpinned by cash flow and reserves, so are constantly screening opportunities to enhance both of these metrics. Needless to say, our long-term priority is to generate sustainable value for our shareholders, and with the Board and management team representing a material holding in the company, we are wholly aligned with all shareholders in this regard, and consider shareholder value in every decision we take. We believe that the knowledge and expertise of the management team and Board are core assets, especially for a company of our current size. The technical industry-knowledge we possess is extensive, and we intend to leverage this in order to identify compelling opportunities that require our technical lens to realise full potential from these assets. We also possess the requisite commercial track record, and network throughout Africa, our region of geographical focus, to source, assess and execute on transactions in line with our stated strategy.

Q: What are the biggest challenges you see on the near-term horizon?

A: The sector has numerous challenges, and these have been exacerbated by the rapid commodity price decline through early 2020. Access to cost-efficient capital is the primary challenge for our particular growth strategy, however we believe that we have the right experience, strategy and network to be able to circumnavigate these challenges. Doing business in Africa is often cited as an industry challenge, and whilst this can be very true, we believe that our experience of working across the continent holds us in good stead, and we are wholly committed to maintaining the appropriate level of Governance to ensure we will only operate in countries where we believe we can operate transparently, in line with industry best practice.

Q: What are the key considerations for you when it comes to inorganic growth?

A: We must have a laser focus on our strategic objectives and ensure that any opportunities we progress are in line with these goals. We are seeking value accretive opportunities that present us with an opportunity to leverage our deep technical and commercial expertise to extract maximum value. We also need to ensure we have conducted rigorous due diligence on target assets and pay the right price to execute on them. Clearly, we expect a lot of compelling opportunities to present themselves in this distressed market, and we must ensure we are in a position to exploit these. We hold the social and environmental impact of our operations in very high regard and these considerations will always play a major role in our execution of inorganic growth.

Q: What 3 key messages would you like shareholders to take from this Annual Report?

A: We have completed a merger between two companies and have now defined our long-term ambitious strategy; we would ultimately like to be judged on what we can deliver in terms of value creation and operational objectives over the coming years.

The industry is particularly challenging at present, and the Board is taking all appropriate measures to ensure the long-term prosperity and sustainability of our business for the benefit of all our shareholder.

We believe that we have all the elements required in terms of management, expertise, strategy, network, assets, and supportive shareholders to realise our long-term ambitions, and are subsequently uniquely placed to capitalise on the challenging market dynamics and to benefit from a once-in-a generation opportunity in the industry.

Knut Søvold,
Chief Executive Officer

Introduction

PetroNor's classification of reserves and resources complies with the guidelines established by the Oslo Stock Exchange and is based on the definitions set by the Petroleum Resources Management System (PRMS-2007), sponsored by the Society of Petroleum Engineers / World Petroleum Council / American Association of Petroleum Geologists / Society of Petroleum Evaluation Engineers (SPE / PRMS) from 2007 and 2011.

Reserves are the volume of hydrocarbons that are expected to be produced from known accumulations:

- On Production
- Approved for Development
- Justified for Development

Reserves are also classified according to the associated risks and probability that the reserves will be produced.

1P – Proved reserves represent volumes that will be recovered with 90% probability
2P – Proved + Probable represent volumes that will be recovered with 50% probability
3P – Proved + Probable + Possible volumes that will be recovered with 10% probability.

Contingent Resources are the volumes of hydrocarbons expected to be produced from known accumulations:

- In planning phase
- Where development is likely
- Where development is unlikely with present basic assumptions
- Under evaluation

Contingent Resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves.

Disclaimer

The information provided in this report reflects reservoir assessments, which in general must be recognized as subjective processes of estimating hydrocarbon volumes that cannot be measured in an exact way.

It should also be recognized that results of recent and future drilling, testing, production, and new technology applications may justify revisions that could be material. Certain assumptions on the future beyond PetroNor's control have been made. These include assumptions made regarding market variations affecting both product prices and investment levels. As a result, actual developments may deviate materially from what is stated in this report.

The estimates in this report are based on third party assessments prepared by AGR Petroleum Services AS in October 2019 for PNGF Sud and PNGF Bis.

PetroNor assets portfolio

PetroNor's assets are located approximately 25km off the coast of Pointe Noire in water depths of 80-100 metres. PetroNor, through Hemla E&P Congo (HEPCO), participated in the 2016 tender process with the Congo Ministry of Petroleum for participation in the PNGF Sud licence (brown field). HEPCO was awarded a 20% working interest in the PNGF Sud licence, corresponding to a net 10.5% to PetroNor. Furthermore, the licence partnership has, through an umbrella agreement, the right to negotiate, in good faith, the licence terms of the adjacent PNGF Bis licence, where Perenco is intended to be the operator. The umbrella agreement assigns a 28% HEPCO share to PNGF Bis, yielding a PetroNor 14.7% interest in PNGF Bis.

During 2019, PetroNor made an acquisition of a nominal 6.5% interest in OML 113 (Aje) in Nigeria from Panoro Energy. An agreement was also made between PetroNor and YFP to jointly further-develop OML 113. These agreements are described in further detail in the Directors' report. This transaction is not yet completed and is not part of this ASR statement.

During 2019, PetroNor completed a merger with African Petroleum Corporation. The merged company currently has exploration assets in Senegal and The Gambia. As these constitute prospective resources, they are not part of this ASR.

PNGF Sud: offshore Congo-Brazzaville, operator Perenco, PetroNor 10.5%.

PNGF Sud is a development and exploitation licence covering an area containing several oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi fields. The interest in PNGF Sud is held directly and with a 20% share, by Hemla E&P Conco ("HEPCO"). Through PetroNor's ownership of 52.5% of HEPCO, this constitutes an indirect 10.5% share in the PNGF Sud licence. The licence ownership has been effective since 1.1.2017 with expiry after 20 years plus a 5-year extension period. Since granting of the licence, Perenco with partner support, has been committed to strict HSE compliance while growing production, improving maintenance routines and field integrity in a stepwise and prudent manner.

In October 2019, AGR performed a full Competent Person's Report ("CPR") covering the Reserves (1P, 2P and 3P) and Resources (1C, 2C and 3C) in both PNGF Sud and PNGF Bis. The above figures were evaluated as at 31.12.18.

Gross production during 2019 was 8.0 MMbbl of oil and 0.97 Bcf of gas. This corresponds to an average 21,920 bbl/d and 2.7 mmscfd.

As per the PRMS/SPE guidelines, only the portion of gas contributing to power generation (on Tchibouela only) is included in the overall reserves in the AGR CPR. The gas is being used centrally in the field complex as fuel for power-generating turbines which is subsequently transmitted to the individual field platforms via electrical power cables. For the purpose of this report, the numbers quoted below as MMbbl do not include the oil-equivalent gas but are included in the appendix reserves and resource tables.

This PetroNor ASR uses as its basis the Reserves and Resources from the 2019 October AGR CPR, subtracting only the volumes of oil and gas produced during 2019 to arrive at the Reserves and Resources as per 31.12.19. As the only product sold is oil, PetroNor will in the text below, when referring to Reserves and Resources, mainly refer to oil and term these with the unit MMbbl.

As of 31.12.2018, AGR evaluated that gross 1P Proved Reserves yield 74.90 MMbbl in all the PNGF Sud fields in the Cenomanian and Turonian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 110.5 MMbbl in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 141.7 MMbbl.

As of 31.12.2019, by subtracting the 2019 production from the above figures, gross 1P Proved Reserves yield 66.90 MMbbl in all the PNGF Sud fields in the Cenomanian and Turonian reservoirs. Gross 2P Proved plus Probable Reserves at PNGF Sud amounted to 102.5 MMbbl in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at PNGF Sud amounted to 133.7 MMbbl.

Gross 1C Resources yield 23.0 MMbbl in all the PNGF Sud fields in the Cenomanian and Turonian reservoirs. Gross 2C Resources at PNGF Sud amounted to 29.2 MMbbl in the same reservoirs. Gross 3C Resources at PNGF Sud amounted to 51.8 MMbbl.

These evaluations yield 1P Proved Reserves net to PetroNor of 7.02 MMbbl, 2P Proved plus Probable Reserves net to PetroNor of 10.76 MMbbl and 3P Proved plus Probable plus Possible Reserves net to PetroNor of 14.04 MMbbl.

Additional potentially recoverable resources net to PetroNor are approximately 2.4 MMbbl 1C, 3.1 MMbbl 2C and 5.4 MMbbl 3C.

These Reserves and Contingent Resources are PetroNor's net volumes before deductions for royalties and other taxes, reflecting the production and cost-sharing agreements that govern the assets.

PNGF Bis: offshore Congo-Brazzaville, operator Perenco, PetroNor 14.7%.

The PNGF Bis licence neighbours the PNGF Sud licence and contains two discoveries, Louissima and Loussima SW. The two discoveries are proven by three wells including DST's drilled from 1985 to 1991. The primary potential is identified in the pre-salt Vanji formation with promising DST rates, but the exploration and appraisal wells also include an oil column in the post-salt Senji fm (not tested). A long-term test production period, with a rented jack-up with a purchase option and an 11 km pipeline tie-back to one of the existing Tchibouela wellhead platforms, is a likely scenario. This allows cost recovery of the investments during the test production and allows upscaling of production levels with additional producers as resources are matured to reserves.

Net to PetroNor 1C Contingent Resources yield 3.29 MMbbl in the Loussima SW Vanji and Senji fm. Net 2C at PNGF Bis Loussima SW amounts to 4.25 MMbbl in the same reservoirs. Net 3C amounts to 5.26 MMbbl.

Management discussion and analysis

PetroNor uses the services of AGR Petroleum Services for 3rd party verifications of its reserves and resources.

All evaluations are based on standard industry practice and methodology for production of decline analysis and reservoir modelling, based on geological and geophysical analysis. The following discussions are a comparison of the volumes reported in previous reports, along with a discussion of the consequences for the year-end 2019 ASR.

PNGF Sud: During the years 2017, 2018 and 2019, production levels have grown from the initial c. 15,000 bbl/d when Perenco and partners took over. This has materialised through revitalising existing producers via replacements or upsizing of Electrical Submersible Pumps (ESP's), acidizing, clean up or reperforating of wells or converting from the Cenomanian to the Turonian (less depleted) formations. Significant surface debottlenecking is also taking place, with projects ranging from improved power generation, gas-lift compressor upgrades, pump replacements and other surface process improvements. Production from Tchibeli has been routed to Tchendo by installing a new pipeline to avoid third party processing tariffs previously paid to the Nkossa FPSO. These brick-by-brick improvements have yielded a production level during 2019 of 21,920 bbl/d. The production improvements alone have yielded more than a 100% reserves replacement each year, at a cost of less than 2 USD/bbl. In addition to this, significant infill drilling potential has been identified in all fields. Resources identified as infill potential are classified as Contingent resources as these are most likely not decided upon until the workover potential has been exhausted.

An infill drilling programme was decided for the Litanzi field in 2019 and consequently the 2C resources in this field have been converted to 2P reserves. An infill drilling programme for Tchendo has also been approved starting investments as part of the 2020 budget, but the resources were not included as reserves at time of the CPR and are still listed as 2C resources. Development of 3D static and dynamic models has been and will continue to form the basis of further infill drilling programmes on PNGF.

PNGF Bis: Once investment decisions are made on the Loussima SW project these reserves may become reserves approved for development. A thorough mapping of the Stooip in Loussima SW has been performed by the operator in 2018. This work has been verified by AGR in the mentioned 2018 October CPR and carried on in the 2019 CPR.

Given a successful Loussima SW, a similar development potential is likely for the Loussima Discovery.

Assumptions

The commerciality and economic tests for the PNGF Sud and Bis reserves volumes were based on an oil and condensate price of 60 USD/bbl, although the reserves and resources are not very sensitive to this parameter as OPEX levels are at 12.5 USD/bbl.

2019 – 2P Reserves	(MMbbl)
Balance (gross AGR, PNGF Sud – Dec 31, 2018)	110.50
Production 2019, PNGF Sud	(8.00)
Balance 31.12.2019 – 2P gross, PNGF Sud	102.50
Balance 31.12.2019 – 2P net, PNGF Sud	10.76

2P and 2C Reserves and Resources Status	(MMbbl)
Balance 31.12.2019 – 2P/2C gross, PNGF Sud	131.70
Balance 31.12.2019 – 2P/2C net, PNGF Sud	13.83
Balance 31.12.2019 – 2P/2C gross, Sud+Bis	160.60
Balance 31.12.2019 – 2P/2C net, Sud+Bis	18.08

PetroNor’s total 1P reserves at end of 2019 amount to 7.02 MMbbl. PetroNor’s 2P reserves amount to 10.76 MMbbl and PetroNor’s 3P reserves amount to 14.04 MMbbl. This reflects the October 2019 reserve report for the PNGF Sud field, conducted by AGR Petroleum Services AS and production since the field start-up.

PetroNor’s Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By the end of 2019, PetroNor’s assets contain a total 2C volume of approximately 7.3 MMbbl.

Knut Søvold
Chief Executive Officer
6 May 2020

Reserves and resources as per 31.12.19 (AGR CPR as at 31.12.18 dated 31.10.2019 and corrected for 2019 production)

	Gross Reserves (developed or under development)									Gross Contingent Resources (undeveloped)								
	1P			**2P**			3P			1C			**2C**			3C		
	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe
PNGF Sud																		
Tchibouela	37.91	6.43	39.05	**56.61**	**10.83**	**58.53**	73.81	19.43	77.27	6.10	3.50	6.72	**8.80**	**5.00**	**9.69**	17.10	9.80	18.85
Tchendo	10.56	–	10.56	**18.96**	**–**	**18.96**	24.06	–	24.06	8.90	–	8.90	**10.70**	**–**	**10.70**	19.60	–	19.60
Tchibeli	8.13	–	8.13	**14.13**	**–**	**14.13**	18.43	–	18.43	8.00	–	8.00	**9.70**	**–**	**9.70**	15.10	–	15.10
Litanzi	10.30	–	10.30	**12.80**	**–**	**12.80**	17.40	–	17.40	–	–	–	**–**	**–**	**–**	–	–	–
Total	66.90	6.43	68.04	**102.50**	**10.83**	**104.43**	133.70	19.43	137.16	23.00	3.50	23.62	**29.20**	**5.00**	**30.09**	51.80	9.80	53.55
PNGF Bis																		
Loussima (Bis)	–	–	–	**–**	**–**	**–**	–	–	–	22.40	–	22.40	**28.90**	**–**	**28.90**	35.80	–	35.80
Total	66.90	6.43	68.04	**102.50**	**10.83**	**104.43**	133.70	19.43	137.16	45.40	3.50	46.02	**58.10**	**5.00**	**58.99**	87.60	9.80	89.35

Net to PetroNor – Reserves and resources as per 31.12.19 (AGR CPR as at 31.12.18 dated 31.10.2019 and corrected for 2019 production)

	Net PetroNor Reserves (developed or under development)									Net PetroNor Contingent Resources (undeveloped)								
	1P			**2P**			3P			1C			**2C**			3C		
	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe	Oil mmbo	Gas bcf	Boe mmboe	**Oil mmbo**	**Gas bcf**	**Boe mmboe**	Oil mmbo	Gas bcf	Boe mmboe
PNGF Sud 10.50%																		
Tchibouela	3.98	0.67	4.10	**5.94**	**1.14**	**6.15**	7.75	2.04	8.11	0.64	0.37	0.71	**0.92**	**0.53**	**1.02**	1.80	1.03	1.98
Tchendo	1.11	–	1.11	**1.99**	**–**	**1.99**	2.53	–	2.53	0.93	–	0.93	**1.12**	**–**	**1.12**	2.06	–	2.06
Tchibeli	0.85	–	0.85	**1.48**	**–**	**1.48**	1.94	–	1.94	0.84	–	0.84	**1.02**	**–**	**1.02**	1.59	–	1.59
Litanzi	1.08	–	1.08	**1.34**	**–**	**1.34**	1.83	–	1.83	–	–	–	**–**	**–**	**–**	–	–	–
Total	7.02	0.67	7.14	**10.76**	**1.14**	**10.96**	14.04	2.04	14.40	2.42	0.37	2.48	**3.07**	**0.53**	**3.16**	5.44	1.03	5.62
PNGF Bis 14.70%																		
Loussima (Bis)	–	–	–	**–**	**–**	**–**	–	–	–	3.29	–	3.29	**4.25**	**–**	**4.25**	5.26	–	5.26
Total	7.02	0.67	7.14	**10.76**	**1.14**	**10.96**	14.04	2.04	14.40	5.71	0.37	5.77	**7.31**	**0.53**	**7.41**	10.70	1.03	10.88

Oil equivalents	5.615 mscf/boe
2P Incr. from '19	26% (incl. 2019 produced volumes -8.0 MMbbl)
2C Incr. from '19	-9% (PNGF Sud only)
2C Incr. from '19	-4% (PNGF Sud and PNGF Bis)

OUR ESG COMMITMENT

PetroNor E&P is committed to operating responsibly and we endeavour to enrich the communities where we operate.

To ensure PetroNor E&P's efforts are sustainable, corporate social investments are primarily focused on project work in the following key areas:

Environmental

- We strive to minimise any adverse impact on the environment
- We always undertake Environmental Social Impact Assessments (ESIA) prior to all major activities & communicate results
- to stakeholders
- In Nigeria, our plans for the Aje project have a positive impact through the elimination of existing gas flaring (equivalent to removing the CO_2 produced by 55,000 cars)
- Gas development will also lead to displacement of gasoline used for power generation in Lagos

Social

- Our commitment to operating responsibly is evidenced by a history of social projects undertaken by the leadership
- The Power to Educate initiative is focused on improving conditions for families in areas with no access to electricity
- Other projects include human capacity development and access to quality health care
- In Congo-Brazzaville, 5% of net profits are invested in local community education initiatives

Governance

- We adhere to best practice corporate governance standards
- Our business development model includes increased access to opportunities through the formation of subsidiary companies with local partners
- This indirect ownership is supported by careful selection of local leadership and strong representation on subsidiary boards to ensure high-quality governance
- Use contemplated re-domiciliation to improve the diversity of the Board of Directors.

Case study

Power to Educate

Power to Educate is an initiative supporting education in emerging countries. Its platform is designed for companies in the oil and gas industry to help increase the number of children that receive an education.

According to the World Health Organisation (WHO), household pollution in Africa and Asia is responsible for 4.3 million deaths each year due to the use of firewood indoors. The programme and platform aim at substituting firewood with LPG, Solar and Wind solutions for domestic power usage. With no need to collect firewood, children can utilise the time to go to school.

The platform tracks the increased energy usage of LPG, Solar and Wind and measures this locally as a reduction in use of firewood. Power to Educate then awards the local communities with funds dedicated to educational programmes for each increased use of Solar, Wind and LPG.

For more: www.powertoeducate.com

Eyas Alhomouz | Non-Executive Director and Chairman

Qualifications:

Mr. Alhomouz graduated from Brigham Young University in Provo, Utah with a degree in Chemical Engineering and from the Colorado School of Mines, in Golden, Colorado with a master's degree in Mineral and Energy Economics.

Experience:

Mr. Alhomouz has strong experience from the oil and gas sector covering the United States, North Africa, and the GCC. He began his career with Schlumberger Oilfield Service as a wireline engineer in Midland, Texas. From there he went on to work for Cromwell Energy in Denver, Colorado, in the role of international business development manager. Then, as chief operating officer and finance director of Prism Seismic, he oversaw the growth of the Colorado based consulting and oil and gas software development firm, and later the acquisition of the company by Sigma Cubed where, post-acquisition of Prism Seismic, he went on to serve as a director of business development, Middle East. Mr. Alhomouz's career then took him to Qatar as general manager of Jaidah Energy, an Omani-Qatari owned company servicing the oil and gas sector in Qatar.

Knut Søvold | Executive Director and Chief Executive Officer

Qualifications:

Mr. Søvold holds a MSc in Petroleum from The Institute of Technology in Trondheim (NTH), Norway.

Experience:

Mr. Søvold has 30 years of experience in the oil and gas industry, at both executive management and technical levels. His extensive experience covers fields and licenses in the North Sea, North and West Africa, Middle East, Far East and FSU, as well as management and administration through establishing and operating companies in Norway, United Kingdom, Kazakhstan and West Africa. Mr. Søvold was in the management team of the Snorre Field in the North Sea, with a production of 200,000 bbl/d. Mr. Søvold has been working with West African assets since 2000 and in Nigeria since 2008. Furthermore, he has also been working with gas to LNG, including novel solutions such as FLNG, gas to power, as well as LNG-regasification.

Jens Pace | Non-Executive Director

Qualifications:

Mr. Pace holds a BSc in Geology and Oceanography from the University of Wales and a MSc in Geophysics from Imperial College, London.

Experience:

Mr. Pace has a background in geosciences, and has had a career spanning over 30 years at BP Exploration Operating Company Limited ("BP"), and its heritage company Amoco (UK) Exploration Company. Mr. Pace has held senior positions at BP for over 10 years, gaining exploration and production experience in Africa, namely: Algeria, Angola, Congo, Gabon and Libya. In addition, he has experience in Europe, Russia and Trinidad. He has contributed to a number of BP's exploration discoveries over his career. Most recently, Mr. Pace managed a large and active exploration portfolio for BP in North Africa. In addition to exploration activities, Mr. Pace has gained experience in the areas of field development and as a commercial manager.

Mr. Pace joined African Petroleum Corporation Ltd as Chief Operating Officer in October 2012; and was appointed Chief Executive Officer by the Board in November 2015. Following the merger with PetroNor E&P Ltd, Mr. Pace resigned as Chief Executive Officer on 29 February 2020.

Roger Steinepreis | Non-Executive Director

Qualifications:

Mr. Steinepreis holds a Bachelor of Jurisprudence and Bachelor of Laws (1985) from the University of Western Australia.

Experience:

Mr. Steinepreis is a corporate and resources lawyer with over 30 years' experience. He has acted as the legal adviser on in excess of 40 initial public offers and has advised numerous companies, large and small, on strategic acquisitions, whether by takeover, scheme of arrangement, trade sale or other means. Mr. Steinepreis serves as the executive chairman of Steinepreis Paganin, one of the largest, specialist corporate law firms in Perth, Australia, and serves on other boards.

Joseph Iskander | Non-Executive Director

Qualifications:

Mr. Iskander holds a Degree in Accounting and Finance with high distinction from Helwan University, Egypt.

Experience:

Mr. Iskander brings over 20 years of experience in the financial services industry, covering asset management, private equity, portfolio management, financial restructuring, research, banking, and audit. He began his career at Deloitte & Touche (Egypt) as an Auditor. Mr. Iskander served as non-executive director on the boards of EFG Hermes in Egypt, Oasis Capital Bank in Bahrain, Sun Hung Kai & Co. in Hong Kong, Qalaa Holdings in Egypt, Emirates Retakaful in UAE, Marfin Laiki Bank in Cyprus and Marfin Investment Group in Greece. Mr. Iskander headed the research team at Egypt's Prime Investments and was earlier an investment advisor at Commercial International Bank (CIB). He then went on and joined Dubai Group as an investment manager in 2004 and has worked on a range of M&A transactions, advisory services, asset management, and private equity transactions with a collective value in excess of USD 8 billion. Mr. Iskander was managing director of Asset Management at Dubai Group and the former head of research at Dubai Capital Group until 2009. He joined Emirates International Investment Company in July of 2017 as the director of private equity spearheading and managing EIIC's investments.

Alexander Neuling | Non-Executive Director

Qualifications:

Mr. Neuling holds a BSc (Hons) in Chemistry from Leeds University, United Kingdom and he is a Fellow of the Institute of Chartered Secretaries and Administrators and a Fellow of the Institute of Chartered Accountants of England & Wales.

Experience:

Mr. Neuling is a chartered accountant and has been advising within extractive industries for more than 15 years. Mr. Neuling has held numerous senior management positions at listed companies, and previously worked for Deloitte in London and Perth.

Your Directors present their report on PetroNor E&P Limited ("PetroNor" or the "Company") for the year ended 31 December 2019.

Directors

The names of Directors in office during the financial year and until the date of this report are as follows. Directors were in office for this entire period unless otherwise stated.

E Alhomouz	Non-Executive Chairman, appointed 30 August 2019
K Søvold	Executive Director, appointed 30 August 2019 Chief Executive Officer, appointed 29 February 2020
J Pace	Executive Director and Chief Executive Officer, resigned 29 February 2020 Non-Executive Director, appointed 29 February 2020
S West	Executive Director and Chief Financial Officer, resigned 29 February 2020
J Iskander	Non-Executive Director, appointed 30 August 2019
A Neuling	Non-Executive Director, appointed 6 April 2020
R Steinepreis	Non-Executive Director, appointed 6 April 2020
D King	Non-Executive Director, resigned 1 February 2020
B Moe	Non-Executive Director, resigned 18 October 2019
T Turner	Non-Executive Director, resigned 8 February 2020

The names of Directors for the Cypriot Company, PetroNor E&P Ltd, during the financial year and until the merger with the Company on 30 August 2019 are as follows:

E Alhomouz	Director
K Søvold	Director
G Ludvigsen	Director
H Marshad	Director, appointed 26 February 2019
A Georghiou	Director, appointed 17 April 2019
N Kouyialis	Director, appointed 17 April 2019

Company Secretary

Ms. Angeline Hicks

Principal activity

The Company's principal activity during the year was oil and gas exploration and production.

Review of operations

Corporate

PetroNor E&P and African Petroleum Merger

On 19 March 2019, the Company (previously called African Petroleum Corporation Limited) entered into a combination agreement with Cypriot company PetroNor E&P Ltd and its shareholders NOR Energy AS ("NOR") and Petromal – Sole Proprietorship LLC ("Petromal").

The transaction completed on 30 August 2019, with 816,198,842 new shares in the Company issued to NOR and Petromal as consideration to acquire 100% of the shares in the Cypriot company. The consideration for the transaction also included 155,466,446 warrants with a nil exercise price and were subject to vesting conditions dependent on a) a signed acquisition / farm-in agreement for a gas asset in Nigeria, and b) a signed gas offtake agreement relating to the gas from the asset. All the warrants expired on 31 December 2019, as the vesting conditions had not occurred.

The transaction transformed the Company into a full-cycle E&P company.

The transaction was considered a reverse acquisition, and consequently the Annual Report and Financial Statements are prepared as a continuance of the operations of the Cypriot company. Additional details on the accounting policies are provided in Note 3.

Operational updates

Republic of Congo – PNGF Sud

PNGF Sud fields are located approximately 25 km off the coast of Pointe-Noire in water depths of 80 to 100 metres. PNGF Sud comprises 3 operating licenses, Tchibouela II, Tchendo II and Tchibeli-Litanzi II, covering five oil fields: Tchibouela Main, Tchibouela East, Tchendo, Tchibeli and Litanzi.

PetroNor, through Hemla E&P Congo, participated in the 2016 tender process with the Congo Ministry of Hydrocarbon for participation in the PNGF Sud licence. As of 1 January 2017, Hemla E&P Congo was awarded a 20% working interest in the PNGF Sud licenses (net 10.5% to PetroNor).

Initially discovered in 1979, PNGF Sud commenced production in 1987 and produces from 61 wells in five oil fields, Tchibouela, Tchibouela East, Tchendo, Tchibeli and Litanzi.

Following the entry of the new licence group in 2017, significant operational improvements have been made, increasing gross production from c. 15,000 bbl/d in January 2017. The average production in 2019 was 21,920 bbl/d. Through further workovers, surface and process improvements and infill drilling, gross production from PNGF Sud is expected to continue to grow in the coming years.

The PNGF Sud fields are developed with seven wellhead platforms and currently produce from more than 60 active production wells, with oil exported via the onshore Djeno terminal (Tchibouela, Tchendo and Tchibeli) and the Nkossa FPSO (Litanzi). With its long production history, substantial well-count and extensive infrastructure, PNGF Sud offers well-diversified and low-risk production and reserves with low break-even costs.

In October 2019, AGR Petroleum prepared a Competent Person's Report and the reserves below are calculated to 31.12.2019 by subtraction of the production between the cut-off date of the CPR report and year-end 2019.

PetroNor´s Reserves at 31.12.2019

- 1P reserves of 7.02 MMbbl
- 2P reserves of 10.76 MMbbl
- 3P reserves of 14.04 MMbbl

PetroNor's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By the end of 2019, PetroNor's assets contained a total 2C volume of approximately 7.3 MMbbl.

During 2019, the gross production was 8.0 MMbbl of oil and 0.97 Bcf of gas, resulting in a net to PetroNor of 2.4 MMbbl.

Republic of Congo – PNGF Bis

PNGF Bis is located to the North-West of PNGF Sud and comprises 2 discoveries: Loussima SW and Loussima.

Through an umbrella agreement, the licence partners of PNGF Sud have the right to negotiate, in good faith, the licence terms to enter into a PSC for PNGF Bis. Subject to successful completion of negotiations, PetroNor is expected to hold a 14.7% indirect interest.

Three exploration wells have been drilled on the licence area. A discovery in pre-salt Vandji Fm was made in well LUSM-1 on Loussima in 1985. Loussima SW was discovered by well LUSOM-1 in 1987 with oil in Vandji Fm.

A second well, SUEM-2, was drilled on Loussima SW in 1991 to appraise the Vandji discovery. Hydrocarbon shows were detected in one of the wells in the Albian post-salt Sendji Fm, (analogue to Tchibeli / Litanzi reservoirs in PNGF Sud). The Sendji interval was not production-tested. The depth to the Vandji reservoir is 3,250 mTVDSS, to Sendji around 1,940 mVDSS and the water depth in the area is 110 m. Tests on the Loussima SW LUSOM-1 well produced 4,700 bbl/d and the SUEM-2 well yielded 1,150 bbl/d.

The CPR report prepared by AGR estimates that PNGF Bis holds gross 2C resources of 28.9 MMbbl.

Senegal – ROP & SOSP

The Company's subsidiary African Petroleum Senegal Limited registered a request for arbitration proceedings with ICSID on 11 July 2018 (ICSID case ARB/18/24) to protect its interests in the Senegal Offshore Sud Profond ("SOSP") and Rufisque Offshore Profond ("ROP") blocks in Senegal.

During the year, the matter followed procedural timeframes, with the Company filing a memorial on the merits on 19 July 2019, and the Senegalese Government filed a counter-memorial on the merits of the case on 9 December 2019.

The Company remains open to engaging in constructive dialogue with the Senegalese authorities through appropriate and official channels, with a view to establishing a satisfactory solution that is in the interests of all parties.

Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Senegal Licences and estimates the net unrisked mean prospective oil resources at 1,779 MMbbl.

The Gambia – A1 & A4

The Company's subsidiary African Petroleum Gambia Limited initiated arbitration proceedings at the International Centre for the Settlement of Investment Disputes ("ICSID") which were registered on 17 October 2017 to protect its interests in the A1 and A4 licences in The Gambia (ICSID case ARB/17/38).

During the year, the matter also followed procedural timeframes, with the Company filing a memorial on the admissibility, jurisdiction and the merits on 28 February 2019, and the Gambian Government filed a counter-memorial on the admissibility, jurisdiction and the merits of the case on 12 July 2019.

Post year-end, on 10 January 2020 the Company filed a reply, and in turn the Gambian Government filed a rejoinder on 24 March 2020.

The Company remains open to engaging in constructive dialogue with the Gambian authorities, with a view to establishing a satisfactory solution that is in the interests of all parties.

Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Gambian licences and estimates the net unrisked mean prospective oil resources at 3,079 MMbbl.

Nigeria – OML 113 The AJE Field

PetroNor entered into an agreement with Panoro Energy and Yinka Folawiyo Petroleum ("YFP") to acquire Panoro's interest in the OML 113 and the Aje field in Nigeria in October 2019. PetroNor and YFP have formed a joint company, Aje Petroleum, to focus on the revitalisation and further development of OML 113. The ownership of Aje Petroleum is to be shared between YFP and PetroNor on the basis of a 55% and 45% shareholding respectively.

Following completion, Aje Petroleum will hold a 75.5% participating interest and an average economic interest in the order of 38.7% in OML 113, with an initial 29% economic interest at the onset of the transaction. Additional details on licence interests are provided in the attached appendix.

YFP, as the operator of OML 113, will engage Aje Petroleum as a technical service company.

The completion of the YFP Agreement is subject to authorisation of the Nigerian Department of Petroleum Resources and consent of the Minister of Petroleum Resources.

The Aje Field will be redeveloped through drilling of additional gas and oil wells by extraction of liquid condensate offshore before an eventual tie-back of gas to shore. Significant additional contingent resources exist in the Aje field. Above the Turonian oil rim, from which circa half of today's production is produced, is a significant undeveloped gas-condensate discovery. Additional contingent resources have been identified in both the Turonian oil rim and the underlying Cenomanian sands from which the other half of today's production is extracted.

A staged development is planned to exploit the contingent resources in a manner which reduces development risk. The initial phase constitutes drilling of gas injection and production wells to allow offshore extraction of condensate. This is estimated to more than double today's liquid production in addition to removing the current gas flaring in the field today. The secondary objective of the gas wells is to appraise for the best location of additional oil well(s) in the Turonian or Cenomanian. This condensate stripping may be regarded a stand-alone development, and can continue until a development decision on phase 2, involving a gas pipeline to shore for export to power, or even construction of a gas plant for removing additional liquid components before selling the dry gas to power.

The Aje field has a current gross production of circa 2,300 bbl/d with remaining reserves of 2.3 MMbbl. This corresponds to 301 bbl/d production and 0.3 MMbbl net to PetroNor at a current economic interest of 13.1%. The above development plan entails a gross 2C resource of circa 110 MMbbl (gas and condensate). With an economic interest after development of 17.4%, this corresponds to some 19 MMbbl net to PetroNor.

Result

The Board of Directors (the "Board") confirms that the annual financial statements have been prepared pursuant to the going concern assumption. The continuing impact that Covid-19 will have on the Group's operations and the global markets, plus the uncertainty on the Group's ability to renegotiate outstanding payables to significant shareholders, indicate material uncertainties on the status of going concern. The going concern assumption is based upon the financial position of the Group and the development plans currently in place. In the Board of Directors' view, the annual financial statements give a true and fair view of the Group's assets and liabilities, financial position and results. PetroNor E&P Limited is the parent company of the PetroNor Group (the "Group"). Its financial statements have been prepared on the assumption that PetroNor will continue as a going concern.

The Group had USD 27.9 million in cash and bank balances as of 31 December 2019 (2018: USD 7.9 million).

PetroNor E&P Limited prepares its financial statements in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report also complies with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

The consolidated financial statements are presented in US dollars.

Financial performance and activities

The Group reported an EBITDA of USD 49 million for the year ended December 31, 2019, compared to USD 53.10 million in the same period in 2018. Net loss attributable to the equity holders of the parent was USD 13.36 million for 2019, compared to net profit of USD 7.84 million in 2018. The decrease in profit is predominantly due to the recognition of a share-based payment expense of USD 19.4 million in the current year for the reverse acquisition transaction. Additional details providing the recognition rationale and subsequent disclosure are in Note 23a of the financial statements.

Oil and gas revenue in the year was (net of royalties and taxes) USD 57.5 million arising from sale of 0.88 million barrels of crude oil at an average price of 65.25 USD per barrel. The revenue increased by 5.1% as compared to last year. There is an 8.5% increase in the oil production and a 3.4% decrease in the price, as compared to 2018.

EBITDA margin of 47.7% is slightly lower as compared to last year's 52.5%, mainly because of the business development and legal and professional expenses incurred during 2019. The operational efficiency of the asset in Congo has improved.

Intangible non-current assets of USD 4.7 million, represent the previous tender costs, entry bonus and signature bonus paid in 2017 to acquire the share in PNGF Sud.

The production assets and equipment balance of USD 22.6 million, included additional CAPEX investment of USD 12.3 million in the PNGF Sud licence during the year.

Allocation of profits and losses

Funding

During the year, the Company renegotiated the terms and extended the credit of a short-term debt facility of USD 12.9 million from Rasmala (London and Dubai based investor group). The loan was replaced in May 2020 with a USD 15 million facility with 12 months' grace period and final maturity date in October 2022.

Dividends paid or recommended

During the year no dividend was paid or recommended. However, part of the consideration for the merger, stipulated a USD 11.5 million cash element to represent the net share distribution of profits from 2018 generated by the operating subsidiary Hemla E&P Congo SA. This cash element of the merger consideration has been classified as a dividend that was approved on the date of the merger. As at 31 December 2019, only USD 1.1 million of the cash consideration had been paid, with the USD 10.4 million outstanding and included as part of the balance payable to related parties.

Risk factors

Operational risk factors

The development of oil and gas fields in which the Company is involved is associated with technical risk, alignment in consortiums with regards to development plans, and on obtaining necessary licences and approvals from the authorities. Disruptions of operations might lead to cost overruns and production shortfall, or delays compared to the schedules laid out by the operator of the fields. Post year-end, COVID-19-linked restrictions on social mobility imposed by worldwide governments may generate workforce shortages, with disruptions expected for maintenance, inspection, repair and replacement of equipment and drilling activities. As a non-operator for the Congo licences, the Group has limited influence on operational risks related to exploration and development of the licences and fields in which it has interests.

The PNGF Sud licences have been developed since 1987 and thus significant caution has to be taken by the operator to ensure that the old facilities are properly maintained.

The development of the oil fields, in which the Group has an ownership, is associated with significant technical risk and uncertainty with regards to the timing of additional production from new development activities. The PNGF Bis licence is still under negotiations and the contractor group may not reach an agreement with the government.

The Group's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with third parties will be dependent upon developing and maintaining close working relationships with industry partners, joint operators and authorities, as well as its ability to select and evaluate suitable properties, and complete transactions in a highly competitive environment.

Business risk factors

The Group's revenues, cash flow, reserve estimates, profitability and rate of growth depend substantially on prevailing prices of oil and gas, which may fluctuate significantly based on factors beyond the Group's control. Post year-end, the dramatic decline in the oil price demonstrates the volatility in the market, and the difficulty to accurately predict future oil and gas price movements.

Sustained lower oil and gas prices may lead to a material decrease in the Group's net production revenues and may also cause the Group to make substantial downward adjustments to its oil and gas reserves. If oil and gas prices remain depressed over time, it could also reduce the Group's ability to raise new debt or equity financing or to refinance any outstanding loans on terms satisfactory, or at all.

Financial risk factors

The overall risk management programme seeks to minimize the potential adverse effects of unpredictable fluctuations in financial markets on financial performance, ie, risks associated with currency exposures, and debt-servicing. Financial instruments such as derivatives, forward contracts and currency swaps are continuously being evaluated for the hedging of such risk exposures.

Due to the international nature of its operations, the Group is exposed to risk arising from currency exposure, primarily with respect to the Norwegian Kroner (NOK) and the Great British Pound (GBP).

The Group currently has a debt facility with Rasmala and as part of the group strategy to target new projects, it will need to raise further capital. Should additional funding be required in the future for additional capital expenditure for new development phases or working capital requirements, the Group has various alternatives available which it can explore to fulfil such additional requirements. The options include, amongst others, ordinary debt financing, Nordic Bonds, reserves-based lending, project financing, off-take prepayment structures, and the issuance of shares.

Corporate Governance

The main objective for PetroNor's corporate governance is to develop a strong, sustainable, competitive and successful E&P group acting in the best interest of all the stakeholders, within the laws and regulations of the countries where it operates. The Board and management aim for a controlled and profitable development and long-term creation of growth through well-founded governance principles and risk management.

Given its Australian domicile and former NSX listing, the Company's corporate governance framework has been constructed in recognition of, and with regard to, the Australian Corporations Act; the ASX Corporate Governance Council's ("CGC") 'Principles of Good Corporate Governance and Best Practice Recommendations' (Recommendations) and CGC published guidelines; and an extensive range of varying legal, regulatory and governance requirements applicable to publicly-listed companies in Australia. The Board of Directors supports the principles of effective corporate governance and is committed to adopting high standards of performance and accountability, commensurate with the size of the Company and its available resources. Accordingly, the Board of Directors has adopted corporate governance principles and practices designed to promote responsible management and conduct of the Company's business. The current corporate governance plan adopted by the Company is available on the Company's website at www.PetroNorep.com. The Company is in compliance with the NSX Corporate Governance Principles. With the listing on Oslo Axess, the Board acknowledges the Norwegian Code of Practice for Corporate Governance and the principle of "comply or explain". The Group has implemented a policy for Ethical Code of Conduct and works diligently to comply with these guidelines.

Discrimination and equal employment opportunities

PetroNor is an equal opportunity employer, with an equality concept integrated in its human resources' policies. A diversified working environment is embraced, and the Group's personnel policies promote equal opportunities and rights and prevent discrimination based on gender, ethnicity, colour, language, religion or belief. All employees are governed by PetroNor's Code of Conduct, to ensure uniformity in behaviour across a workforce representing a multitude of nationalities.

PetroNor is a knowledge-based group in which a majority of the workforce has earned college or university level educations; or has obtained industry-recognised skills and qualifications specific to their job requirements. Employees are remunerated exclusively based upon skill level, performance and position.

Proportion of local West African employees:

	Actual	Objective
Organisation as a whole	50%	50%
Board	Nil	+20%

Proportion of women:

	Actual	Objective
Organisation as a whole	29%	+20%
Executive management team	Nil	+20%
Board	Nil	40%

Share capital

The Company's share capital consists entirely of 971,665,288 ordinary shares. Over 98.08% of the Company's ordinary shares are admitted for trading on the Oslo Axess (Norway). During the year 816,198,842 shares were issued as part of the consideration to purchase the entire share capital of PetroNor E&P Ltd, a company registered in Cyprus.

> Cypriot Company, PetroNor E&P Ltd has 100,000 ordinary shares of nominal value EUR1 (USD 1.20) each.

Rights and obligations of shareholders

In accordance with section 5-8a of the Norwegian Securities Trading Act, the Company provides the following information:

a. there are no restrictions on the transfer of securities;
b. no holders of any securities have special control rights;
c. the Company does not operate an employee share scheme;
d. there are no restrictions on voting rights;
e. there are no agreements between shareholders which are known to the Company and which may result in restrictions on the transfer of securities and/or voting rights within the meaning of Directive 2001/34/EC;
f. the Company's Constitution provides that the Board of Directors shall have no fewer than 3 Directors and no more than 12 Directors. The Directors are elected by a general meeting of shareholders by ordinary resolution. Additionally, pursuant to Clause 13.4 of the Constitution, the Board of Directors may at any time appoint a person to be a Director, provided that the maximum number of Directors is not exceeded. Any such Director appointed will hold office until the next general meeting and will be eligible for reelection. At the Company's Annual General Meeting, one-third of the Directors for the time being, shall retire from office, provided always that no Director except a Managing Director shall hold office for a period in excess of three years without submitting him or herself for reelection. The Directors to retire at an Annual General Meeting are those who have been longest in office since their last election. A retiring Director is eligible for reelection. In the event of equal voting at a Directors' meeting, the Chairman of the meeting shall have a second or casting vote providing there is more than two directors competent to vote on the question. As the Company is incorporated in Australia, the Australian Corporations Act requires the Company to have at least two Directors that reside in Australia.
g. the Company may modify or repeal its constitution or a provision of its constitution by special resolution of shareholders;
h. pursuant to section 198A of the Australian Corporations Act,

the business of a company is managed by or under the direction of the Board of Directors. Pursuant to Clause 2.2 of the Company's Constitution, the Board of Directors has the power to issue shares;

i. subject to the requirements in the Australian Corporations Act, the Company may purchase its own shares in accordance with the buy-back provisions of the Australian Corporations Act, on such terms and at such times as may be determined by the Directors from time to time and approved by the shareholders as required pursuant to the Australian Corporations Act. The Company is not entitled to hold its own shares, subject to exceptions set out in Section 259A of the Australian Corporations Act. Any shares repurchased by the Company will need to be cancelled;

j. there are no significant agreements to which the Company is a party and which take effect, alter or terminate upon a change of control of the Company following a takeover bid;

k. there are no agreements between the Company and its Board members or employees providing for compensation if they resign or are made redundant without valid reason or if their employment ceases because of a takeover bid.

As at 16 April 2020, the Company had 3,067 shareholders and 971,665,288 shares, with 99.7% registered in the Verdipapirsentralen (VPS) - Norwegian Central Securities Depository. The table below shows the 20 largest shareholders in the Company, as at 16 April 2020.

#	Shareholder	Number of Shares	Per cent
1	Nor Energy AS	444,237,596	45.72
2	Petromal LLC	371,961,246	38.28
3	Nordnet Bank AB	13,289,774	1.37
4	Telinet Energi AS	12,864,541	1.32
5	Nordnet Livsforsikring AS	6,773,764	0.70
6	Avanza Bank AB	5,910,273	0.61
7	Gekko AS	3,948,253	0.41
8	Danske Bank A/S	3,539,789	0.36
9	UBS Switzerland AG	2,365,979	0.24
10	Ole Andreas Baksaas	2,271,809	0.23
11	Nordea Bank Abp	2,170,028	0.22
12	Sandberg JH AS	2,000,000	0.21
13	Swedbank AB	1,856,743	0.19
14	Roger Nordvedt	1,734,685	0.18
15	John Andreas Rognstad	1,700,000	0.17
16	Frank Kristian Ludvigsen	1,673,000	0.17
17	Minh Hoang Pham	1,590,000	0.16
18	Jens Pace[1]	1,498,938	0.15
19	Cresthaven Investments Pty Ltd	1,377,544	0.14
20	Øystein Brustad	1,350,000	0.14
	Subtotal	**884,113,962**	**90.99**
	Others	87,551,326	9.01
	Total	**971,665,288**	**100.00**

1 Mr. Pace's shares are not registered in the VPS; and are held as paper certificates provided by the Company when it delisted from the NSX in Australia.

Directors

The Company has six Directors at the Board. The Directors have various backgrounds and experience, offering the Group and the Company valuable perspectives on industrial, operational and financial issues.

Director	Interest in shares and options:
Eyas Alhomouz Non-Executive Director and Chairman	As at the date of this report, although Mr. Alhomouz has no personal interests in shares and options, he has influence over 371,961,246 shares as the CEO of significant shareholder Petromal LLC.
Knut Søvold Executive Director and Chief Executive Officer	As at the date of this report, 444,237,596 shares are held by NOR Energy AS, a company controlled jointly by Mr. Søvold and Mr. Ludvigsen through an indirect beneficial interest. Mr. Ludvigsen is also a member of key management.
Joseph Iskander Non-Executive Director	As at the date of this report, Mr. Iskander has no interests in shares and options.
Jens Pace Non-Executive Director	As at the date of this report, Mr. Pace holds 1,498,938 shares.
Roger Steinepreis Non-Executive Director	As at the date of this report, Mr. Steinepreis has no interests in shares and options.
Alexander Neuling Non-Executive Director	As at the date of this report, Mr. Neuling has no interests in shares and options.
Dr David King Non-Executive Director	As at the date of resignation, Dr. King held 30,000 shares.
Stephen West Executive Director and Chief Financial Officer	As at the date of resignation, Mr. West held 1,377,544 shares. Mr. West's shares were held in the name of Cresthaven Investments Pty Ltd, a company in which Mr. West has an indirect beneficial interest.
Timothy Turner Non-Executive Director	As at the date of resignation, Mr. Turner held an interest in 4,167 fully paid ordinary shares.

Company Secretary

Angeline Hicks is a Chartered Accountant with global corporate and financial experience. After gaining her qualifications at Deloitte, Ms. Hicks furthered her career in the banking industry in London for eight years, working for investment banks such as Barclays Capital, Credit Suisse and JP Morgan, focusing on managing compliance and corporate and financial reporting. Ms. Hicks is an Associate of the Governance Institute of Australia and also performs the role of Company Secretary for companies listed on the Australian Securities Exchange.

Meetings of Directors

The number of Directors' meetings (including committees) held during the period each Director held office during the financial year and the number of meetings attended by each Director is shown below:

	Audit Committee Meetings		Directors' Meetings	
Director	Eligible to attend	Attended	Eligible to attend	Attended
E Alhomouz	–	–	3	3
K Søvold	–	–	3	3
J Pace	–	1	4	4
S West	–	1	4	4
J Iskander	–	–	3	3
D King	1	1	4	2
B Moe	1	1	3	3
T Turner	1	1	4	4

Cyprus company, PetroNor E&P Ltd

	Directors' Meetings	
Director	Eligible to attend	Attended
E Alhomouz	6	5
K Søvold	6	6
G Ludvigsen	6	6
A Georghiou	5	5
N Kouyialis	5	5
H Marshad	5	4

In addition to meetings of Directors held during the year, due to the number and diversified location of the Directors, a number of matters are authorised by the Board of Directors via circulating resolutions. During the current year, two circulating resolutions were authorised by the Board of Directors. There were no Remuneration Committee or Continuous Disclosure Committee meetings during the year, as any relevant matters were discussed during the Directors' Meetings.

Indemnifying Directors and officers

In accordance with the Constitution, except as may be prohibited by the Corporations Act 2001, every Director, principal Executive Officer or Secretary of the Company shall be indemnified out of the property of the Company against any liability incurred by him in his capacity as Director, principal Executive Officer or Secretary of the Company or any related corporation in respect of any act or omission whatsoever and howsoever occurring or in defending any proceedings, whether civil or criminal.

Indemnification of auditors

To the extent permitted by law, the Company has agreed to indemnify its auditors, BDO Audit (WA) Pty Ltd ("BDO"), as part of the terms of its audit engagement agreement against claims by third parties arising from the audit (for an unspecified amount). No payment has been made to indemnify BDO during or since the financial year.

Health, Safety and Environment

Health, Safety and Environment (HSE) policies are essential for PetroNor with the goal to avoid accidents and incidents and minimize the impact of its activities on the environment. PetroNor performs all its activities with focus on and respect for people and the environment. The Board believes this is a key condition for creating value in a very demanding business. The Group's objective for health, environment, safety and quality (HSEQ) is zero accidents and zero unwanted incidents in all activities. The Group strives towards performing all its activities with no harm to people or the environment. PetroNor experienced no accidents, injuries, incidents or any environmental claims during the year.

Time lost due to employee illness or accidents was negligible. Employee safety is of the highest priority, and the Group is continuously working towards identifying and employing administrative and technical solutions that ensure a safe and efficient workplace.

The Group is in the process of establishing a set of operational guidelines building on its principles of Corporate Governance, covering critical operational aspects ranging from ethical issues and practical travel advice to delegation of authority matrices.

The oil and gas assets located in West Africa imply frequent travel, and the Group seeks to ensure adequate safety levels for management and employees travelling.

With its non-operated licences, PetroNor is dependent on the efforts of the operators with respect to achieving physical results in the field. However, the Group has chosen to take an active role in all licence committees with the conviction that high safety standards are the best means to achieve successful operations. Through this involvement, the Group can influence the choice of technical solutions, vendors and quality of applied procedures and practices.

The Group's operations have been conducted by the operators on behalf of the licensees, at acceptable HSE standards and the Operator of PNGF Sud is reporting regularly on all key HSE indicators. No accidents that resulted in loss of human lives or serious damage to people or property have been reported.

In October 2019, Non-Executive Director Bjarne Moe sadly passed away unexpectedly. Bjarne had been a valuable contributor towards the Company since joining the Board of what was then African Petroleum in 2013.

To the best of the Group's knowledge, all operations have been conducted within the limits set by approved environmental regulatory authorities.

The Company is aware of its environmental obligations with regards to its exploration activities and ensures that it complies with the relevant environmental regulations when carrying out any exploration work. There have been no significant known breaches of the Company's exploration licence conditions or any environmental regulations to which it is subject.

Significant changes in the state of affairs

There have been no significant changes in the Company's state of affairs during the current year.

Options

Unissued shares under option

At the date of this report unissued ordinary shares of the Company under option are:

Expiry date	Exercise price/NOK	Exercise price /USD equivalent at 31 December 2019	Number under option
15 November 2020	1.70	0.19	190,000
22 December 2020	1.70	0.19	700,000
11 January 2022	2.50	0.28	213,400
31 May 2022	7.75	0.88	1,176,070
Total			**2,279,470**

Shares issued on the exercise of options

During the current year, no ordinary shares were issued on the exercise of options (2018: nil).

Proceedings on behalf of Company

No person has applied for leave of Court to bring proceedings on behalf of the Company or intervene in any proceedings to which the Company is a party for the purpose of taking responsibility on behalf of the Company for all or any part of those proceedings.

The Company was not a party to any such proceedings during the year.

Significant events after the balance date

Board restructure

On 29 February 2020, Jens Pace stepped down as Chief Executive Officer but remained on the Board as a Non-Executive Director. Chief Operating Officer, Knut Søvold, was immediately appointed the Chief Executive Officer. Also, on 29 February 2020, Stephen West resigned as the Chief Financial Officer and Executive Director.

Non-Executive Directors David King and Tim Turner resigned during February 2020 and were replaced by Alexander Neuling and Roger Steinepreis in April 2020.

COVID-19

Since the end of financial year, the COVID-19 outbreak is a globally-significant event impacting the health of individuals, international trade and commerce and, as a result, had a severely negative impact on global financial markets. The COVID-19 outbreak combined with the dramatic oil price decline has had a significant impact on the short-term oil prices. Consequently, this has adversely affected the Group's business.

The Company has initiated an immediate cost reduction in the Company's overheads and general administration costs. The key management salaries have been reduced with immediate effect from mid-March 2019. A full review of the Company's expenditures has been completed and cost reduction actions are implemented on a continuous basis. It has been important for the management to ensure that the cost savings initiatives have limited impact on the capabilities of the Company to continue its growth strategy even under these difficult circumstances and the new venture strategy of the Company. The implemented initiatives will reduce the "normal budget" for 12 months forward from USD 14.1 million to USD 10.5 million. This excludes any ongoing commitments such as redundancy packages and other costs which will be tapered down, going forward.

Arbitration

On 4 May 2020, the arbitration proceedings for the Group's interests in Senegal were suspended until 2 November 2020, following a mutual agreement between the parties.

Likely developments and expected results

Due to the COVID-19 outbreak and subsequent travel restrictions, the Company expects to be able to receive the governmental approval of the Aje transaction during H2 2020.

The Board wishes to thank the staff, consultants, services providers and shareholders for their continued commitment to the Company.

Auditor's independence declaration

The auditor's independence declaration for the year ended 31 December 2019 has been received and can be found on page 32 of the annual report.

Non-audit services

Non-audit services were provided by the entity's auditor's BDO, as per Note 8b. The Directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

This report is made in accordance with a resolution of the Board of Directors.

Knut Søvold
Director & Chief Executive Officer
6 May 2020

Declaration of independence
by Phillip Murdoch to the Directors of PetroNor E&P Limited

As lead auditor of PetroNor E&P Limited for the year ended 31 December 2019, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the *Corporations Act 2001* in relation to the audit; and
2. No contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of PetroNor E&P Limited and the entities it controlled during the period.

Phillip Murdoch
Director

BDO Audit (WA) Pty Ltd
Perth, 6 May 2020

Consolidated statement of profit or loss and other comprehensive income

	Note	2019 USD'000	2018 USD'000
Revenue	5	**102,760**	101,069
Cost of sales	6	**(37,207)**	(41,577)
Gross profit		**65,553**	59,492
Other operating income	7	**9**	491
Administrative expenses	8	**(19,793)**	(10,090)
Profit from operations		**45,769**	49,893
Finance expense	9	**(1,822)**	(1,623)
Finance income		**–**	–
Foreign exchange loss		**(440)**	(88)
Share based payment	23	**(19,374)**	–
Profit before tax		**24,133**	48,182
Tax expense	10	**(29,894)**	(31,124)
(Loss) / profit for the year		**(5,761)**	17,058
Other comprehensive income:			
Exchange gains arising on translation of foreign operations		**–**	–
Total comprehensive (loss) / income		**(5,761)**	17,058
(Loss) / spaces either side of / profit for the year attributable to:			
Owners of the parent		**(13,364)**	7,838
Non-controlling interest		**7,603**	9,220
		(5,761)	17,058
Total comprehensive (loss) / income attributable to:			
Owners of the parent		**(13,364)**	7,838
Non-controlling interest		**7,603**	9,220
		(5,761)	17,058
		USD cents	USD cents
Earnings per share attributable to members:			
Basic and diluted (loss)/profit per share	11	**(1.17)**	0.96

The accompanying notes form part of these financial statements

Consolidated statement of financial position

	Note	As at 31 December 2019 USD'000	As at 31 December 2018 USD'000
Assets			
Current assets			
Inventories	12	**3,233**	2,570
Trade and other receivables	13	**24,772**	28,210
Cash and cash equivalents	14	**27,891**	7,926
		55,896	38,706
Non-current assets			
Property, plant and equipment	16	**22,587**	12,580
Intangible assets	17	**4,691**	5,565
		27,278	18,145
Total assets		**83,174**	56,851
Liabilities			
Current liabilities			
Trade and other payables	18	**34,602**	9,653
Loans and borrowings	19	**12,941**	5,000
		47,543	14,653
Non-current liabilities			
Loans and borrowings		**–**	2,083
Provisions	20	**14,373**	13,496
		14,373	15,579
Total liabilities		**61,916**	30,232
NET ASSETS		**21,258**	26,619
Issued capital and reserves attributable to owners of the parent			
Share capital	21	**17,735**	120
Retained earnings	22	**(11,226)**	13,688
		6,509	13,808
Non-controlling interests		**14,749**	12,811
TOTAL EQUITY		**21,258**	26,619

The accompanying notes form part of these financial statements

The financial statements were approved and authorised for issue by the Board of Directors on 6 May 2020 and were signed on its behalf by Knut Søvold.

Consolidated statement of changes in equity

	Note	Issued capital USD'000	Share-based payment reserve USD'000	Foreign currency translation reserve USD'000	Retained earnings USD'000	Non-controlling interest USD'000	Total USD'000
BALANCE AT 1 JANUARY 2019		**120**	**–**	**–**	**13,688**	**12,811**	**26,619**
(Loss) / profit for the year		**–**	**–**	**–**	**(13,364)**	**7,603**	**(5,761)**
Other comprehensive income		**–**	**–**	**–**	**–**	**–**	**–**
Total comprehensive loss for the year		**–**	**–**	**–**	**(13,364)**	**7,603**	**(5,761)**
Issue of capital	21	**17,615**	**–**	**–**	**–**	**–**	**17,615**
Exercise of share options		**–**	**–**	**–**	**–**	**–**	**–**
Dividends paid during the year		**–**	**–**	**–**	**(11,550)**	**(5,665)**	**(17,215)**
Share-based payments		**–**	**–**	**–**	**–**	**–**	**–**
BALANCE AT 31 DECEMBER 2019		**17,735**	**–**	**–**	**(11,226)**	**14,749**	**21,258**
For the year ended 31 December 2018							
BALANCE AT 1 JANUARY 2018		120	–	–	5,580	5,713	11,683
Profit for the year		–	–	–	7,838	9,220	17,058
Other comprehensive income		–	–	–	–	–	–
Total comprehensive loss for the year		120	–	–	7,838	9,220	17,058
Issue of capital		–	–	–	–	3	3
Exercise of share options		–	–	–	–	–	–
Dividends paid during the year		–	–	–	–	(2,125)	(2,125)
Share-based payments		–	–	–	–	–	–
BALANCE AT 31 DECEMBER 2018		120	–	–	13,688	12,811	26,619

The accompanying notes form part of these financial statements

Consolidated statement of cash flows

	Note	For the year ended 31 December 2019 USD'000	For the year ended 31 December 2018 USD'000
Cash flows from operating activities			
Profit for the year		**24,133**	48,182
Adjustments for:			
Depreciation and amortisation		**3,323**	3,206
Unwinding of discount on decommissioning liability		**877**	824
Impairment of goodwill		**9**	–
Share-based payment expense		**16,433**	–
		44,775	52,212
Decrease / (increase) in trade and other receivables		**6,724**	(9,807)
Increase in advance against decommissioning cost		**(3,286)**	(11,360)
Increase in inventories		**(663)**	(201)
Increase / (decrease) in trade and other payables		**24,950**	(784)
Cash generated from operations		**27,725**	30,060
Income taxes paid		**(29,894)**	(31,124)
Net cash flows from operating activities		**42,606**	(1,064)
Investing activities			
Purchases of property, plant and equipment		**(12,466)**	(4,037)
Net cash flows from investing activities		**(12,466)**	(4,037)
Financing activities			
Issue of ordinary shares		**1,182**	–
Proceeds from loans and borrowings		**12,917**	10,000
Repayment of loans and borrowings		**(7,059)**	(2,917)
Dividends paid to non-controlling interest		**(5,665)**	(2,125)
Dividends paid		**(11,550)**	–
Net cash (used in) / from financing activities		**(10,175)**	**4,958**
Net increase / (decrease) in cash and cash equivalents		**19,965**	(143)
Cash and cash equivalents at beginning of year		**7,926**	8,069
Cash and cash equivalents at end of year	14	**27,891**	7,926

The accompanying notes form part of these financial statements

Notes to the consolidated financial statements

1. Corporate information

The financial report of the Company and its subsidiaries (together the "Group") for the year ended 31 December 2019 was authorised for issue in accordance with a resolution of the Directors on 6 May 2020.

PetroNor E&P Limited is a 'for profit entity' and is a Company limited by shares incorporated in Australia. Its shares are publicly traded on the Oslo Axess (code: PNOR), a regulated marketplace of the Oslo Stock Exchange, Norway. The principal activities of the Group are the exploration and production of crude oil.

On 12 September 2019, the Company changed its name from African Petroleum Corporation Limited to PetroNor E&P Limited.

2. Basis of preparation

The financial report is a general-purpose financial report, which has been prepared in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report has been prepared on a historical cost basis.

The financial report is presented in United States Dollars, which is also the functional currency for the Company and all material subsidiaries, and all values are rounded to the thousand dollars unless otherwise stated.

The financial report is presented as a continuance of the activities of the Cypriot company PetroNor E&P Ltd, using the reverse acquisition rules for the merger that took place on 30 August 2019, Notes 4 & 23.

Compliance statement

The financial report complies with Australian Accounting Standards. The financial report also complies with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

Going concern

The underlying business of the Group created a net profit after tax of USD 13.6 million for 2019, whereas accounting-wise the Group incurred a net loss after tax of USD 5.76 million, due to recognising the extraordinary USD 19.37 million share-based payment expense for the reverse acquisition transaction. As at 31 December 2019, the Group's current assets exceeded its current liabilities by USD 8.4 million and had unrestricted cash of USD 27 million.

Since the end of the financial year, the COVID-19 outbreak is a globally significant event impacting the health of individuals, international trade and commerce and, as a result had a negative impact on global financial markets. Consequently, this has adversely affected the Group's business and its ability to operate efficiently. During March 2020, Governments of all the countries in which the Group operates closed borders to international travellers and introduced social distancing measures.

Additionally, since the end of the financial year, global oil prices have collapsed with the price of Brent crude falling from a level of USD 60 - 70 per barrel to a current level of around USD 30 per barrel and oil prices may be depressed throughout 2020. However, for 2021, market forecasters are predicting a significant recovery in oil price which is reflected in a contango on forward oil prices today, however as at the date of this report, it is uncertain what the effect will be on the Group moving forward.

These conditions indicate a material uncertainty that may cast a significant doubt about the entity's ability to continue as a going concern and, therefore, that it may be unable to realise its assets and discharge its liabilities in the normal course of business. This financial report has been prepared on the going concern basis which assumes the continuity of normal business activity and the realisation of assets and the settlement of liabilities in the normal course of business.

The Group has already implemented multiple cost saving measures, including streamlining of the organisation, initiating a simplification of the group structure and salary reductions as detailed in Note 24b and will continue to manage its activities with the objective of ensuring that it has sufficient cash reserves to meet its revised budgeted expenditures for the next twelve months from the date of this report.

2. Basis of preparation continued

As at the signing date of this report:

- outstanding amounts due to related parties Petromal LLC and NOR Energy AS for the cash consideration of the reverse transaction include USD 2.0 million and USD 3.6 million respectively; and
- the Group has been able to secure a refinancing for the loan payable to Rasmala of USD 12 million, (Note 19).

There are material uncertainties on the going concern status of the Group, due to the current challenging market conditions for the oil and gas industry as well as those created by the COVID-19 pandemic, the uncertain impact of these factors on the Group's operations, and the material uncertainty related to the Group's ability to renegotiate the terms of outstanding liabilities to related parties due for immediate repayment.

In the opinion of the Directors, the Group will be in a position to continue to meet its liabilities and obligations for a period of at least twelve months from the date of signing this report, having regard to the initiatives already underway and the expectation that the Group will be able to implement further financing strategies and commercial plans to be able to secure and execute its planned activities over the same period.

If the Group is not successful in executing these initiatives and / or in renegotiating the terms of outstanding liabilities to related parties, it may be unable to realise its assets and discharge its liabilities in the normal course of business and at the amounts stated in the financial report.

This financial report does not include any adjustments relating to the recoverability and classification of recorded asset amounts or to the amounts and classification of liabilities that might be necessary should the Group not continue as a going concern.

3. Summary of accounting policies

Accounting policies are selected and applied in a manner which ensures that the resulting financial information satisfies the concepts of relevance and reliability, thereby ensuring that the substance of the underlying transactions or other events is reported.

The following is a summary of the material accounting policies adopted by the Group in the preparation of the financial report. The accounting policies have been consistently applied, unless otherwise stated.

3a. Adoption of new and revised accounting standards

In the current period, the Group has adopted all of the new and revised Standards and Interpretations issued by the Australian Accounting Standards Board (the 'AASB') that are relevant to its operations and effective for reporting periods beginning on 1 January 2019. The Group has not elected to early adopt any new standards or amendments.

The Directors note that the impact of the initial application of the Standards and Interpretation is not yet known or is not reasonably estimable and is currently being assessed. At the date of authorisation of the financial statements, the Standards and Interpretations that were issued but not yet effective are listed below.

Standard/Interpretation	Effective
AASB 2019-1 Amendments to Australian Accounting Standards – Reference to the Conceptual Frameworks	1 Jan 2020
AASB 2018-6 Amendments to Australian Accounting Standards – Definition of a Business	1 Jan 2020
AASB 2018-7 Amendments to Australian Accounting Standards – Definition of Material	1 Jan 2020
AASB 2019-2 Amendments to Australian Accounting Standards – Implementation of AASB 1059	1 Jan 2020
AASB 2019-3 Amendments to Australian Accounting Standards – Interest Rate Benchmark Reform	1 Jan 2020
AASB 2019-5 Amendments to Australian Accounting Standards – Disclosure of the Effect of New IFRS Standards Not Yet Issued in Australia	1 Jan 2020
AASB 17 Insurance Contracts	1 Jan 2021
AASB 2014-10 Amendments to Australian Accounting Standards – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture	1 Jan 2022

At the date of authorisation of the financial statements, the following IASB Standards and IFRIC Interpretations were also in issue but not yet effective, although Australian equivalent Standards and Interpretations have not yet been issued.

None

3b. Consolidation

The consolidated financial statements comprise the financial statements of PetroNor E&P Limited ("the Company") and its subsidiaries for the year ended 31 December 2019 (together the Group).

Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:

- Power over the investee (ie existing rights that give it the current ability to direct the relevant activities of the investee)
- Exposure, or rights, to variable returns from its involvement with the investee, and
- The ability to use its power over the investee to affect its returns

When the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:

- The contractual arrangement with the other vote holders of the investee
- Rights arising from other contractual arrangements
- The Group's voting rights and potential voting rights

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the statement of comprehensive income from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income (OCI) are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:

- Derecognises the assets (including goodwill) and liabilities of the subsidiary
- Derecognises the carrying amount of any non-controlling interests
- Derecognises the cumulative translation differences recorded in equity
- Recognises the fair value of the consideration received
- Recognises the fair value of any investment retained
- Recognises any surplus or deficit in profit or loss
- Reclassifies the parent's share of components previously recognised in OCI to profit or loss or retained earnings, as appropriate, as would be required if the Group had directly disposed of the related assets or liabilities.

3c. Segment reporting

An operating segment is a component of an entity that engages in business activities from which it may earn revenues and incur expenses (including revenues and expenses relating to transactions with other components of the same entity), whose operating results are regularly reviewed by the entity's chief operating decision-makers to make decisions about resources to be allocated to the segments and assess their performance and for which discrete financial information is available. This includes start-up operations which are yet to earn revenues.

Operating segments have been identified based on the information available to chief operating decision-makers – being the Board and the executive management team.

Operating segments that meet the quantitative criteria as prescribed by AASB 8 are reported separately. However, an operating segment that does not meet the quantitative criteria is still reported separately where information about the segment would be useful to users of the financial statements.

Information about other business activities and operating segments that are below the quantitative criteria are combined and disclosed in a separate category called "all other segments".

3. **Summary of accounting policies** continued

3d. Foreign currency translation

Functional and presentation currency

The Company has elected to use United States Dollars, being the functional currency of all major subsidiaries in the Group, as its presentation currency. Where the functional currencies of entities within the consolidated group differ from United States Dollars, they have been translated into United States Dollars. The functional currency of PetroNor E&P Limited is United States Dollars.

Transactions and balances

Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the rate of exchange ruling at the reporting date and any gains or losses are recognised in the income statement.

Non-monetary items that are measured in terms of historical cost in the foreign currency are translated using the exchange rate as at the date of the initial transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined.

Translation of Group Companies' functional currency to presentation currency

On consolidation, the assets and liabilities of foreign operations are translated into United States Dollars at the rate of exchange prevailing at the reporting date and their income and expenditure are translated at exchange rates prevailing at the dates of the transactions. The exchange differences arising on translation for consolidation are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

3e. Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held at call with banks, other short-term highly liquid investments with original maturities of three months or less, and bank overdrafts. Bank overdrafts are shown within short-term borrowings in current liabilities on the Statement of Financial Position.

3f. Trade receivables

Trade receivables are amounts due from customers for goods sold or services performed in the ordinary course of business. They are generally due for settlement within 30 to 90 days and therefore are all classified as current. Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value. The group holds the trade receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

Trade receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the group, and a failure to make contractual payments for a period of greater than 120 days past due.

Impairment losses on trade receivables and contract assets are presented as net impairment losses within operating profit. Subsequent recoveries of amounts previously written off are credited against the same line item.

3g. Inventory

The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realisable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses. The cost of inventory includes all costs related to bringing the inventory to its current condition, including processing costs, labour costs, supplies, direct and allocated indirect operating overhead and depreciation expense, where applicable, including allocation of fixed and variable costs to inventory.

3h. Property plant and equipment

Oil & gas production assets

Oil and gas production assets are aggregated exploration and evaluation tangible assets and development expenditures associated with the production of proved reserves.

The cost of development and production assets also includes the cost of acquisitions and purchases of such assets, directly attributable overheads and the cost of recognising provisions for future restoration and decommissioning.

Where major and identifiable parts of the production assets have different useful lives, they are accounted for as separate items of property, plant and equipment. Costs of minor repairs and maintenance are expensed as incurred.

Depreciation

Oil and gas properties are depreciated using the unit-of-production method. Unit-of production rates are based on 1P proved reserves, which are oil, gas and other mineral reserves estimated to be recovered from existing facilities using current operating methods. Oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the field storage tank.

Field infrastructure exceeding beyond the life of the field is depreciated over the useful life of the infrastructure using a straight-line method.

Property, plant and equipment not associated with exploration and production activities are carried at cost less accumulated depreciation. These assets are also evaluated for impairment. Depreciation of other assets is calculated on a straight-line basis as follows:

Computer equipment	20 – 33.33%
Furniture, fixtures & fittings	10 – 33.33%
Motor vehicles	20%

3i. Exploration and evaluation expenditure

Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. For each area of interest, expenditure incurred in the acquisition of rights to explore and all costs directly associated with holding the licence such as rental, training and corporate and social responsibility are capitalised as exploration and evaluation intangible assets. Signature bonuses required by licence agreements are capitalised as exploration and evaluation intangible assets. Other costs directly associated with the licence are expensed as incurred.

Exploration, evaluation and development expenditure is recorded at historical cost and allocated to cost pools on an area of interest. Expenditure on an area of interest is capitalised and carried forward where rights to tenure of the area of interest are current and:

it is expected to be recouped through successful development and exploitation of the area of interest or alternatively by its sale; or

exploration and evaluation activities are continuing in an area of interest but at reporting date have not yet reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves.

Accumulated costs in respect of areas of interest which are abandoned are written off in full against profit in the period in which the decision to abandon the area is made.

Projects are advanced to development status when it is expected that further expenditure can be recouped through sale or successful development and exploitation of the area of interest.

All capitalised costs are subject to commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the statement of profit or loss and other comprehensive income.

3. **Summary of accounting policies** continued

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties.

Proceeds from disposal or farm-out transactions of intangible exploration assets are used to reduce the carrying amount of the assets. When proceeds exceed the carrying amount, the difference is recognised as a gain. When the Group disposes of its full interests, gains or losses are recognised in accordance with the policy for recognising gains or losses on sale of plant, property and equipment.

3j. Borrowing costs

Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset are added to the cost of the asset during the period of time that is required to complete and prepare the asset for its intended use. Borrowing costs are capitalised to the extent that funds are borrowed specifically for the purpose of obtaining a qualifying asset. To the extent that funds are borrowed generally and used for the purpose of obtaining a qualifying asset, the amount of borrowing costs eligible for capitalisation is determined by applying a capitalisation rate to the expenditures on that asset. All other borrowing costs are expensed as incurred.

3k. Revenue

(i) Revenue from petroleum products

Revenue from the sale of crude oil is recognised when a customer obtains control (“sales” or “lifting” method), normally this is when title passes at point of delivery. Revenues from production of oil properties are recognised based on actual volumes lifted and sold to customers during the period. Under a production sharing contract, where the group is required to pay profit oil tax and royalties on production of crude oil, such payments are settled in kind (where the government lift the crude it is entitled to). The Group presents a gross-up of the profit oil tax as an income tax expense with a corresponding increase in oil and gas revenues and any associated royalties are included in the cost of sales.

The Group assesses whether it acts as a principal or agent in each of its revenue arrangements. The Group has concluded that in all sales transactions it acts as a principal.

(ii) Variable consideration

If the consideration in a contract includes a variable amount, the Group recognises this amount as revenue only to the extent that it is highly probable that a significant reversal will not occur in the future.

Interest

Interest revenue is recognised on a time-proportional basis using the effective interest method. This is a method of calculating the amortised cost of a financial asset and allocating the interest income over the relevant period using the effective interest rate, which is the rate that exactly discounts the estimated future cash receipts through the expected useful life of the financial asset to the net carrying amount of the financial asset.

3l. Leases

(i) Right-of-use assets

The Group recognises right-of-use assets at the commencement date of the lease (ie, the date the underlying asset is available for use). Right-of-use assets are measured at cost, less any accumulated depreciation and impairment losses, and adjusted for any remeasurement of lease liabilities. The cost of right-of-use assets includes the amount of lease liabilities recognised, initial direct costs incurred, and lease payments made at or before the commencement date less any lease incentives received. Unless the Group is reasonably certain to obtain ownership of the leased asset at the end of the lease term, the recognised right-of-use assets are depreciated on a straight-line basis over the shorter of its estimated useful life and the lease term. Right-of-use assets are subject to impairment.

(ii) Lease liabilities

At the commencement date of the lease, the Group recognises lease liabilities measured at the present value of lease payments to be made over the lease term. The lease payments include fixed payments (including in-substance fixed payments) less any lease incentives receivable, variable lease payments that depend on an index or a rate, and amounts expected to be paid under residual value guarantees. The lease payments also include the exercise price of a purchase option reasonably certain to be exercised by the Group and payments of penalties for terminating a lease, if the lease term reflects the Group exercising the option to terminate. The variable lease payments that do not depend on an index or a rate are recognised as an expense in the period on which the event or condition that triggers the payment occurs. In calculating the present value of lease payments, the Group uses the incremental borrowing rate at the lease commencement date if the interest rate implicit in the lease is not readily determinable. After the commencement date, the amount of lease liabilities is increased to reflect the accretion of interest and reduced for the lease payments made. In addition, the carrying amount of lease liabilities is remeasured if there is a modification, a change in the lease term, a change in the in-substance fixed lease payments or a change in the assessment to purchase the underlying asset.

3m. Taxes

The income tax expense or benefit for the period consists of two components: current and deferred tax.

The current income tax payable or recoverable is calculated using the tax rates and legislation that have been enacted or substantively enacted at year-end in each of the jurisdictions and includes any adjustments for taxes payable or recovery in respect of prior periods.

Deferred tax assets and liabilities are determined using the balance sheet liability method based on temporary differences between the carrying value of assets and liabilities for financial reporting purposes and their tax bases. In calculating the deferred tax assets and liabilities, the tax rates used are those that have been enacted or substantively enacted by year-end in each of the jurisdictions and that are expected to apply when the assets are recovered, or the liabilities are settled.

Revenue-based taxes

In addition to corporate income taxes, the Group's consolidated financial statements also include and recognise as income taxes, other types of taxes on net income such as certain revenue-based taxes.

Revenue-based taxes are accounted for under AASB 112 when they have the characteristics of an income tax. This is considered to be the case when they are imposed under government authority and the amount payable is based on taxable income — rather than physical quantities produced or as a percentage of revenue — after adjustment for temporary differences. For such arrangements, current and deferred tax is provided on the same basis as described above for other forms of taxation. Obligations arising from royalty arrangements and other types of taxes that do not satisfy these criteria are accrued and included in cost of sales. The revenue taxes, except royalty, payable by the Group are considered to meet the criteria to be treated as part of income taxes.

Production-sharing arrangements

According to the production-sharing arrangement (PSA) in certain licences, the share of the profit oil to which the Government is entitled in any calendar year in accordance with the PSA is deemed to include a portion representing the corporate income tax imposed upon and due by the Group. This amount will be paid directly by the government on behalf of the Group to the appropriate tax authorities.

The income tax expense

The current income tax is calculated using the PSA, paid in barrels and booked as income tax and also shown as revenue.

Sales tax

Revenues, expenses and assets are recognised net of the amount of sales tax except:

Where the sales tax incurred on a purchase of assets or services is not recoverable from the taxation authority, in which case, the sales tax is recognised as part of the cost of acquisition of the asset or as part of the expense item as applicable.

Receivables and payables that are stated with the amount of sales tax included.

3. Summary of accounting policies continued

The net amount of sales tax recoverable from, or payable to, the taxation authority is included as part of receivables or payables in the statement of financial position.

Current and deferred tax balances attributable to amounts recognised directly in equity are also recognised directly in equity.

3n. Employee benefits

Provision is made for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required, and they are capable of being measured reliably. Provisions made in respect of employee benefits expected to be settled within 12 months are measured at their nominal values using the remuneration rate expected to apply at the time of settlement. Provisions made in respect of employee benefits, which are not due to be settled within 12 months are determined using the projected unit credit method.

3o. Trade and other payables

Trade and other payables are carried at amortised cost and due to their short-term nature, they are not discounted.

3p. Provisions

i. General

Provisions are recognised when the Group has a present obligation (legal or constructive) as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where the Group expects some or all of the provision to be reimbursed, for example under an insurance contract, the reimbursement is recognised as a separate asset but only when the reimbursement is virtually certain. The expense relating to any provision is recognised through profit and loss net of any reimbursement. If the effect of the time value of money is material, provisions are discounted using a current pre-tax rate that reflects, where appropriate, the risks specific to the liability. Where discounting is used, the increase in the provision due to the passage of time is recognised as interest expense. The present obligation under onerous contracts is recognised as a provision.

ii. Decommissioning liability

A decommissioning liability is recognised when the Group has a present legal or constructive obligation as a result of past events, and it is probable that an outflow of resources will be required to settle the obligation, and a reliable estimate of the amount of obligation can be made. A corresponding amount equivalent to the obligation is also recognised as part of the cost of the related production plant and equipment. The amount recognised in the estimated cost of decommissioning, discounted to its present value. Changes in the estimated timing of decommissioning or decommissioning cost estimates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to production plant and equipment. The unwinding of the discount on the decommissioning liability is included as a finance cost.

An escrow account is maintained by the operator of the licence and is governed by a joint operating agreement and the Congolese Government rules. The Group's share, paid against the decommissioning liability until the balance sheet date, is classified as an advance against decommissioning liability in current assets.

3q. Share capital

Contributed equity is recognised at the fair value of the consideration received by the Group, less any capital raising costs in relation to the issue.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

3r. Dividend distribution

Dividend distribution to the Company's shareholders is recognised as a liability in the Group's financial statements in the period in which the dividends are declared and appropriately authorised or approved by the Company's Shareholders' General Meeting. Interim dividends proposed by the Board of Directors are recognised as liabilities upon declaration.

3s. Share-based payments

The fair value of shares awarded is measured at the share price on the date the shares are granted. For options awarded, the fair value is measured at grant date using the Black-Scholes model. Shares and options which are subject to vesting conditions, are recognised over the estimated vesting period during which the holder becomes unconditionally entitled to the shares or options.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms had not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction; or is otherwise beneficial to the employee as measured at the date of modification.

3t. Financial instruments

A financial instrument is any contract that gives rise to a financial asset of any one entity and a financial liability or equity instrument of another entity.

i) Financial assets

Financial assets are classified, at initial recognition, as subsequently measured at amortised cost, fair value through other comprehensive income (OCI), and fair value through profit or loss, as appropriate.

The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Group's business model for managing them. With the exception of trade receivables that do not contain a significant financing component or for which the Group has applied the practical expedient, the Group initially measures a financial asset at its fair value plus, in the case of financial assets not subsequently measured at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.

In order for a financial asset to be classified and measured at amortised cost or fair value through OCI, it needs to give rise to cash flows that are solely payments of principal and interest (SPPI) on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level.

The Group's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both.

Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the marketplace (regular way trades) are recognised on the trade date, i.e., the date that the Group commits to purchase or sell the asset.

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognises financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a third party. This includes the derecognition of receivables for which discounting arrangements are entered into. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Subsequent measurement

For purposes of subsequent measurement, financial assets are classified in 4 categories:

- Financial assets at amortised cost (debt instruments)
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments)
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments)
- Financial assets at fair value through profit or loss

The Group has not designated any financial assets at fair value through profit or loss.

3. Summary of accounting policies continued

Financial assets at amortised cost (debt instruments)

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding;

Financial assets at amortised cost are subsequently measured using the effective interest (EIR) method and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

Cash equivalents

Cash equivalents are short-term, highly-liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and generally have a maturity of three months or less from the date of acquisition. Cash equivalents are classified as financial assets measured at amortised cost.

Loans granted

Loans granted that have fixed or determinable payments that are not quoted in an active market are classified as financial assets at amortised cost and are measured at amortised cost using the effective interest method, less any impairment. Interest income is recognised by applying the effective interest rate.

Loans granted to related parties are normally interest-free and do not have a fixed repayment structure. These loans are classified as financial assets at amortised cost and are measured at amortised cost using the effective interest method, less any impairment. Effective interest rate being zero in this case.

Derecognition

A financial asset (or, where applicable, a part of a financial asset or part of a group of similar financial assets) is primarily derecognised (ie, removed from the Group's consolidated statement of financial position) when:

The rights to receive cash flows from the asset have expired or the Group has transferred its rights to receive cash flows from the asset or has assumed an obligation to pay the received cash flows in full without material delay to a third party under a 'pass-through' arrangement; and either (a) the Group has transferred substantially all the risks and rewards of the asset, or (b) the Group has neither transferred nor retained substantially all the risks and rewards of the asset, but has transferred control of the asset.

When the Group has transferred its rights to receive cash flows from an asset or has entered into a pass-through arrangement, it evaluates if, and to what extent, it has retained the risks and rewards of ownership. When it has neither transferred nor retained substantially all of the risks and rewards of the asset, nor transferred control of the asset, the Group continues to recognise the transferred asset to the extent of its continuing involvement. In that case, the Group also recognises an associated liability. The transferred asset and the associated liability are measured on a basis that reflects the rights and obligations that the Group has retained.

Impairment of financial assets

The Group recognises an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms.

ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Group applies a simplified approach in calculating ECLs. Therefore, the Group does not track changes in credit risk, but instead recognises a loss allowance based on lifetime ECLs at each reporting date. The Group has established a provision matrix that is based on its historical credit-loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

The Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Group may also consider a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

ii) Financial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables, loans and borrowings, including bank overdrafts, financial guarantee contracts, and derivative financial instruments.

Subsequent measurement

The measurement of financial liabilities depends on their classification, as described below:

Financial liabilities at fair value through profit or loss.

Financial liabilities at fair value through profit or loss include derivative financial liabilities, financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Group that are not designated as hedging instruments in hedge relationships as defined by AASB 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognised in the statement of profit or loss.

Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in AASB 9 are satisfied.

Loans and borrowings

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest rate ("EIR") method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in the statement of profit or loss.

This category generally applies to interest-bearing loans and borrowings.

3. Summary of accounting policies continued

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

iii) Offsetting of financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated statement of financial position if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis, to realise the assets and settle the liabilities simultaneously.

3u. Joint arrangements

Joint arrangements are arrangements of which two or more parties have joint control. Joint control is the contractual agreed sharing of control of the arrangement which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control. Joint arrangements are classified as either a joint operation or joint venture, based on the rights and obligations arising from the contractual obligations between the parties to the arrangement.

To the extent the joint arrangement provides the Company with rights to the individual assets and obligations arising from the joint arrangement, the arrangement is classified as a joint operation and as such, the Company recognises its:

- Assets, including its share of any assets held jointly;
- Liabilities, including its share of any liabilities incurred jointly;
- Revenue from the sale of its share of the output arising from the joint operation;
- Share of revenue from the sale of the output by the joint operation; and
- Expenses, including its share of any expenses incurred jointly.

To the extent the joint arrangement provides the Company with rights to the net assets of the arrangement, the investment is classified as a joint venture and accounted for using the equity method. Under the equity method, the cost of the investment is adjusted by the post-acquisition changes in the Company's share of the net assets of the venture.

3v. Current versus non-current classification

The Group presents assets and liabilities in the statement of financial position based on current/non-current classification. An asset is current when it is either:

- Expected to be realised or intended to be sold or consumed in the normal operating cycle;
- Held primarily for the purpose of trading;
- Expected to be realised within 12 months after the reporting period;
- Cash or cash equivalent unless restricted from being exchanged or used to settle a liability for at least 12 months after the reporting period.

All other assets are classified as non-current.

A liability is current when either:

- It is expected to be settled in the normal operating cycle
- It is held primarily for the purpose of trading
- It is due to be settled within 12 months after the reporting period
- There is no unconditional right to defer the settlement of the liability for at least 12 months after the reporting period

The Group classifies all other liabilities as non-current.

Deferred tax assets and liabilities are classified as non-current assets and liabilities.

3w. Business combinations and goodwill

In order to consider an acquisition as a business combination, the acquired asset or groups of assets must constitute a business (an integrated set of operations and assets conducted and managed for the purpose of providing a return to the investors). The combination consists of inputs and processes applied to these inputs that have the ability to create output. Acquired businesses are included in the financial statements from the transaction date. The transaction date is defined as the date on which the company achieves control over the financial and operating assets. This date may differ from the actual date on which the assets are transferred. Comparative figures are not adjusted for acquired, sold or liquidated businesses. On acquisition of a licence that involves the right to explore for and produce petroleum resources, it is considered in each case whether the acquisition should be treated as a business combination or an asset purchase. Generally, purchases of licences in a development or production phase will be regarded as a business combination. Business combinations are accounted for using the acquisition method. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition date fair value and the amount of any non-controlling interest (NCI) in the acquiree. For each business combination, the Group elects whether to measure NCI in the acquiree at fair value or at the proportionate share of the acquiree's identifiable net assets. Acquisition related costs are expensed as incurred and included in administrative expenses.

When the Group acquires a business, it assesses the assets and liabilities assumed for appropriate classification and designation in accordance with the contractual terms, economic circumstances and pertinent conditions as at the acquisition date. This includes the separation of embedded derivatives in host contracts by the acquiree. Those acquired petroleum reserves and resources that can be reliably measured are recognised separately in the assessment of fair values on acquisition. Other potential reserves, resources and rights, for which fair values cannot be reliably measured, are not recognised separately, but instead are subsumed in goodwill.

Any contingent consideration to be transferred by the acquirer will be recognised at fair value at the acquisition date. Contingent consideration classified as an asset or liability that is a financial instrument and within the scope of AASB 9 Financial Instruments: Recognition and Measurement is measured at fair value, with changes in fair value recognised either in the statement of profit or loss or as a change to other comprehensive income. If the contingent consideration is not within the scope of AASB 9, it is measured in accordance with the appropriate AASB. Contingent consideration that is classified as equity is not remeasured, and subsequent settlement is accounted for within equity.

Goodwill is initially measured at cost, being the excess of the aggregate of the consideration transferred and the amount recognised for NCI over the fair value of the identifiable net assets acquired and liabilities assumed. If the fair value of the identifiable net assets acquired is in excess of the aggregate consideration transferred (bargain purchase), before recognising a gain, the Group reassesses whether it has correctly identified all of the assets acquired and all of the liabilities assumed and reviews the procedures used to measure the amounts to be recognised at the acquisition date. If the reassessment still results in an excess of the fair value of net assets acquired over the aggregate consideration transferred, then the gain is recognised in the statement of profit or loss and other comprehensive income.

After initial recognition, goodwill is measured at cost less any accumulated impairment losses. For the purpose of impairment testing, goodwill acquired in a business combination is, from the acquisition date, allocated to each of the Group's cash generating units (CGUs) that are expected to benefit from the combination, irrespective of whether other assets or liabilities of the acquiree are assigned to those units.

Where goodwill forms part of a CGU and part of the operation in that unit is disposed of, the goodwill associated with the disposed operation is included in the carrying amount of the operation when determining the gain or loss on disposal.

Goodwill disposed of in these circumstances is measured based on the relative values of the disposed operation and the portion of the CGU retained.

4. Significant accounting judgements, estimates and assumptions

The Directors evaluate estimates and judgements incorporated in the Financial Report based on historical knowledge and best-available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data, obtained both externally and within the Group.

Management has identified the following critical accounting policies for which significant judgements, estimates and assumptions are made. Actual results may differ from these estimates under different assumptions and conditions and may materially affect financial results or the financial position reported in future period.

Further details of the nature of these assumptions and conditions may be found in the relevant notes to the financial statements.

4. Significant accounting judgements, estimates and assumptions continued

Hydrocarbon reserve and resource estimates

Hydrocarbon reserves are estimates of the amount of hydrocarbons that can be economically and legally extracted from the Group's oil and gas properties. The Group estimates its commercial reserves and resources based on information compiled by appropriately-qualified persons relating to the geological and technical data on the size, depth, shape and grade of the hydrocarbon body and suitable production techniques and recovery rates. Commercial reserves are determined using estimates of oil and gas in place, recovery factors and future commodity prices, the latter having an impact on the total amount of recoverable reserves and the proportion of the gross reserves which are attributable to the host government under the terms of the Production-Sharing Agreements. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities, and other capital costs. The current long-term Brent oil price assumption used in the estimation of commercial reserves is USD 55/bbl. The carrying amount of oil and gas properties at 31 December 2019 is shown in Note 16.

The Group estimates and reports hydrocarbon reserves in line with the principles contained in the Society of Petroleum Engineers (SPE) Petroleum Resources Management Reporting System (PRMS) framework. As the economic assumptions used may change and as additional geological information is obtained during the operation of a field, estimates of recoverable reserves may change. Such changes may impact the Group's reported financial position and results, which include:

- The carrying value of oil and gas properties may be affected due to changes in estimated future cash flows (Note 16);
- Depreciation and amortisation charges in the statement of profit or loss and other comprehensive income may change where such charges are determined using the UOP method, or where the useful life of the related assets change (Note 16);
- Provisions for decommissioning may require revision — where changes to reserves estimates affect expectations about when such activities will occur and the associated cost of these activities (Note 20).

Taxes

The Group operates in several tax jurisdictions, and consequently, its income is subject to various rates and rules of taxation. As a result, the Company's effective tax rate may vary significantly depending upon the profitability of operations in the different jurisdictions.

The Group recognises the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires the Group to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction, to the extent that future cash flows and taxable income differ significantly from estimates. The ability of the Group to realise the net deferred tax assets recorded at the date of the statement of financial position could be impacted.

Additionally, future changes in tax laws in the jurisdictions in which the Group operates could limit the ability of the Group to obtain tax deductions in future periods.

Additional information on the accounting policy for taxes is explained further in Note 10.

Decommissioning costs

Decommissioning costs will be incurred by the Group at the end of the operating life of some of the Group's facilities and properties. The Group assesses its retirement obligation at each reporting date. The ultimate decommissioning costs are uncertain and cost estimates can vary in response to many factors, including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing, extent and amount of expenditure can also change, for example in response to changes in reserves or changes in laws and regulations or their interpretation. Therefore, significant estimates and assumptions are made in determining the provision for decommissioning costs. As a result, there could be significant adjustments to the provisions established which would affect future financial results. The provision at reporting date represents management's best estimate of the present value of the future decommissioning costs required.

Share-based payment – Costs of listing

The listed entity, PetroNor E&P Limited has not met the definition of a business for the reverse acquisition transaction, consequently no goodwill is allowed to be capitalised for the variance between the consideration paid and the fair value net assets on acquisition. Correspondingly, any excess-deemed acquisition costs must be accounted for as an expense in accordance with AASB 2 (Note 23a).

For most reverse takeover transactions of listed shell companies, there is minimal variance between the consideration paid and the fair value of the net assets acquired, and any associated share-based expense may not be significant.

Due to the ongoing arbitration matters in Senegal and The Gambia and the uncertainty over legal tenure, these exploration licences have no book value in the accounting records of the Company. This accounting treatment has meant there is a significant variance between the market value of the company as indicated by its publicly traded share price and the book net assets on completion of the transaction.

5. Revenue from contracts with customers

	2019 USD'000	2018 USD'000
Revenue from sales of petroleum products	**57,479**	54,687
Assignment of tax oil	**29,894**	31,124
Assignment of royalties	**15,387**	15,258
	102,760	101,069

Quantity of oil lifted (barrels)	**880,844**	812,000
Average selling price (USD per barrel)	**65.25**	67.35

All revenue from the sales of petroleum products is recognised and transferred at a point in time

6. Cost of sales

	2019 USD'000	2018 USD'000
Operating expenses	**18,292**	22,125
Royalty	**15,387**	15,258
Depreciation and amortisation of oil and gas properties	**3,231**	3,206
Closing oil inventory	**297**	988
	37,207	41,577

7. Other operating income

	2019 USD'000	2018 USD'000
Other	**9**	491

8. Administrative expenses

	Note	**2019 USD'000**	2018 USD'000
Employee benefit expenses		**4,035**	4,206
Travelling expenses		**1,047**	1,492
Business development expenses		**19**	1,794
Legal and professional expenses		**6.502**	1,651
Office rent		**214**	202
Related-party loan write-off	24	**5,305**	–
Other expenses		**2,671**	745
		19,793	10,090

8. Administrative expenses continued

8a. Employee benefit expenses

	2019 USD'000	2018 USD'000
Salaries	**3,331**	3,542
Short-term non-monetary benefits	**308**	347
Defined contribution pension cost	**75**	–
Share-based payment expense	**–**	–
Social-security contributions and similar taxes	**321**	317
	4,035	4,206

8b. Auditors' remuneration

	2019 USD'000	2018 USD'000
Paid or payable to BDO		
Audit review of financial reports		
BDO (WA) Pty Ltd	**40**	–
BDO related practices	**90**	–
	130	–
Other non-assurance services		
BDO related practices	**12**	–
	142	–
Paid or payable to other audit firms		
Audit or review of financial reports	**138**	125
Other non-assurance services	**141**	–
	279	125

Fees, excluding VAT, to the auditors are included in administration expenses.

9. Finance cost

	Note	2019 USD'000	2018 USD'000
Unwinding of discount on decommissioning liability	20	**877**	824
Loan structuring fee		**105**	100
Interest on loan	19	**839**	599
		1,822	1,623

10. Tax expense

	2019 USD'000	2018 USD'000
Petroleum revenue tax expense		
Current income tax charge	**29,894**	31,124
Total tax expense reported in the consolidated statement of comprehensive income	**29,894**	31,124

The income tax expense is only related to the subsidiary in Congo and represents the assignment of tax oil on the revenue from sales of petroleum products, Note 5. There was no income tax expense in the other subsidiaries' jurisdictions nor in the parent's jurisdiction as these companies are in taxable loss positions in both 2019 and 2018. Average effective tax rate for the year was 29% (2018: 31%) based on gross revenue of the Group.

Deferred tax assets have not been brought to account in respect of tax losses and unrecognised capital allowances because as at 31 December 2019 it is uncertain when future taxable amounts will be available to utilise those temporary differences and losses. As at 31 December 2019, the carried forward gross tax loss is USD 202 million (2018: USD 1.68 million).

11. Earnings per share

	2019 USD'000	2018 USD'000
(Loss) / Profit attributable to ordinary shareholders		
(Loss) / Profit from continuing operations attributable to the ordinary equity holders used in calculating basic loss per share	**(13,364)**	7,838
(Loss) / Profit attributable to the ordinary equity holders used in calculating basic loss per share	**(13,364)**	7,838

	Number of shares	Number of shares
Weighted average number of ordinary shares outstanding during the period used in the calculation of basic and diluted (loss) / profit per share	**1,140,087,271**	816,198,842

Options on issue are considered to be potential ordinary shares and have been included in the determination of diluted loss per share only to the extent to which they are dilutive. There are 3,266,470 options as at 31 December 2019 (2018: nil options). These options have not been included in the determination of basic loss per share because they are considered to be anti-dilutive.

12. Inventories

	2019 USD'000	2018 USD'000
Crude oil inventory	**871**	868
Materials and supplies	**2,362**	1,702
	3,233	2,570

The crude oil inventory and the material and supplies inventory are valued at the lower of cost and net realisable value. Cost is determined using the weighted average method. Net realisable value is the estimated selling price, less applicable selling expenses. The cost of inventory includes all costs related to bringing the inventory to its current condition, including processing costs, labour costs, supplies, direct and allocated indirect operating overhead and depreciation expense, where applicable, including allocation of fixed and variable costs to inventory.

13. Accounts receivable, deposits and prepayments

	Note	2019 USD'000	2018 USD'000
Trade receivables		**4,013**	3,391
Due from related parties	24	**5,639**	12,929
Advance against decommissioning cost[1]	20	**14,646**	11,360
Other receivables		**474**	530
		24,772	28,210

1. In addition to the booking of decommissioning cost asset and liability, the contractors group and the Congolese Government have decided to set up funds for the decommissioning cost in an escrow account which is managed by the operator. The advances of the funds for the year are made on the basis of an average rate of 3.50 USD per barrel produced (2018: 4.28 USD per barrel).

14. Cash and bank balances

	2019 USD'000	2018 USD'000
Cash in bank	**26,988**	7,924
Petty cash	**–**	2
Restricted cash	**903**	–
	27,891	7,926

Restricted cash balances represent cash-backed security provided in relation to the Company's obligations required under the exploration licences. The cash will be utilised for training and resources by mutual agreement with the relevant country's government authorities.

15. Segment information

For management purposes, the Group is organised into one main operating segment, which involves exploration and production of hydrocarbons. All of the Group's activities are interrelated, and discrete financial information is reported to Chief Operating Decision Maker as a single segment. Accordingly, all significant operating decisions are based upon analysis of the Group as one segment. The financial results from this segment are equivalent to the financial statements of the Group as a whole.

The Group only has one operating segment, being exploration and production of hydrocarbons.

The analysis of the location of non-current assets is as follows:

	2019 USD'000	2018 USD'000
Congo	**27,182**	18,145
The Gambia	**–**	–
Nigeria	**–**	–
Norway	**83**	–
Senegal	**2**	–
UK	**11**	–
	27,278	18,145

16. Production assets and equipment

2019	**Production assets and equipment USD'000**	**Motor vehicles USD'000**	**Total USD'000**
Cost			
At 1 January 2019	**16,455**	**9**	**16,464**
Additions	**12,375**	**–**	**12,375**
Disposals	**–**	**(9)**	**(9)**
At 31 December 2019	**28,830**	**–**	**28,830**
Depreciation			
At 1 January 2019	**3,875**	**9**	**3,884**
Charge for the year	**2,368**	**–**	**2,368**
Depreciation on disposals	**–**	**(9)**	**(9)**
At 31 December 2019	**6,243**	**–**	**6,243**
Net carrying amount			
At 31 December 2019	**22,587**	**–**	**22,587**

2018	Production assets and equipment USD'000	Motor vehicles USD'000	Total USD'000
Cost			
At 1 January 2018	12,425	9	12,434
Additions	4,030	–	4,030
At 31 December 2018	16,455	9	16,464
Depreciation			
At 1 January 2018	1,571	9	1,580
Charge for the year	2,304	–	2,304
At 31 December 2018	3,875	9	3,884
Net carrying amount			
At 31 December 2018	12,580	–	12,580

Production assets and equipment cost includes the following:

	Note	2019 USD'000	2018 USD'000
Decommissioning costs	20	**11,899**	11,899
Oil & gas CAPEX		**16,819**	4,556
		28,718	16,455

17. Intangible assets

Net carrying value	Note	2019 USD'000	2018 USD'000
Licences and approval	17i	**4,686**	5,549
Software	17ii	**5**	7
Goodwill		**–**	9
		4,691	5,565

i) Licences and approval

	2019 USD'000	2018 USD'000
Cost		
At 1 January	**7,382**	7,382
Addition	**–**	–
At 31 December	**7,382**	7,382
Accumulated amortisation and impairment		
At 1 January	**1,833**	931
Amortisation	**863**	902
Impairment	**–**	–
At 31 December	**2,696**	1,833
Net carrying value		
At 1 January	**5,549**	6,451
At 31 December	**4,686**	5,549

Licence overview and risk

The Group's exploration and production assets relate to the following licences:

Country	Licence	Carrying value as at 31 December 2019 / USD 000,000	Operator	Working Interest	Area km^2
Congo	PNGF Sud	**5.5**	Perenco	20%	482.28
Senegal	Rufisque Offshore Profond	**–**	African Petroleum Senegal Limited	90%	10,357
Senegal	Senegal Offshore Sud Profond	**–**	African Petroleum Senegal Limited	90%	5,439
The Gambia	A1	**–**	African Petroleum Gambia Limited	100%	1,296
The Gambia	A4	**–**	African Petroleum Gambia Limited	100%	1,376

Congo

In 2017, subsidiary company Hemla E&P Congo SA acquired interest in three development and production permits (Tchendo: 20%; Tchibouela: 20% and Tchibeli-Litanzi: 20%) which will respectively end in December 2037 for each of them with possible extension for 5 years. All these three licenses are called or named collectively "PNGF Sud".

17. Intangible assets continued

Senegal

As at the date of this report, the Company's subsidiary African Petroleum Senegal Limited had registered a request for arbitration proceedings with the International Centre for the Settlement of Investment Disputes (ICSID) to protect its interests in the Senegal Offshore Sud Profond and Rufisque Offshore Profond blocks in Senegal (ICSID case ARB/18/24).

The Gambia

As at the date of this report, the Company's subsidiary African Petroleum Gambia Limited had initiated arbitration proceedings at the ICSID to protect its interests in the A1 and A4 licences in The Gambia (ICSID case ARB/17/38).

Reserves

The Group has adopted a policy of regional reserve reporting using external third-party companies to audit its work and certify reserves and resources. Reserve and contingent resource estimates comply with the definitions set by the Petroleum Resources Management System ("PRMS") issued by the Society of Petroleum Engineers ("SPE"), the American Association of Petroleum Geologists ("AAPG"), the World Petroleum Council ("WPC") and the Society of Petroleum Evaluation Engineers ("SPEE") in March 2007. The Group uses the services of AGR Petroleum Services AS for 3rd party verifications of its reserves.

The following is a summary of key results from the reserve reports (net of the Group's share):

Asset	1P reserves MMbbls	2P reserves MMbbls	3P reserves MMbbls
PNGF Sud	7.02	10.76	14.04

Definitions:

1P) Proved Reserves

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations.

2P) Proved plus Probable Reserves

Probable Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

3P) Proved plus Probable plus Possible Reserves

Possible Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Probable Reserves.

ii) Software

	2019 USD'000	2018 USD'000
Cost		
At 1 January	**7**	–
Addition	**–**	7
At 31 December	**7**	7
Accumulated amortisation and impairment		
At 1 January	**–**	–
Amortisation	**2**	–
Impairment	**–**	–
At 31 December	**2**	–
Net carrying value		
At 1 January	**7**	–
At 31 December	**5**	7

18. Accounts payable and accrued liabilities

	Note	2019 USD'000	2018 USD'000
Trade payables		**14,809**	3,787
Due to related parties	24	**13,784**	2,138
Taxes and state payables		**473**	313
Other payables and accrued liabilities		**5,536**	3,415
		34,602	9,653

19. Loans payable

	2019 USD'000	2018 USD'000
At 1 January	**7,083**	–
Received	**12,917**	10,000
Principal repayment	**(7,059)**	(2,917)
Interest on loan accrued	**822**	699
Interest on loan paid	**(822)**	(699)
At 31 December	**12,941**	7,083

Ageing of loans payable	2019 USD'000	2018 USD'000
Current	**12,941**	5,000
Non-current	**–**	2,083
	12,941	7,083

During the year, the company renegotiated the terms of an existing loan from a third party Rasmala (Dubai-based investor group). The loan is repaid in monthly instalments and carries an interest rate of 10% plus one-month LIBOR payable monthly. The loan is secured against the assignment of receivables by subsidiary company Hemla Africa Holding AS and a corporate guarantee from significant shareholder Petromal – Sole Proprietorship LLC.

20. Decommissioning liability

In accordance with the agreements and legislation, the wellheads, production assets, pipelines and other installations may have to be dismantled and removed from oil and natural gas fields when the production ceases. The exact timing of the obligations is uncertain and depends on the rate the reserves of the field are depleted. However, based on the existing production profile of the PNGF Sud field and the size of the reserves, it is expected that expenditure on retirement is likely to be after more than ten years. The current bases for the provision are a discount rate of 6.5% and an inflation rate of 1.6%. The decommissioning liability (ARO) study was done internally by the operator Perenco and was presented to ARO Committee. The partners approved the study on 13 November, 2018.

The following table presents a reconciliation of the beginning and ending aggregate amounts of the obligations associated with the retirement of oil and natural gas properties:

	2019 USD'000	2018 USD'000
At 1 January	**13,496**	12,672
Arising during the year	**–**	–
Unwinding of discount on decommissioning	**877**	824
At 31 December	**14,373**	13,496

21. Share capital

Ordinary shares participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held and in proportion to the amount paid up on the shares held.

At shareholders' meetings, each ordinary share entitles the holder to one vote in proportion to the paid-up amount of the share when a poll is called, otherwise each shareholder has one vote on a show of hands.

Reconciliation of movement in shares on issue

	Number of fully paid ordinary shares 2019
Balance of shares of Cypriot PetroNor E&P Ltd prior to merger	**100,000**
Balance of shares of Australian PetroNor E&P Limited prior to merger	**155,466,446**
Acquisition of Cypriot PetroNor E&P Ltd shares	**(100,000)**
Issue of shares for merger consideration[1]	**816,198,842**
Exercise of share options and warrants	**–**
Balance at end of the year	**971,665,288**

1. On 30 August 2019, the Company issued 816,199,842 shares at NOK 1.032 each

Cypriot company, PetroNor E&P Ltd had 100,000 ordinary shares as at the beginning and end of 2018, with no movements during the year.

Reconciliation of movements in issued capital

	2019 USD'000	2018 USD'000
Balance at beginning of the year		
Fair value of issued share capital at beginning of the year	**120**	120
Issue of shares for reverse takeover[1]	**17,615**	–
Exercise of share options	**–**	–
Share capital at end of the year	**17,735**	120

1. On 30 August 2019, the Company issued 816,199,842 shares at NOK 1.032 each

Capital Management

Management controls the capital of the Company in order to maximise the return to shareholders and ensure that the Company can fund its operations and continue as a going concern. Capital is defined as issued share capital.

Management effectively manages the Company's capital by assessing the Company's financial risks and adjusting its capital structure in response to changes in these risks and in the market. These responses include the management of expenditure and debt levels, distributions to shareholders and share and option issues. There have been no changes in the strategy adopted by management to control the capital of the Company since the prior reporting period.

Management monitors capital requirements through cash flow forecasting. Management may seek further capital if required through the issue of capital or changes in the capital structure. The Group has no externally imposed capital requirements.

22. Reserves

Share-based payment reserve

The share-based payments reserve records options and share awards recognised as expenses, issued to employees, directors and consultants.

Foreign currency translation reserve

The foreign currency translation reserve is used to recognise foreign currency exchange differences arising on translation of functional currency to presentation currency.

Retained earnings

All other net gains and losses and transactions with owners not recognised elsewhere.

23. Share-based payments

	2019 USD'000	2018 USD'000
Reverse acquisition – Costs of listing	**19,374**	–
Warrants	**–**	–
Options	**–**	–
Share based payment charge for the year	**19,374**	–

23a. Reverse acquisition – costs of listing

On 30 August 2019, the Company entered into a share purchase agreement with the Cypriot company PetroNor E&P Ltd. Consideration for 100% of the share capital of the Cypriot company comprised the following:

- 816,198,842 new shares issued at NOK 1.032 each;
- 155,466,446 warrants issued with a nil exercise price, vesting conditions and expiry date of 31 December 2019. The vesting conditions related to specific performance milestones including the signing of a binding gas offtake agreement for an asset in Nigeria; and
- USD 11,549,988 deferred cash consideration, payable and due upon the finalisation of the 2018 dividend from the operating subsidiary company Hemla E&P Congo SA.

Costs associated with the transaction totalled USD 2 million; and has been expensed as incurred by both sides. Therefore, only costs of USD 1.19M are included in the Statement of Comprehensive Income for the transaction, with the balance recognised as part of the retained losses of Australian PetroNor E&P Limited at the point of the merger.

The transaction has been considered a reverse takeover, but not a business combination. Although the Australian company PetroNor E&P Limited has licences in The Gambia and Senegal, with the ongoing arbitration matters there were no active operations, consequently the Company was considered a 'non-business' listed company.

The Cypriot company PetroNor E&P Ltd is considered the accounting acquirer and the Australian company PetroNor E&P Limited is the legal acquirer.

The acquisition is accounted for as a continuation of the financial statements of the Cypriot PetroNor E&P Ltd. The Transaction assessed fair value in excess of the net assets of Australian PetroNor E&P Limited, and an estimate for listing expenses has been expensed as a share-based payment in accordance with AASB 2.

The estimate for listing expenses is based on the deemed market capitalisation of the company:

		Number of shares[1]	Share value USD'000
Existing Australia PetroNor E&P Limited shareholders	16%	155,466,446	17,615
New issue to Cypriot PetroNor E&P Ltd shareholders	84%	816,198,842	92,479
Deemed market capitalisation of the Company	100%	971,665,288	98,544

1. Share price on completion date 30 August 2019, NOK 1.032 (equivalent USD 0.113)

	USD' 000
Implied issued capital for acquisition of Australian PetroNor E&P Limited	17,615
Add net book value of Australian PetroNor E&P Limited net liabilities acquired as at 30 August 2019	1,759
Share-based payment charge for the year	19,374

Accounting treatment of exploration assets only allows intangible asset values to be carried forward and not impaired, if the Company can demonstrate legal right of tenure. Due to the ongoing arbitration matters for the Senegalese and Gambian licences, there was uncertainty around the legal right of tenure for these licences. For this reason, the book carrying value of these assets is nil for the transaction. However, prior to completion of the reverse acquisition transaction the market capitalisation of Australian company PetroNor E&P Limited exceeded the book value of its net liabilities, therefore implying the Senegalese and Gambian licences had significant residual value, and supports the material share-based payment charge recognised for the transaction.

23. Share-based payments continued

23b. Warrants

During the current year, 8,513,848 unlisted warrants were issued to staff, Directors and consultants of the Company; these were subject to vesting conditions dependent on operational performance milestones related to the reinstatement of licences in The Gambia and Senegal.

During the current year, 310,932,892 unlisted warrants were issued to shareholders of the Company, these were subject to vesting conditions dependent on operational performance milestones either related to the reinstatement of licences in The Gambia and Senegal, or the signing of a binding gas offtake agreement for an asset in Nigeria.

None of these warrants vested before the expiry date of 31 December 2019, and consequently as at the year-end, there were no unlisted warrants outstanding (31 December 2018: nil). No expense was recognised within the Statement of Comprehensive Income for the issue of these warrants, as the warrants were subject to vesting conditions that did not occur; and were awarded and lapsed during the same period.

Grant date	Expiry date	Number of options	Expected life of options (years)	Risk free rate (%)	Volatility (%)	Dividend yield (%)	Exercise price NOK	Exercise price equivalent USD	Fair value at grant date NOK	Fair value at grant date USD
30 Aug 2019	31 Dec 2019	319,446,740	0.33	0.89	125	–	nil	nil	1.032	0.113

23c. Options

Holders of options do not have any voting or dividend rights in relation to the options.

The Company has used the Black-Scholes methodology for measuring the option pricing.

The following reconciles the outstanding share options granted, exercised and forfeited during the year:

	2019		2018	
	Number of options	**Weighted average exercise price equivalent USD[1]**	Number of options[1]	Weighted average exercise price equivalent USD[1]
Balance at beginning of the period	**–**	**–**	–	–
Awarded	**–**	**–**	–	–
Reverse takeover[2]	**3,283,137**	**0.53**	–	–
Lapsed	**(16,667)**	**2.10**	–	–
Forfeited during the year	**–**	**–**	–	–
Balance at end of the year	**3,266,470**	**0.53**	–	–
Exercisable at end of the year	**3,266,470**	**0.53**	–	–

1. The USD equivalent weighted average exercise price as at 31 December 2019
2. On August 2019, 3,283,137 options were recognised in relation to outstanding options awarded before the reverse acquisition transaction with PetroNor E&P Limited took place.

The value of options capitalised during the period was nil (2018: nil).

The share options outstanding at the end of the period had a weighted average remaining contractual life of 495 days (2018: nil days).

24. Related party transactions

24a. Subsidiaries

The principal subsidiaries of the PetroNor E&P Limited group, all of which have been included in these consolidated financial statements, are as follows:

Name	Country of incorporation	Principal place of business	Proportion of ownership interest at 31 December 2019	2018
PetroNor E&P Ltd	Cyprus	Cyprus	**100%**	100%
PetroNor E&P AS	Norway	Norway	**100%**	100%
PetroNor E&P Services Ltd[1]	United Kingdom	United Kingdom	**100%**	–
PetroNor E&P Nigeria Ltd	Nigeria	Nigeria	**100%**	–
Hemla Africa Holding AS	Norway	Norway	**70.707%**	70.707%
Hemla E&P Congo SA	Congo	Congo	**52.50%**	52.50%
African Petroleum Corporation Ltd[1]	Cayman Islands	United Kingdom	**100%**	–
African Petroleum Gambia Ltd[1]	Cayman Islands	The Gambia	**100%**	–
African Petroleum Senegal Ltd[1]	Cayman Islands	Senegal	**90%**	–
African Petroleum Senegal SAU[1]	Senegal	Senegal	**100%**	–
APCL Gambia BV [1]	Netherlands	The Gambia	**100%**	–

1. These entities merged into the group on the completion of the reverse takeover of African Petroleum Corporation Limited on 30 August 2019

Reverse takeover

On 30 August 2019, the Oslo Axess listed company PetroNor E&P Limited ("PNOR") (formerly called African Petroleum Corporation Limited) purchased the entire share capital of PetroNor E&P Ltd, a company registered in Cyprus. The consideration for the transaction comprised of the issue of 816,198,842 ordinary shares in PNOR, the issue of 155,466,446 warrants contingent on performance milestones in PNOR, and the deferred cash consideration of USD 11,549,988 to represent the share of the dividend payable for the year ended 31 December 2018 from operating subsidiary, Hemla E&P Congo SA.

Material non-controlling interests

	2019		2018	
	Hemla E&P Congo SA USD'000	**Hemla Africa Holding AS USD'000**	Hemla E&P Congo SA USD'000	Hemla Africa Holding AS USD'000
Non-current assets	**28,959**	**1,185**	18,135	1,188
Current assets	**38,106**	**26,291**	28,147	24,680
Non-current liabilities	**14,373**	**–**	13,496	2,083
Current liabilities	**20,911**	**13,092**	7,845	19,347
Revenue	**102,760**	**–**	101,069	59,496
Profit for the year	**27,430**	**9,950**	20,652	4,461
Total comprehensive income for the year	**27,430**	**9,950**	20,652	4,461
Profit attributable to non-controlling interest	**13,029**	**2,915**	9,810	1,307
Dividends distributed during the year	**22,000**	**–**	8,500	–

24b. Key management personnel remuneration

Key management personnel are those persons having authority and responsibility for planning, directing and controlling the activities of the Group, including the directors of the company listed on page 24, and the following other key personnel:

G Ludvigsen	Business Development Manager
C Frimann-Dahl	Chief Technical Officer
E Sultan	Strategy and Contracts Manager
M Barrett	Exploration Manager
C Butler	Group Financial Controller
A Hicks	Company Secretary

24. Related party transactions continued

Post year-end remuneration reductions

Following the restructure of the Board of Directors after the merger of the companies and also in response to the Covid-19 global pandemic, remuneration for key management was reconsidered to lower the cost base and strengthen the position of the Company during this crisis. As at the approval date of this report the reduced base salary and fees for the following members of key management is as follows:

Individual	Title	Group Entity	Salary and fees/ per annum	Total salary and fees USD equivalent USD
E Alhomouz	Chairman[1] Non-Executive Director	PetroNor E&P AS Hemla E&P Congo SA	USD 240,000 USD 120,000	360,000
K Søvold	Exec Director & CEO Non-Executive Director	PetroNor E&P AS Hemla E&P Congo SA	NOK 1,860,000 USD 60,000	240,790
G Ludvigsen	Business Development Manager Non-Executive Director	PetroNor E&P AS Hemla E&P Congo SA	NOK 1,860,000 USD 60,000	240,790
E Sultan	Strategy & Contracts Manager[1]	PetroNor E&P AS	USD 120,000	120,000
C Frimann-Dahl	Chief Technical Officer	PetroNor E&P AS	NOK 1,500,000	145,800
M Barrett	Exploration Manager	PetroNor E&P Services Ltd	GBP 150,000	186,000
C Butler	Group Financial Controller	PetroNor E&P Services Ltd	GBP 115,000	142,600

1. Fees are charged by related party Petromal LLC and are not paid to the individual; above figures represent the company's fair value estimate of associated costs for the individual's services

FX rates used as at 9th April NOK 1.00 : USD 0.0972 GBP 1.00 : USD 1.24

The rates of other cash benefits and post-employment benefits were unchanged.

When former Executive Officers, Jens Pace and Stephen West resigned these roles on 29 February 2020, the termination benefit equivalent to one year's salary was agreed to be paid out in equal monthly instalments over an 18- and 12-month period respectively.

Remuneration of key management personnel

2019	Designation	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Total USD
Management					
K Søvold	Exec Director & COO	**358,551**	**1,989**	**24,350**	**384,891**
J Pace[1]	Exec Director & CEO	**159,716**	**2,076**	**–**	**161,792**
S West[1]	Exec Director & CFO	**113,257**	**1,034**	**11,326**	**125,617**
G Ludvigsen	Business Development Manager	**360,119**	**466**	**25,829**	**386,414**
C Frimann-Dahl	Chief Technical Officer	**226,678**	**–**	**–**	**226,678**
M Barrett[1]	Exploration Manager	**125,491**	**506**	**–**	**125,617**
C Butler[1]	Group Financial Controller	**48,239**	**2,209**	**4,824**	**55,272**
E Alhomouz	Related party fees[2]	**361,488**	**–**	**–**	**361,488**
E Sultan	Related party fees[2]	**301,239**	**–**	**–**	**301,239**
A Hicks[1]	Company Secretary	**5,466**	**–**	**–**	**5,466**
		2,060,245	**8,280**	**66,329**	**2,134,854**
Directors' remuneration for PetroNor E&P Ltd Australia					
J Iskander[3]	Non-Exec Director	**–**	**–**	**–**	**–**
D King[1]	Non-Exec Director	**12,000**	**–**	**–**	**12,000**
B Moe[1]	Non-Exec Director	**11,000**	**–**	**–**	**11,000**
T Turner[1]	Non-Exec Director	**5,456**	**–**	**–**	**5,456**
		28,456			**28,456**
Directors' remuneration for subsidiaries					
E Alhomouz	Non-Exec for HEPCO	**120,000**	**120,000**		**120,000**
K Søvold	Non-Exec for HEPCO	**66,000**	**66,000**		**66,000**
G Ludvigsen	Non-Exec for HEPCO	**66,000**	**66,000**		**66,000**
A Georghiou[4,5]	Non-Exec for PetroNor E&P Ltd	**6,143**	**–**	**–**	**6,143**
H Marshad[5]	Non-Exec for PetroNor E&P Ltd	**5,500**	**–**	**–**	**5,500**
N Kouyialis[4,5]	Non-Exec for PetroNor E&P Ltd	**6,250**	**–**	**–**	**6,250**
		269,893	**–**	**–**	**269,893**

1. Table only includes post-completion remuneration to former Australian company PetroNor E&P Limited key management personnel, i.e. from 30 August 2019
2. Remuneration is not paid to the individual, as fees are included in a monthly lump sum charged by related party Petromal LLC, above figures represent the company's fair value estimate of associated costs for the individual's services.
3. Mr Iskander was appointed on 30 August 2019, and agreed to waive his remuneration
4. Appointed 17 April 2019
5. Individual ceased to be part of key management, upon completion of reverse acquisition of Australian company PetroNor E&P Limited on 30 August 2019

2018[1]	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Total USD
Management				
K Søvold	98,479	–	–	98,479
G Ludvigsen	100,270	–	–	100,270
E Alhomouz[2]	100,000	–	–	100,000
	299,018	–	–	299,018
Directors' remuneration for subsidiaries				
K Søvold	66,000	–	–	66,000
G Ludvigsen	60,500	–	–	60,500
E Alhomouz	106,500	–	–	106,500
	233,000	–	–	233,000

1. Comparative table represents remuneration of key management of consolidated group of PetroNor E&P Ltd, registered in Cyprus.
2. Remuneration is not paid to the individual, as fees charged by related party Petromal LLC; above figures represent the company's fair value estimate of associated costs for the individual's services.

During 2019, Employer's social taxes of USD 169,118 (2018: USD 28,062) were payable for the key management remuneration.

24. Related party transactions continued

Pro-forma remuneration for members of key management personnel from Australian company PetroNor E&P Limited, assuming the reverse acquisition had taken place on 1 January 2019:

2019	Salary and fees USD	Other cash benefits USD	Post-employment benefits USD	Share-based payments – options USD	Total USD
J Pace	485,444	7,585	–	–	493,209
S West	344,236	5,407	34,424	–	384,067
M Barrett	381,420	2,066	–	–	383,487
C Butler	146,619	5,115	14,662	–	166,396
D King	20,000	–	–	–	20,000
B Moe	19,000	–	–	–	19,000
T Turner	11,056	–	–	–	11,056
A Hicks	16,674	–	–	–	16,674
Total	**1,424,540**	**20,174**	**49,086**	**–**	**1,493,889**

Share holdings by Directors and other Key Management Personnel

	Balance 1 January 2019	Reverse acquisition net change	Shares purchased	Granted as remuneration	Net change other	Balance 31 December 2019
J Pace	–	1,498,938	–	–	–	1,498,938
S West	–	1,377,554	–	–	–	1,377,554
M Barrett	–	1,151,667	–	–	–	1,151,667
C Butler	–	234,296	–	–	–	234,296
C Frimann-Dahl	–	–	50,000	–	–	50,000
D King	–	30,000	–	–	–	30,000
B Moe	–	10,000	–	–	(10,000)	–
T Turner	–	4,167	–	–	–	4,167
	–	4,356,622	–	–	(10,000)	4,346,622

As at 31 December 2019, Eyas Alhomouz held no shares personally, but holds influence over 371,961,246 shares (2018: 50,000 shares) as the CEO of significant shareholder Petromal LLC.

As at 31 December 2019, 444,237,596 shares (2018: 50,000 shares) are held by NOR Energy AS, a company controlled jointly by Knut Søvold and Gerhard Ludvigsen through an indirect beneficial interest.

Other members of key management not included in the above table held no shares during the current year.

Warrant and option holdings by Directors and other Key Management Personnel

	Balance 1 January 2019	Reverse acquisition net change	Awarded as remuneration	Options exercised	Net change other	Balance 31 December 2019	Exercisable	Not Exercisable
J Pace	–	3,919,710	–	–	(3,919,710)	–	–	–
S West	–	3,761,902	–	–	(3,761,902)	–	–	–
M Barrett	–	2,712,424	–	–	(2,712,424)	–	–	–
C Butler	–	709,686	–	–	(709,686)	–	–	–
D King	–	615,536	–	–	(615,536)	–	–	–
B Moe	–	346,809	–	–	(346,809)	–	–	–
T Turner	–	238,382	–	–	(238,382)	–	–	–
A Hicks	–	62,753	–	–	(62,753)	–	–	–
	–	12,367,202	–	–	12,367,202	–	–	–

Members of key management not included in the above table held no warrants or options during the current year

24c. Significant Shareholders

Shareholder	Place of incorporation	31 December 2019 Ownership	31 December 2018 Ownership
Nor Energy AS	Norway	**46%**	50%
Petromal LLC – Sole Proprietorship LLC	UAE	**38%**	50%

24d. Transactions and period-end balances with related parties

Transactions with related parties included in the consolidated statement of comprehensive income:

	2019 USD'000	2018 USD'000
Nor Energy AS	**–**	753
Petromal – Sole Proprietorship LLC	**–**	1,582
Cost of sales	**–**	2,335
Nor Energy AS subsidiary company – loan write-off[1]	**5,305**	–
Nor Energy AS – charge back of expenses	**103**	1,000
Petromal – Sole Proprietorship LLC	**1,088**	–
Administrative expenses	**6,496**	1,000

Balances due from and due to related parties disclosed in the consolidated statement of financial position:

	2019 USD'000	2018 USD'000
Loan receivable from MGI International S.A.[2]	**5,639**	7,000
Loan receivable from Nor Energy AS subsidiary company[1]	**–**	5,700
Other receivable from Nor Energy AS	**–**	229
Total receivables from related parties (Note 13)	**5,639**	12,929
Other payable to Nor Energy AS	**5,783**	975
Other payable to Petromal – Sole Proprietorship LLC	**4,534**	1,163
Other payable to MGI International S.A.	**3,467**	–
Total payables to related parties (Note 18)	**13,784**	2,138

1 During 2017, Hemla Africa Holding AS provided a loan facility of USD 6 million to a Nor Energy AS subsidiary company, for which the borrower had an option to drawdown in one or more instalments. The loan did not carry any interest and was repayable on demand. However, prior to the merger on 30 August 2019, the outstanding balance of USD 5.3 million was written off to administrative expenses.

2 During the prior year, Hemla Africa Holding AS (HAH AS) provided a loan of USD 7 million to MGI International SA, (minority shareholder in Hemla E&P Congo SA (HEPCO). The loan will be repaid directly by HEPCO to HAH AS from its yearly dividends being 25% of MGI's share of dividend in the first year and 40% thereafter. The loan does not carry any interest unless there is a breach of any clause of the loan agreement in which case 4% p.a. will be accrued on the outstanding amount of loan.

Amounts due from/to related parties included in the consolidated statement of financial position (other than the loans to related parties) are interest-free and have no fixed repayment terms.

25. Risk Management

The Group's principal financial liabilities comprise accounts payable and amounts due to related parties. The main purpose of these financial instruments is to manage short-term cash flow and raise finance for the Group's capital expenditure programme. The Group has various financial assets such as accounts receivable and cash.

It is, and has been throughout the year ending 31 December 2019, the Group's policy that no speculative trading in derivatives shall be undertaken.

The main risks that could adversely affect the Group's financial assets, liabilities or future cash flows are credit risk, liquidity risk, interest rate risk and foreign currency risk. The management reviews and agrees policies for managing each of these risks which are summarized below.

The following discussion also includes a sensitivity analysis that is intended to illustrate the sensitivity to changes in the market variables on the Group's financial instruments and shows the impact on profit or loss and shareholders' equity, where applicable. Financial instruments affected by market risk include, accounts receivable, accounts payable and accrued liabilities.

25. Risk Management continued

The sensitivity has been prepared for periods ending 31 December 2019 using the amounts of debt and other financial assets and liabilities held as at those reporting dates.

Credit risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss.

The Group seeks to limit its credit risk with respect to banks by only dealing with reputable banks and with respect to customers by setting credit limits for individual customers and monitoring outstanding receivables. However, management is confident that this concentration of credit risk will not result in any loss to the Group due to the strong business relationship with and good reputation of the customers.

With respect to credit risk arising from the other financial assets of the Group, including cash and cash equivalents, the Group's exposure to credit risk arises from default of the counterparty, with a maximum exposure equal to the carrying amount of these instruments.

Liquidity risk

The Group seeks to limit its liquidity risk by ensuring financial support is available from the shareholders. The Group's terms of sales requires amounts to be paid within 45 to 60 days of the date of approval of progress billings. Trade payables are normally settled within 90 to 120 days of the date of receipt of invoice.

The table below summarises the maturity profile of the Group's financial liabilities at 31 December 2019 based on contractual undiscounted payments.

USD'000	Note	On demand	Less than 1 month	Between 1 and 3 months	Between 3 months and 1 year	More than 1 year	Total
31 December 2019							
Trade accounts payable	**18**	**616**	**1,580**	**2,483**	**10,130**	**–**	**14,809**
Amounts due to related parties	**24d**	**13,784**	**–**	**–**	**–**	**–**	**13,784**
Loan payable[1]	**19**	**–**	**588**	**1,176**	**11,176**	**–**	**12,941**
		14,400	**2,168**	**3,659**	**21,306**	**–**	**41,535**

USD'000	Note	On demand	Less than 1 month	Between 1 and 3 months	Between 3 months and 1 year	More than 1 year	Total
31 December 2018							
Trade accounts payable	18	–	3,787	–	–	–	3,787
Amounts due to related parties	24d	–	–	2,138	–	–	2,138
Loan payable	19	–	696	2,036	5,177	3,028	10,937
		–	4,483	4,174	5,177	3,028	16,862

1. Post year-end in April 2020, the loan was replaced with a USD 15 million facility with 12 months' grace period and final maturity date in October 2022.

The Company had USD 27.0 million (2018: 7.9 million) in unrestricted cash as of 31 December 2019. Should additional funding be required in the future for additional capital expenditure for new development phases or working capital requirements, the Company has various alternatives available which it can explore to fulfil such additional requirements. The options include, amongst others, debt financing, offtake prepayment structures. As a result, the financial statements have been prepared under the assumption of going concern and realisation of assets and settlement of debt in normal operations.

Interest rate risk

The Group is exposed to interest rate risk on its interest-bearing assets and liabilities and seeks to limit this risk by obtaining favourable interest rates.

	31 December 2019		31 December 2018	
	+150bp USD'000	**–150bp USD'000**	+150bp USD'000	–150bp USD'000
Loans payable	**(194)**	**194**	(106)	106

Currency risk

The Group operates internationally and is exposed to risk arising from various currency exposures, primarily with respect to the Norwegian Kroner (NOK) and the Great British Pound (GBP). The Group has transactional currency exposures. Such exposure arises from sales or purchases in currencies other than the respective functional currency.

The Group reports its consolidated results in USD; any change in exchange rates between its operating subsidiaries' functional currencies and the USD affects its consolidated statement of comprehensive income and statement of financial position when the results of those operating subsidiaries are translated into USD for reporting purposes.

Group companies are required to manage their foreign exchange risk against their functional currency.

A 20% strengthening or weakening of the USD against the following currencies at 31 December 2019 would have increased/(decreased) equity and profit or loss by the amounts shown below.

The Group's assessment of what a reasonable potential change in foreign currencies that it is currently exposed to have been changed as a result of the changes observed in the world financial markets. This hypothetical analysis assumes that all other variables, including interest rates and commodity prices, remain constant.

	31 December 2019		31 December 2018	
	+20% USD'000	**–20% USD'000**	+20% USD'000	–20% USD'000
USD vs NOK				
Cash	**45**	**(45)**	81	(81)
Receivables	**99**	**(99)**	678	(678)
Payables	**(246)**	**246**	(17)	17
	(102)	**102**	742	(742)
USD vs GBP				
Cash	**3**	**(3)**	–	–
Receivables	**11**	**(11)**	–	–
Payables	**(119)**	**119**	–	–
	(105)	**105**	–	–

Capital risk

The primary objective of the Group's capital management is to continuously evaluate measures to strengthen its financial basis and to ensure that the Group is fully funded for its committed 2020 activities. The Group manages its capital structure and makes adjustments to it in light of changes in economic conditions. In order to maintain or change the capital structure, the Group may adjust the amount of dividend payments to shareholders, return capital to shareholders or issue new shares. The Group has no significant debt arrangements in place and has the flexibility to source conventional debt capital from the markets.

The Group is continuously evaluating the capital structure, with the aim of having an optimal mix of equity and debt capital to reduce the Group's cost of capital, and looking at avenues to procure capital in the forthcoming year.

26. Financial instruments – Fair values

Financial instruments comprise financial assets and financial liabilities.

Financial assets consist of bank balances and cash, amounts due from related parties and trade and some other receivables. Financial liabilities consist of amounts due to related parties, loan payables, trade account payables and some other liabilities.

The fair values of the Group's financial instruments are not materially different from their carrying amounts at the reporting date largely due to the short-term maturities of these instruments.

27. Commitments and contingencies

Commitments

Exploration commitments

The Company has entered into obligations in respect of its exploration projects. Outlined below are the minimum expenditures required as at 31 December:

	2019 USD'000	2018 USD'000
Within one year[1]	**40,000**	–

1 The commitment in Senegal includes USD 40m for an exploration well in each licence, however this assumes that the Company is successful in retaining the legal title for these licences and that the Company then drills these wells with 90% equity.

Office rental commitments

The Company has entered into obligations in respect of office premises. Commitments for the payment of office rental in existence at the reporting date but not recognised as liabilities are as follows:

	2019 USD'000	2018 USD'000
Within one year	**188**	–
More than 1 year, less than 3 years	**201**	–
Total	**389**	–

28. Parent entity financial information

i. Summary financial information

The individual financial statements of the parent entity show the following aggregate amounts:

	2019 USD'000	2018 USD'000
Statement of financial position		
Current assets	**16,403**	42
Non-current assets	**104,027**	14,622
Total assets	**120,430**	14,664
Current liabilities	**(15,559)**	(246)
Total liabilities	**(15,559)**	(246)
Net Assets	**104,871**	14,418
Shareholders' equity		
Issued capital	**1,130,901**	1,039,121
Reserves	**29,391**	(6,192)
Accumulated losses	**(1,055,421)**	(1,018,511)
	104,871	14,418
Net loss for the year	**(1,357)**	(1,567)
Total comprehensive loss	**(1,357)**	(1,567)

ii. Guarantees entered into by the parent entity

As at 31 December 2019, the parent entity has not provided any financial guarantees in respect of bank overdrafts, decommissioning liabilities and loans of subsidiaries (31 December 2018: nil).

29. Events subsequent to reporting date

Board restructure

On 29 February 2020, Jens Pace stepped down as Chief Executive Officer, but remained on the Board as a Non-Executive Director. COO, Knut Søvold was immediately appointed the Chief Executive Officer. Also, on 29 February 2020, Stephen West resigned as the Chief Financial Officer and Executive Director.

Non-Executive Directors David King and Tim Turner resigned during February 2020; and were replaced by Alexander Neuling and Roger Steinepreis in April 2020.

COVID-19

Since the end of the financial year, the COVID-19 outbreak is a globally significant event impacting the health of individuals, international trade and commerce and, as a result, had a severely negative impact on global financial markets. The COVID-19 outbreak combined with the dramatic oil price decline has had a significant impact on the short-term oil prices. Consequently, this has adversely affected the Group's business.

The Company has initiated an immediate cost reduction in the Company overhead and general administration cost. The key management salaries have been reduced with immediate effect from mid-March 2019. A full review of the Company expenditures has been completed and cost reduction actions are being implemented on a continuous basis. It has been important for management to ensure that the cost savings initiatives have limited impact on the capabilities of the company to continue its growth strategy even under these difficult circumstances and the new venture strategy of the company. The implemented initiatives will reduce the "normal budget" for 12 months forward from USD 14.1 million to USD 10.5 million. This number excludes any ongoing commitments such as redundancy packages and other costs which will be tapered down going forward.

Arbitration

On 4 May 2020, the arbitration proceedings for the Group's interests in Senegal were suspended until 2 November 2020, following a mutual agreement between the parties.

Directors' declaration and statement of responsibility

We confirm that in the opinion of the Directors:

a) the financial statements and notes of PetroNor E&P Limited for the year ended 31 December 2019 are in accordance with the Corporations Act 2001, including:
   i. giving a true and fair view of its financial position as at 31 December 2019 and of its performance for the year ended on that date; and
   ii. complying with Australian Accounting Standards (including the Australian Accounting Interpretations) and the Corporations Regulations 2001; and
   iii. complying with International Financial Reporting Standards as disclosed in Note 2.

b) subject to the achievement of matters disclosed in Note 2 (Going Concern), there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

c) that the Directors' Report together with the Unaudited Additional Information includes a fair review of the development and performance of the business and the position of PetroNor E&P Limited and the Group taken as a whole, together with a description of the principal risks and uncertainties that they face; and

d) to the best of our knowledge, the country-by-country report for 2019 has been prepared in accordance with the Norwegian Security Trading Act Section 5-5a.

The Directors have been given the declarations required by Section 295A of the Corporations Act 2001 from the Chief Executive Officer, Knut Søvold, and the Group Financial Controller, Chris Butler, for the year ended 31 December 2019.

6 May 2020

The Board of Directors
PetroNor E&P Ltd

Eyas Alhomouz,
Chairman of the Board

Knut Søvold,
CEO and Executive Director of the Board

Jens Pace,
Director of the Board

Alexander Neuling,
Director of the Board

Joseph Iskander,
Director of the Board

Roger Steinepreis,
Director of the Board

Independent Auditor's Report
to the members of PetroNor E&P Limited

Report on the Audit of the Financial Report

Opinion

We have audited the financial report of PetroNor E&P Limited (the Company) and its subsidiaries (the Group), which comprises the consolidated statement of financial position as at 31 December 2019, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, and notes to the financial report, including a summary of significant accounting policies and the directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the *Corporations Act 2001*, including:

i. Giving a true and fair view of the Group's financial position as at 31 December 2019 and of its financial performance for the year ended on that date; and
ii. Complying with Australian Accounting Standards and the *Corporations Regulations 2001*.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the Financial Report* section of our report. We are independent of the Group in accordance with the *Corporations Act 2001* and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 *Code of Ethics for Professional Accountants (including Independence Standards)* (the Code) that are relevant to our audit of the Financial Report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the *Corporations Act 2001*, which has been given to the Directors of the Company, would be in the same terms if given to the Directors as at the time of this auditor's report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material uncertainty related to going concern

We draw attention to Note 2 in the financial report which describes the events and/or conditions which give rise to the existence of a material uncertainty that may cast significant doubt about the Group's ability to continue as a going concern and therefore the Group may be unable to realise its assets and discharge its liabilities in the normal course of business. Our opinion is not modified in respect of this matter.

Other matter

The financial report of PetroNor E&P Ltd, for the year ended 31 December 2018 was audited by another auditor who expressed an unmodified opinion on that report on 29 July 2019.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the Financial Report of the current period. These matters were addressed in the context of our audit of the Financial Report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. In addition to the matter described in the *Material uncertainty related to going concern* section, we have determined the matters described below to be the key audit matters to be communicated in our report.

Accounting for the reverse acquisition accounting transaction

Key audit matter	How the matter was addressed in our audit
During the year ended 31 December 2019, African Petroleum Corporation Limited acquired 100% interest in the shares of PetroNor E&P Ltd on 30 August 2019, as disclosed in Note 23a to the financial report. The Group treated the transaction as a reverse asset acquisition, rather than a business combination, as disclosed in Note 4 and Note 23a of the financial report. Accounting for these transactions is complex and requires management to exercise judgement to determine the appropriate accounting treatment, including whether the acquisitions should be accounted for as asset acquisitions or business combinations, estimating the fair value of net assets acquired and the determination of the non-controlling interest. As a result, this is considered a key audit matter.	Our procedures included, but were not limited to: • Obtaining an understanding of the transaction, including an assessment of whether the transaction constituted an asset acquisition or business combination; • Reading the sale and purchase agreement to understand key terms and conditions including identifying of the acquirer; • Agreeing the consideration to supporting documentation; • Evaluating management's assessment of the fair value of the net assets acquired; • Reviewing the warrant documentation to ensure they had been appropriately accounted for; • Assessing the accuracy of the comparative information in the Financial Statement; and • Assessing the adequacy of the related disclosures in Note 4 and Note 23a to the Financial Report.

Other information

The Directors are responsible for the other information. The other information comprises the information in the Group’s Annual Report for the year ended 31 December 2019, but does not include the Financial Report and the Auditor’s Report thereon.

Our opinion on the Financial Report does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information and, in doing so, consider whether the other information is materially inconsistent with the Financial Report or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Directors for the Financial Report

The Directors of the Company are responsible for the preparation of the Financial Report that gives a true and fair view in accordance with Australian Accounting Standards and the *Corporations Act 2001* and for such internal control as the Directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the Directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor’s responsibilities for the audit of the Financial Report

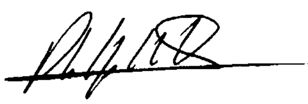
Our objectives are to obtain reasonable assurance about whether the Financial Report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

A further description of our responsibilities for the audit of the Financial Report is located at the Auditing and Assurance Standards Board website at: http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf

This description forms part of our auditor’s report.

Responsibilities

The Directors of the Company are responsible for the preparation and presentation of the Remuneration Report in accordance with section 300A of the *Corporations Act 2001*. Our responsibility is to express an opinion on the Remuneration Report, based on our audit conducted in accordance with Australian Auditing Standards.



Phillip Murdoch
Director

BDO Audit (WA) Pty Ltd
Perth, 6 May 2020

Unaudited additional shareholder information

In compliance with Oslo listing requirements and Section 3-3a of the Norwegian Accounting Act, the following information is provided in addition to the information set-out elsewhere in this Annual Report.

Reporting – payments to governments' statement

This country-by-country report has been developed to comply with the legal requirements in the Norwegian Security Trading Act ("Verdipapirhandelloven") § 5-5a, valid from 2014. The detailed regulation can be found in the regulation "Forskrift om land-for-land rapportering".

In 2019, the Company was engaged in extracting activities encompassed by the legislation above in the following countries: Republic of Congo, Nigeria, The Gambia, and Senegal. This report discloses relevant payments to governments for extractive activities in the countries above, in addition to some contextual information as required by the regulation in the "Forskrift om land-for-land rapportering".

Basis for preparation

The report includes direct payments to governments from subsidiaries, joint operations and joint ventures. In some cases, however, certain payments to governments may be made by an operator on behalf of a partnership. This is often the case for area fees. In such cases, the Company will report their paying interest share of the payment made by the operator.

Definitions

Government – In the context of this report, a government means any national, regional or local authority of a country. It includes a department, agency or undertaking controlled by that authority.

Project – For this reporting a project is defined as an investment in a concession agreement.

Licence fees – Typically levied on the right to use a geographical area for exploration, development and production and include rental fees, area fees, entry fees, severance tax and concession fees and other considerations for licences and/or concessions. Administrative government fees that are not specifically related to the extractive sector, or to access extractive resources, are excluded.

Materiality – As per the "Forskrift om land-for-land rapportering" payments made as a single payment, or as a series of connected payments that equal or exceed Norwegian Kroner (NOK) 800.000 during the year are disclosed.

Reporting currency – Payments to governments are converted from the functional currency of each legal entity into the presentation currency, United States Dollars (USD). The payments for entities whose functional currencies are other than USD are converted into USD at the foreign exchange rate at the average annual rate.

Payments to governments and contextual information

The consolidated overview below discloses the sum of the Company's payments to governments in each individual country where extractive activities are performed, per country/project.

Payments per project

Project	Royalties / USD' 000	Oil tax / USD' 000	Other amounts / USD'000	Total / USD'000
PNGF Sud	15,387	29,894	2,174	47,455
Total Republic of Congo	**15,387**	**29,894**	**2,174**	**47,455**
Aje	Nil	Nil	Nil	Nil
Total Nigeria	**Nil**	**Nil**	**Nil**	**Nil**
A1	Nil	Nil	Nil	Nil
A4	Nil	Nil	Nil	Nil
Total The Gambia	**Nil**	**Nil**	**Nil**	**Nil**
ROP	Nil	Nil	Nil	Nil
SOSP	Nil	Nil	Nil	Nil
Total Senegal	**Nil**	**Nil**	**Nil**	**Nil**

Other amounts includes payroll and other local taxes

Legal entities by country

as per the "Forskrift om land-for-land rapportering" it is required that the Company report on certain contextual information at corporate level. This includes information on localisation of subsidiary, employees per subsidiary and interests paid or payable to other legal entities within the Group.

Legal corporate structure of the Group during 2019 is set out below:

Name	Country of incorporation	Main country of operations	Employees[1]	Interest paid or payable to a group entity /USD
PetroNor E&P Ltd	Australia	United Kingdom	–	–
PetroNor E&P Ltd	Cyprus	Cyprus	1	387,025
PetroNor E&P AS	Norway	Norway	3	–
PetroNor E&P Services Ltd	United Kingdom	United Kingdom	2	–
PetroNor E&P Nigeria Ltd	Nigeria	Nigeria	2	–
Hemla African Holding AS	Norway	Norway	–	–
Hemla E&P Congo SA	Republic of Congo	Republic of Congo	5	–
African Petroleum Corporation Ltd	United Kingdom	United Kingdom	–	–
African Petroleum Corporation Ltd	Cayman Islands	United Kingdom	–	–
African Petroleum Gambia Ltd	Cayman Islands	The Gambia	1	–
African Petroleum Senegal Ltd	Cayman Islands	Senegal	–	–
African Petroleum Senegal SAU	Senegal	Senegal	1	–
African Petroleum Sierra Leone Ltd	Cayman Islands	Sierra Leone	–	–
African Petroleum (SL) Ltd	Sierra Leone	Sierra Leone	–	–
APCL Gambia B.V.	Netherlands	The Gambia	–	–
European Hydrocarbons Ltd	Cayman Islands	United Kingdom	–	–

1. Employees' number is the average during the year

Glossary and definitions

Bbl	One barrel of oil, equal to 42 US gallons or 159 liters
Bcf	Billion cubic feet
bbl/d	Barrels of oil per day
CPP	Production sharing contract, “Contrat de Partage de Production” in French
CPR	Competent Person’s Report
Group or PetroNor Group	PetroNor E&P Ltd and its subsidiaries
IOR	Improved oil recovery
MMbbl	Million barrels of oil
MMBOE	Million barrels of oil equivalent
Mmscfd	Million standard cubic feet per day
PDP	Proven Developed Producing (reserves)
PSC	Production sharing contract
SNPC	Société National des Pétroles du Congo

Corporate directory

Directors
Eyas Alhomouz, Chairman
Joseph Iskander
Alexander Neuling
Jens Pace
Knut Søvold, Chief Executive Officer
Roger Steinepreis

Company Secretary
Angeline Hicks

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Stock exchange listing
Oslo Axess
Code: PNOR

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APPENDIX E:

AUDITED CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEAR ENDED 31 DECEMBER 2018

African Petroleum CORP LTD

Annual report and accounts 2018

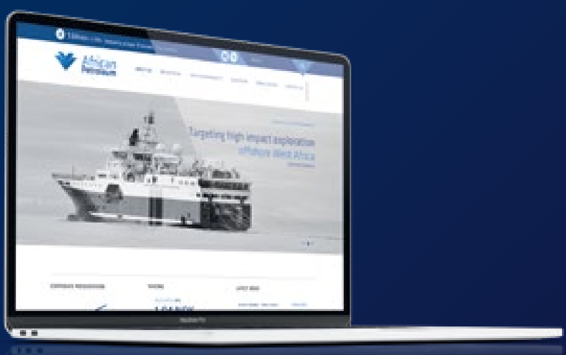
African Petroleum Corporation Ltd

African Petroleum is an independent oil and gas exploration company led by an accomplished Board and management team, with substantial experience in oil and gas exploration, appraisal, development and production

Strategic report

Governance

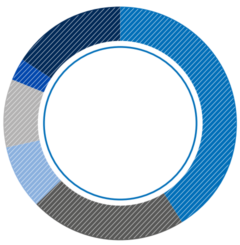
Financial statements



To find out more visit
www.africanpetroleum.com.au

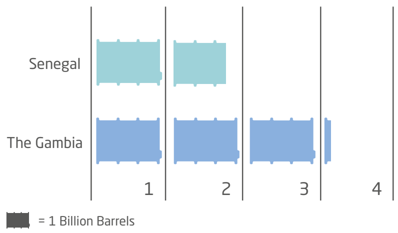
Geographical analysis of investors (%)

- Norway – 41.2
- Sweden – 21.7
- UK – 8.8
- Rest of Europe – 9.6
- North America – 2.9
- Rest of World – 15.8



Net unrisked mean prospective oil resources (bnbbls)

Oil distribution by country



Senegal

- Focus on protecting historical investments in Senegal
- Requests for arbitration in respect of licences ROP and SOSP in Senegal filed with ICSID in Q3 2018
- Request for provisional measures filed with ICSID in Q1 2019

Sierra Leone

- Unsuccessful efforts to find partners for blocks SL-03-17 and SL-04A-17
- Relinquished blocks in Q4 2018 to avoid commitment to ultra-deep-water drilling programme
- Relinquishment in line with strategy to prioritise assets with most upside potential

The Gambia

- Continued arbitration proceedings from Q4 2017
- Hearing on Government of the Gambia's preliminary objections in Q4 2018
- Filed memorial on admissibility, jurisdiction and the merits with ICSID in Q1 2019

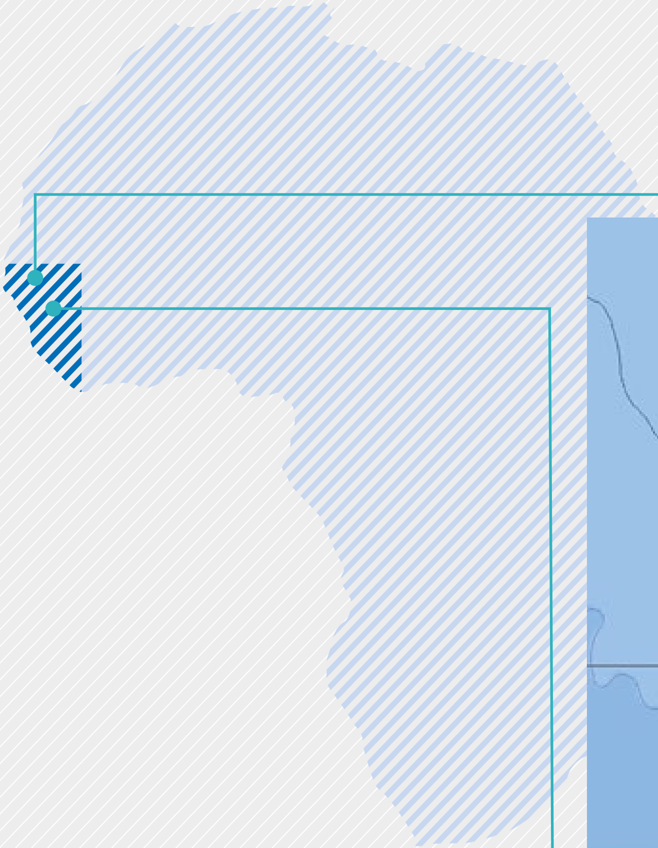
Developing our business

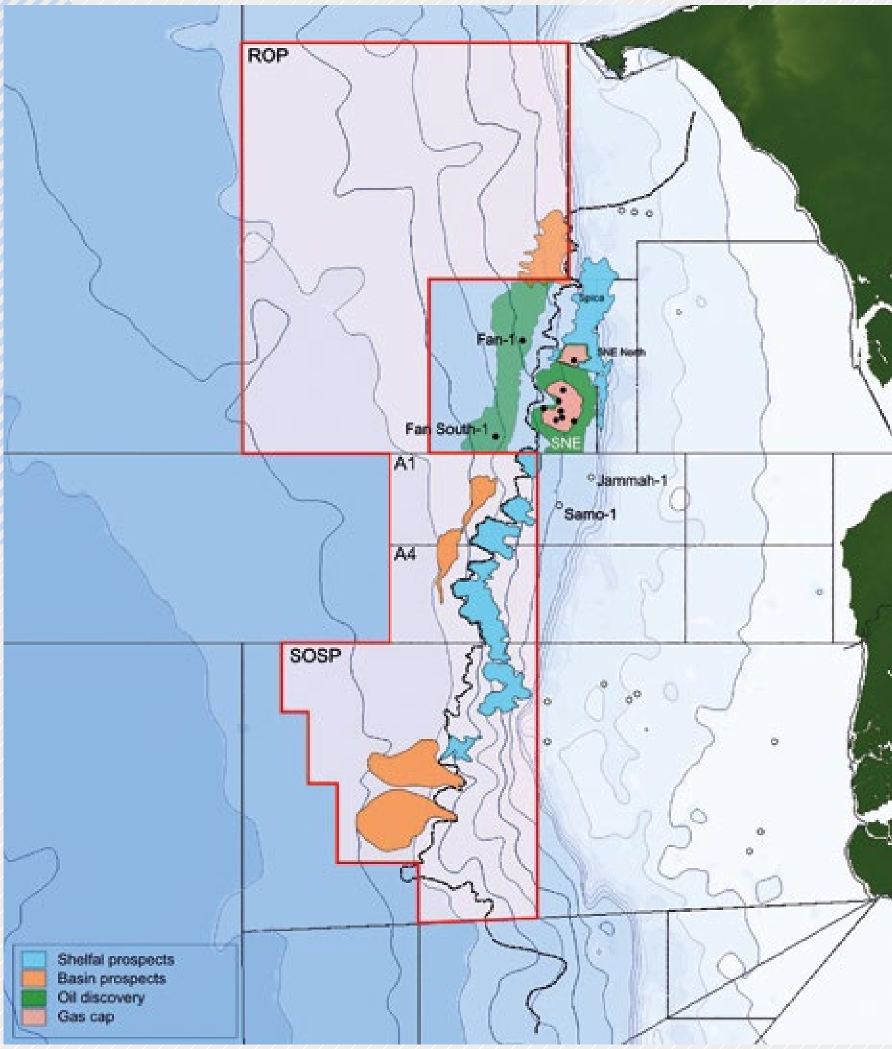
- Strategic review to ensure sustainability of the Company, independent of the outcome in Senegal and The Gambia
- Actively sought to merge with complementary company to achieve scale and diversify risk
- Proposed PetroNor E&P combination provides high-quality assets and associated strong cash flow profile

Find out more on PG06

At a glance

African Petroleum was founded in 2010 and has equity interests in four licences in West Africa: Senegal and The Gambia





16,888km²

Total net acreage held in four blocks in Senegal and The Gambia

4.9 billion barrels

Net unrisked mean prospective oil resources (independently assessed)

How we operate

To date the Company has acquired more than 13,400km^2 of 3D seismic data and participated in the drilling of four exploration wells in the region

Senegal

The Group holds a 90 per cent operating interest in licences Rufisque Offshore Profond ("ROP") and Senegal Offshore Sud Profond ("SOSP"). African Petroleum has licensed over 10,000km^2 of 2D seismic data and 5,100km^2 3D seismic data over both licences. Both licences are positioned in a high potential exploration area, as demonstrated by third party oil discoveries and successful appraisal wells drilled in the adjacent acreage by Cairn Energy.

The Group is currently in dispute with the Senegalese government regarding the status of the ROP and SOSP licences and ICSID arbitration proceedings have been initiated.

Net Offshore Acreage Position km^2

Block SOSP	4,895
Block ROP	9,321

90% operating interest

The Gambia

The Group holds a 100 per cent operating interest in licences A1 and A4. The Group has acquired 3D seismic data across both blocks and has found a number of analogue leads and prospects in its acreage similar to that of the recent discoveries and appraisal wells drilled by Cairn Energy in Senegal.

The Group is currently in dispute with the Gambian government regarding the status of the A1 and A4 licences and ICSID arbitration proceedings have been initiated.

Net Offshore Acreage Position km^2

Block A1	1,296
Block A4	1,376

100% operating interest

Our technology

African Petroleum utilises the latest technology to identify and de-risk prospects ahead of the drill bit, and employs the latest equipment for its offshore drilling operations.

Seismic acquisition and processing

- High-quality 3D seismic data acquisition from leading contractors
- PSDM volumes and reprocessing executed for several countries

Geological and geophysical interpretation

- State-of-the-art stratigraphic analyses and workflows
- Rock physics, forward modelling and attributes integrating latest well results
- Regional studies for reservoir distribution and quality
- 3D Basin modelling

Technologies utilised during drilling operations

- In deep water and remote locations, data is reliably obtained and transmitted to the drilling and G&G teams to facilitate rapid decision-making
- 6th and 7th generation semi-submersible rigs and drill ships
- Precise well design and rigorous execution
- Efficient high-quality data gathering and evaluation

Partnerships

African Petroleum is a significant acreage holder in West Africa, with high equity positions in all of its licences, offering a unique opportunity to strategic partners to share risk and rewards.

A catalyst for change

I am pleased to provide the following statement, which will be both my last as Chairman of the Company and the last for African Petroleum in its current form following the recently announced proposed merger with PetroNor E&P Ltd ("PetroNor E&P") to transform the Company into a full-cycle E&P company.

Our corporate agenda through the year was dominated by our efforts to protect the value of our historic investments in our assets in The Gambia and Senegal. The decision to commence arbitration proceedings against both countries was not taken lightly; however, the Board determined it to be the most appropriate way to achieve our primary objective of protecting value for our shareholders.

We embarked on the arbitration process with a pragmatic view about the potential length, costs and uncertainty associated with it. Moreover, we did so in the steadfast belief that our legal position is robust and that the Company is the rightful owner of the A1 and A4 blocks in The Gambia, and the SOSP and ROP blocks in Senegal. We remain confident in our stance and hopeful that the independent channels of arbitration will find in our favour. We also continue to state publicly that we remain open to engagement with the relevant authorities with a view to establishing a mutually beneficial agreement that avoids costly and prolonged legal disputes for all parties.

During the year, the Board also made the decision to rationalise the Company's portfolio and focus our sole attention on the assets which possess the most long-term potential. Following the unsuccessful drilling campaign with our partner Ophir Energy on block CI-513 during 2017, the Company exited its licences in Côte d'Ivoire. Further, after the Company's decision to not commit to an ultra-deep-water drilling programme, the Company also relinquished its interests in licences SL-03-17 and SL-4A-17 in Sierra Leone.

The decision to relinquish assets and narrow the focus of the portfolio was a necessary move to reduce our costs and future capital commitments, however it also highlighted the importance of binary outcomes in Senegal and The Gambia, being our last remaining assets. Against this backdrop, the focus of the Board through the second half of the year was to consider strategic initiatives to strengthen the Company's position with regards to the ongoing arbitration and create a more balanced and stable business that could generate sustainable value for our shareholders. A number of corporate and asset opportunities were considered before we engaged with PetroNor E&P, the Company with which we expect to merge with following the vote in favour of the combination by shareholders.

The Board believes that the proposed merger with PetroNor E&P represents an exciting opportunity to achieve scale and create value, by leveraging a diverse, pan-African portfolio underpinned by stable cash flow and proven reserves, as well as assets in one of the most exciting exploration postcodes in the world. The enlarged Company will also benefit from a significantly stronger balance sheet and an enhanced network throughout the continent, both of which we believe will strengthen our ability to achieve positive outcomes with regards to the arbitrations and to pursue various opportunities within our geographical area of focus.

The new Company, to be named PetroNor E&P, will be positioned for long-term growth, and will have a profile far more suited to the current sentiment of investors and industry. In this regard, we look forward to completing the final chapter of African Petroleum's story and commencing the story of PetroNor E&P with a clear strategic vision and confidence in our ability to create long-term value for all shareholders.

David King
Chairman

Chief Executive's statement

Ensuring sustainability

Last year was an eventful year in which the Company reshaped the portfolio, sought to protect historic value in our most valuable assets, and importantly, considered strategic initiatives that would deliver sustainable value for our shareholders.

The lack of tangible progress during prolonged discussions with the relevant authorities of Senegal and The Gambia left the Company with little choice other than to activate the dispute mechanisms associated with our licences. It was with regret that we were not able to reach an amicable and pragmatic agreement, but African Petroleum staunchly maintains that it is the rightful owner of these blocks by law, and as such we will continue to do everything in our power to retain them. We remain open to the concept of constructive dialogue with the relevant authorities and hope that sense will eventually prevail for the benefit of all parties.

With a substantial level of cost and uncertainty associated with the eventual outcome of the arbitration proceedings, and despite the surety of our own legal position, the Board's objective for the year was focused on streamlining the Company to ensure it could withstand a prolonged legal process. As part of this process, we relinquished the assets within the portfolio that provided the least amount of near-term potential.

The decision to withdraw from Côte d'Ivoire followed the extensive analysis of data obtained with the unsuccessful Ayamé-1X exploration well drilled in May 2017. The joint venture concluded that the remaining prospectivity of the CI-513 block did not represent an attractive investment opportunity that would justify entering the next phase of the production sharing agreement, and the work programme and financial commitment therein. Further, our efforts to find a suitable partner for the CI-509 block were unsuccessful and as such we also withdrew from the block.

Sierra Leone formed the only active segment of our portfolio and, having entered into the Second Extension Periods of SL-03-17 and SL-4A-17, we continued our efforts throughout the year to attract industry partners for these licences. Ultimately, the industry appetite for ultra-deep-water exploration of this kind did not exist against an industry backdrop of risk-averse, cost discipline. With the proposed terms of further extension being that the Company had to commit to drilling a well that would have been a world record water depth, it was a simple decision to relinquish these assets.

With our remaining assets tied up in arbitration and progress no longer in our control, the Board considered strategic initiatives that would ensure the sustainability of the Company, no matter the outcome of the Gambia and Senegal arbitration processes. The key criteria for any combination was to find a company with a portfolio that would complement our own, and a management team with a shared strategic vision of how to create long-term value. PetroNor E&P meets this criteria, and their high-quality assets and associated strong cash flow profile will upon completion ensure the sustainability of the Company and create a compelling, full-cycle, pan-African independent E&P Company. Furthermore, we firmly believe that the enlarged Company, with a stronger balance sheet and enhanced network across the continent, will ensure we can fund the arbitration through to its eventual conclusion, and may result in the commencement of constructive dialogue to bring the arbitration cases to an early conclusion.

The Board is wholly confident that the proposed merger with PetroNor E&P will benefit the shareholders of both companies and represents the creation of an exciting new player with a compelling pipeline of near-term opportunities to consider. We look forward to completing that transaction and delivering on the objectives that underpinned the rationale for the merger.

Jens Pace
Chief Executive Officer

Combining with PetroNor E&P

Transforming African Petroleum into a full-cycle exploration and production company

PetroNor E&P is a privately owned, Africa-focused E&P independent, that holds a 10.5% indirect interest in the PNGF Sud fields and the right to negotiate entry into a 14.7% indirect interest in an exploration license covering the PNGF Bis fields. Subject to certain customary conditions, African Petroleum will at completion of the transaction change its name to PetroNor E&P Limited.

c. 816m shares

The Company will (subject to completion) combine with PetroNor for an all-share consideration of c. 816 million shares in African Petroleum

c. 155m warrants

The existing African Petroleum shareholders will receive one for one (c. 155 million) warrants to preserve potential upside from the Company's existing exploration portfolio in The Gambia and Senegal

Transaction highlights

Changing our focus

The proposed transaction transforms the Company from an exploration-focused player into a cash flow-generating producer with a significant growth profile

Low risk – Long life

The proposed transaction provides the Company with diversified, low-risk, long-life and high-quality producing assets, with current net (working interest) production of c. 2,300 bbl/d and medium-term exploration upside in a well-established operating jurisdiction

- Africa-focused E&P company
- Strong operational experience and partnerships
- Extensive network in Africa ensuring strong deal pipeline
- Full-cycle platform with significant upside

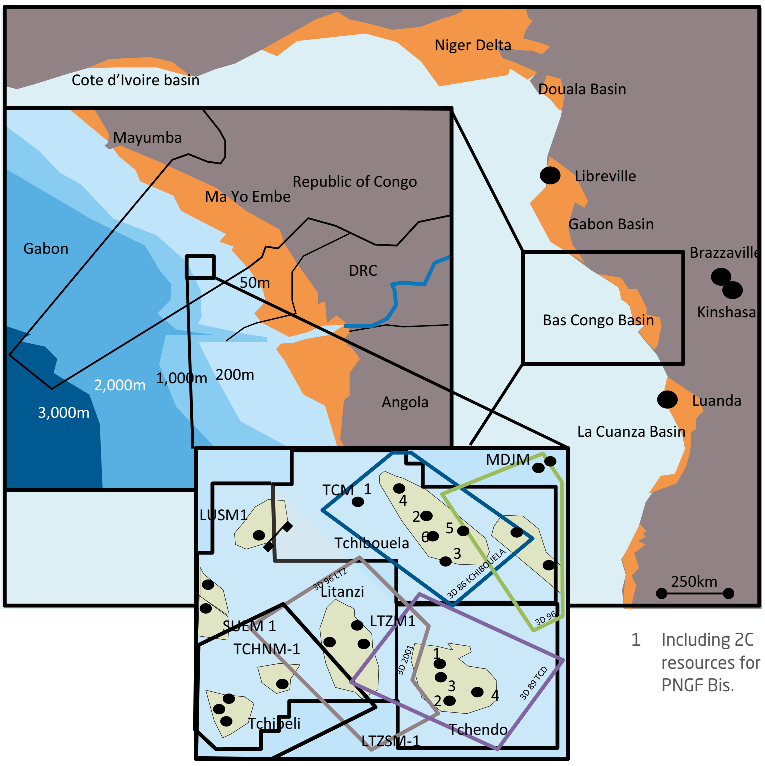
About PetroNor E&P

PetroNor E&P is a privately held, Africa-focused E&P independent, which is owned 50% by Petromal Sole Proprietorship LLC and 50% by NOR Energy

Petromal is the oil and gas arm of National Holding L.L.C., one of Abu Dhabi's leading investment groups with interests in industrial, investment, property, general trading and the oil & gas industry. NOR Energy is a privately owned oil company with its history from the North Sea and Africa.

PetroNor holds a 10.5% indirect interest in PNGF Sud and has a right under the umbrella agreement related to PNGF Sud, to in good faith negotiate with the Republic of Congo an entry into a 14.7% indirect interest in PNGF Bis. Following finalisation of license terms for PNGF Bis, the Combined Company intends to enter into a production sharing contract for this license, with Perenco as the operator.

Geographical location



1 Including 2C resources for PNGF Bis.

PNGF Sud

- PNGF Sud is located 25 km off the coast of Pointe Noire
  - Comprises four producing fields
  - Oil is exported via the Djeno terminal, and via the Nkossa FPSO
- PNGF Bis is located to the northwest of PNGF Sud, c. 11km from its producing fields
  - Three exploration wells to date
  - Two wells have flowed oil on test

Standalone key metrics


8.5 mmbbl of net 2P Reserves


7.6 mmbbl of net 2C Resources[1]


~2,300 bbl/d of net oil production

Directors' report

Your Directors present their report on African Petroleum Corporation Limited ("African Petroleum" or the "Company") for the year ended 31 December 2018.

Directors

The names of Directors in office during the financial year and until the date of this report are as follows. Directors were in office for this entire period unless otherwise stated.

Dr David King	Non-Executive Chairman
Mr Jens Pace	Executive Director and Chief Executive Officer
Mr Stephen West	Executive Director and Chief Financial Officer
Mr Bjarne Moe	Non-Executive Director
Mr Timothy Turner	Non-Executive Director
Mr Anthony Wilson	Non-Executive Director, resigned 12 April 2018

Company Secretary

Ms Angeline Hicks

Principal activity

The Company's principal activity during the year was oil and gas exploration.

Review of operations

Arbitration Proceedings – The Gambia

The Company's subsidiary African Petroleum Gambia Limited initiated arbitration proceedings at the International Centre for the Settlement of Investment Disputes ("ICSID") which were registered on 17 October 2017 to protect its interests in the A1 and A4 licences in The Gambia (ICSID case ARB/17/38). Following the constitution of the tribunal on 26 March 2018 and the filing of preliminary objections by the Republic of The Gambia on 25 April 2018, the first session of the tribunal was held on 27 June 2018 which was predominantly to agree procedural matters. On 30 November 2018, the tribunal held a hearing on preliminary objections under the ICSID Arbitration Rule 41(5), and subsequently issued a decision on 31 December 2018. On 28 February 2019, the Company filed with the tribunal a memorial on admissibility, jurisdiction and the merit, a response to the memorial is expected in due course.

The Company remains open to engaging in constructive dialogue with the Gambian authorities, with a view to establishing a satisfactory solution that is in the interests of all parties.

Arbitration Proceedings – Senegal

The Company's subsidiary African Petroleum Senegal Limited registered a request for arbitration proceedings with ICSID on 11 July 2018 (ICSID case ARB/18/24) to protect its interests in the Senegal Offshore Sud Profond ("SOSP") and Rufisque Offshore Profond ("ROP") blocks in Senegal. On 18 December 2018, the Company filed a request for provisional measures with ICSID. Following the constitution of the tribunal on 23 February 2019, the first session of the tribunal was held on 19 March 2019 which was to predominantly agree procedural matters. On 22 March 2019 the tribunal held a hearing on the provisional measures request lodged by the Company. A decision on the provisional measures request is expected in due course.

The Company remains open to engaging in constructive dialogue with the Senegalese authorities through appropriate and official channels, with a view to establishing a satisfactory solution that is in the interests of all parties.

Licence Relinquishment – Sierra Leone

On 22 November 2018, the Company announced the relinquishment of its interests in licenses SL-03-17 and SL-4A-17 with immediate effect. This followed a period of discussion with the Petroleum Directorate of Sierra Leone, during which the parties failed to agree an extension to the licences on suitable terms. The Company was not able to not commit to an ultra-deep-water drilling program and accordingly relinquished these licences. After relinquishment, previous exploration commitments required by the licences that had been capitalised, including surface rental, social and training obligations, as well as past signature bonuses have been written off as an impairment expense within the consolidated statement of comprehensive income.

Licence Relinquishment – Côte d'Ivoire

Following the post-well analysis work of the Ayamé-1X exploration well in May 2017, it was concluded that the remaining prospectivity of the CI-513 block did not represent an attractive investment opportunity that would justify entering the next phase of the PSC and associated work programme and financial commitment therein. Subsequently on 8 March 2018, the Company announced the intention to relinquish its interests in licenses CI-509 and CI-513. The previous year's impairment provision for exploration and evaluation assets has been crystallised.

Exploration activities

The Company is an oil and gas exploration group currently focused on exploration offshore West Africa. The Company's assets are located in fast-emerging hydrocarbon basins. The Company has acquired more than 13,400km^2 of 3D seismic data on its existing and former licences and participated in the drilling of four exploration wells in West Africa. African Petroleum is a significant net acreage holder in West Africa with estimated net unrisked mean prospective resources of approximately 4.9 billion barrels. Table 1 below shows a detailed overview of the Company's licence interests.

Table 1: Summary of licences

Country	Licence	Operator	Working Interest	Grant Date	End Current Phase	Area km^2	Outstanding Commitments in Current Phase
Senegal	Rufisque Offshore Profond	African Petroleum Senegal Limited	90%[1]	Oct 2011	Oct 2015[2]	10,357	One exploration well
Senegal	Senegal Offshore Sud Profond	African Petroleum Senegal Limited	90%[1]	Oct 2011	Dec 2017[2]	5,439	Further geoscience and one contingent exploration well
The Gambia	A1	African Petroleum Gambia Limited	100%[3]	Sep 2006	Sep 2016[4]	1,296	One exploration well to be drilled on either A1 or A4
The Gambia	A4	African Petroleum Gambia Limited	100%[3]	Sep 2006	Sep 2016[4]	1,376	See above

1 Société des Pétroles du Sénégal has an option to increase its 10% interest to 20% following exploitation authorisation.
2 These licences are currently in arbitration proceedings with ICSID.
3 The Gambia National Oil Company has an option to acquire a 10% participating interest in the Licence from the development stage.
4 These licences are currently in arbitration proceedings with ICSID.

As part of the Group's business strategy, it is actively seeking partners to farm-in to its licences in order to share the risk and potential reward of the Company's highly prospective assets whilst also renegotiating some terms of licences. The farm-outs will reduce the Company's working interest and is part of a process of maturing the Group's asset portfolio and is initiated to *inter alia* reduce the Group's capital commitments, generate cash sales proceeds for funding of future operations as well as the introduction of technically and operationally competent joint venture partners to the Group's licences.

Senegal
Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Senegal Licences and estimates the net unrisked mean prospective oil resources at 1,779MMStb.

The Gambia
Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Gambian Licences and estimates the net unrisked mean prospective oil resources at 3,079MMStb.

Result
African Petroleum reported a loss after income tax of US$8,412,162 for the year ended 31 December 2018 (2017: US$35,019,552).

Dividends paid or recommended
The Directors do not recommend the payment of a dividend and no amount has been paid or declared by way of a dividend to the date of this report.

Significant events after the balance date
On 19 March 2019, the Company announced the proposed combination with PetroNor E&P Ltd ("PetroNor") for an all-share consideration of approximately 816 million shares in African Petroleum (the "Transaction"). PetroNor is a privately owned, Africa-focused E&P independent, that holds a 10.5% indirect interest in the PNGF Sud fields and right to negotiate entry into a 14.7% indirect interest in an exploration license covering the PNGF Bis fields located in Congo Brazzaville. The Transaction is subject to shareholder approval, and certain other customary conditions. African Petroleum will at completion of the Transaction change its name to PetroNor E&P Limited.

On 29 March 2019, notice was given that the General Meeting of Shareholders to approve the Transaction will be held on 24 April 2019. On 24 April 2019, the Company announced that all resolutions put forward at the General Meeting of the Company were passed on a show of hands.

Likely developments and expected results
The expected results of the Company will vary significantly dependent on the completion of the Transaction with PetroNor. The Transaction is unanimously recommended by the Board of Directors of African Petroleum. However as at the date of this report, the Transaction has not completed.

Assuming that the Transaction is completed successfully, the Company will be transformed from an exploration-focused company into a cash flow-generating producer with a significant growth profile. The Transaction provides the Company with diversified, low-risk, long-life and high-quality producing assets, with current net (working interest) production of approximately 2,300 bbl/d and medium-term exploration upside in a well-established operating jurisdiction.

If the Transaction is not completed, the Company will endeavour to complete the arbitration processes and seek to retain its interests in its West African projects. The arbitration processes will take longer than the next 12 months to complete. In the meantime, the Company will continue to attempt to resolve the arbitration processes early via constructive dialogue with the respective Senegalese and Gambian authorities.

Environmental regulation and performance
The Company is aware of its environmental obligations with regards to its exploration activities and ensures that it complies with the relevant environmental regulations when carrying out any exploration work. There have been no significant known breaches of the Company's exploration license conditions or any environmental regulations to which it is subject.

Significant changes in the state of affairs
There have been no significant changes in the Company's state of affairs during the current year.

Directors' report continued

Information on Directors

Dr David King	Chairman
Qualifications	Dr King graduated from the University of East Anglia with a BSc (Hons) in Class 1 Physics/Mathematics, holds a MSc and D.I.C. in Geophysics from the Imperial College, University of London and a PhD in Seismology from the Australian National University.
Experience 	Dr King is a professional geoscientist and has over 30 years' experience in oil and gas and other natural resources industries. He has co-founded, as well as held executive and non-executive board positions with, a number of successful ASX listed oil and gas exploration companies, including Eastern Star Gas Limited, Gas2Grid Limited and Sapex Limited. Dr King is currently non-executive chairman of ASX-listed biotechnology research and development company Cellmid Ltd and non-executive director of oil and gas companies Galilee Energy Ltd and Tapoil Ltd. He is also a non-executive director (formerly chairman) of AIM-listed (formerly ASX-listed) Litigation Capital Management Ltd. In a long corporate career, he has also served as managing director of ASX listed gold producer North Flinders Mines, and chief executive officer of oil & gas producers Beach Petroleum and Claremont Petroleum. He was more recently chairman of ASX listed Robust Resources Limited, chairman of AIM listed Tengri Resources, and non-executive director of ASX listed Republic Gold Limited. From 1974-76, Dr King was a Research Fellow with the Royal Norwegian Council for Scientific and Industrial Research (NTNF), working on the NORSAR seismic array. Dr King is a Fellow of the Australian Institute of Company Directors, a Fellow of the Australasian Institute of Mining & Metallurgy, a Fellow of the Australian Institute of Geoscientists, a member (and past President) of the Australian Society of Exploration Geophysicists, an active member of the Society of Exploration Geophysicists and a member of the Petroleum Exploration Society of Australia.
Interest in Shares and Options	As at the date of this report, Dr King holds 30,000 shares, 500,000 options with an exercise price of NOK 7.75 and an expiry date of 31 May 2022, and 500,000 options with an exercise price of NOK 1.60 and an expiry date of 31 May 2023.
Jens Pace	**Executive Director and Chief Executive Officer**
Qualifications	Mr Pace holds a BSc in Geology and Oceanography from the University of Wales and an MSc in Geophysics from Imperial College, London.
Experience 	Mr. Pace has a background in geosciences, and has had a career spanning over 30 years at BP Exploration Operating Company Limited ("BP"), and its heritage company Amoco (UK) Exploration Company. Mr. Pace has held senior positions at BP for over 10 years, gaining exploration and production experience in Africa, namely: Algeria, Angola, Congo, Gabon and Libya. In addition, he has experience in Europe, Russia and Trinidad. He has contributed to a number of BP's exploration discoveries over his career. Most recently, Mr. Pace managed a large and active exploration portfolio for BP in North Africa. In addition to exploration activities, Mr. Pace has gained experience in the areas of field development and as a commercial manager. Mr. Pace joined African Petroleum as Chief Operating Officer in October 2012, and was appointed Chief Executive Officer by the Board in November 2015.
Interest in Shares and Options	As at the date of this report, Mr Pace holds 1,498,938 shares, 200,000 options with an exercise price of NOK 4.00 and an expiry date of 28 April 2020, 350,000 options with an exercise price of NOK 1.70 and an expiry date of 15 November 2020, 1,000,000 options with an exercise price of NOK 1.70 and an expiry date of 22 December 2020, 1,500,000 options with an exercise price of NOK 7.75 and an expiry date of 31 May 2022, 1,500,000 options with an exercise price of NOK 1.60 and an expiry date of 31 May 2023 and 50,000 performance rights subject to the Company securing a commercial discovery.
Stephen West	**Executive Director and Chief Financial Officer**
Qualifications	Mr West is a qualified Fellow Chartered Accountant (Australia & New Zealand) and a Chartered Accountant (England & Wales) who holds a Bachelor of Commerce (Accounting and Business Law) from Curtin University of Technology in Australia.
Experience 	Mr West has over 23 years of financial and corporate experience gained in public practice, oil and gas, mining and investment banking spanning Australia, United Kingdom, Europe, CIS and Africa. During his career Mr. West has held senior positions at Horwath Chartered Accountants, PricewaterhouseCoopers and Barclays Capital. Mr West is currently non-executive chairman of ASX listed Zeta Petroleum plc (oil and gas exploration and production company).

Interest in Shares and Options

As at the date of this report, Mr West holds 1,377,544 shares, 100,000 options with an exercise price of A$2.40 and an expiry date of 3 June 2019, 200,000 options with an exercise price of NOK 4.00 and an expiry date of 28 April 2020, 270,000 options with an exercise price of NOK 1.70 and an expiry date of 15 November 2020, 1,000,000 options with an exercise price of NOK 1.70 and an expiry date of 22 December 2020, 1,500,000 options with an exercise price of NOK 7.75 and an expiry date of 31 May 2022 and 1,500,000 options with an exercise price of NOK 1.60 and an expiry date of 31 May 2023. Mr West's shares and some of the options are held in the name of Cresthaven Investments Pty Ltd, a company in which Mr West has an indirect beneficial interest.

Bjarne Moe — Non-Executive Director

Qualifications

Degree in Economics from the University of Oslo

Experience

Mr Moe has more than 35 years experience in the oil and gas sector. He started out in the Norwegian Ministry of Industry and was transferred to the Ministry of Petroleum and Energy when it was established in 1978. In 1988, Mr Moe was appointed Director General and head of the Oil and Gas department. Furthermore, Mr Moe has been a diplomat working for the Ministry of Foreign Affairs and been counsellor at the Norwegian embassy in Washington, D.C. and Mr Moe has further chaired several international commissions for solving questions regarding median line fields, and international gas and oil pipelines. He has also been heading delegations outside of Norway to solve specific questions and been a mediator for unitisation of fields etc. Mr Moe has headed several delegations for OECD (IEA) and has been a member of the Petroleum Price board for 15 years.

Mr. Moe is currently chairman of Consultor Energy AS, an energy advisory company.

Interest in Shares and Options

As at the date of this report, Mr Moe holds 10,000 shares, 50,000 options with an exercise price of NOK 4.00 and an expiry date of 28 April 2020, 200,000 options with an exercise price of NOK 1.70 and an expiry date of 22 December 2020, 200,000 options with an exercise price of NOK 7.75 and an expiry date of 31 May 2022 and 200,000 options with an exercise price of NOK 1.60 and an expiry date of 31 May 2023.

Timothy Turner — Non-Executive Director

Qualifications

B.Bus, FCPA, CTA, Registered Company Auditor.

Experience

Mr Turner is senior partner and founding partner of the Australian accounting firm, HTG Partners. Mr Turner specialises in domestic business structuring, corporate and trust tax planning and the issuing of audit opinions. Mr. Turner has 25 years experience in new ventures, capital raisings and general business consultancy, in addition to 15 years of experience in ASX listed junior resource based exploration companies. Mr Turner is a non-executive director of ASX listed Cape Lambert Resources Limited and a non-executive director of NSX listed International Petroleum Limited.

Interest in Shares and Options

As at the date of this report, Mr Turner has an interest in 4,167 fully paid ordinary shares and 200,000 options with an exercise price of NOK 7.75 and an expiry date of 31 May 2022 and 200,000 options with an exercise price of NOK 1.60 and an expiry date of 31 May 2023.

Anthony Wilson — Non-Executive Director (resigned 12 April 2018)

Qualifications

Fellow of the Institute of Chartered Accountants in England and Wales, and Fellow of the Chartered Institute for Securities and Investment.

Interest in Shares and Options

As at the date of his resignation, Mr Wilson held 10,000 shares, 50,000 options with an exercise price of NOK 4.00 and an expiry date of 3 June 2019, 200,000 options with an exercise price of NOK 1.70 and an expiry date of 22 December 2020 and 200,000 options with an exercise price of NOK 7.75 and an expiry date of 31 May 2022.

Company Secretary

Angeline Hicks is a Chartered Accountant with global corporate and financial experience. After gaining her qualifications at Deloitte, Ms Hicks furthered her career in the banking industry in London for eight years, working for investment banks such as Barclays Capital, Credit Suisse and JP Morgan, focusing on managing compliance and corporate and financial reporting. Ms Hicks is an Associate of the Governance Institute of Australia and also performs the role of Company Secretary for companies listed on the Australian Securities Exchange and the National Stock Exchange.

Meetings of Directors

The number of Directors' meetings (including Committees) held during the period each Director held office during the financial year and the number of meetings attended by each Director is:

	Directors' Meetings		Audit Committee Meetings	
Director	Eligible to attend	Attended	Eligible to attend	Attended
David King	2	2	1	1
Anders Bjarne Moe	2	2	1	1
Jens Pace	2	2	-	-
Timothy Turner	2	2	1	1
Stephen West	2	2	-	-
Anthony Wilson	1	-	-	-

In addition to meetings of Directors held during the year, due to the number and diversified location of the Directors, a number of matters are authorised by the Board of Directors via circulating resolutions. During the current year, three circulating resolutions were authorised by the Board of Directors. There were no Remuneration Committee or Continuous Disclosure Committee meetings during the year, as any relevant matters were discussed during the Directors' Meetings.

Indemnifying Directors and Officers

In accordance with the constitution, except as may be prohibited by the Corporations Act 2001, every Director, principal executive officer or secretary of the Company shall be indemnified out of the property of the Company against any liability incurred by him in his capacity as Director, principal executive officer or secretary of the Company or any related corporation in respect of any act or omission whatsoever and howsoever occurring or in defending any proceedings, whether civil or criminal.

Indemnification of Auditors

To the extent permitted by law, the Company has agreed to indemnify its auditors, BDO Audit (WA) Pty Ltd ("BDO"), as part of the terms of its audit engagement agreement against claims by third parties arising from the audit (for an unspecified amount). No payment has been made to indemnify BDO during or since the financial year.

Options

Unissued shares under option

At the date of this report unissued ordinary shares of the Company under option are:

Expiry Date	Exercise Price	US$ equivalent Exercise Price at 31 December 2018	Number Under Option
22 April 2019	A$3.00	US$ 2.12	17,501
3 June 2019	A$ 2.40	US$ 1.69	150,000
5 June 2019	A$3.00	US$ 2.12	20,000
15 December 2019	A$3.00	US$ 2.12	16,667
28 April 2020	NOK 4.00	US$ 0.46	1,627,000
15 November 2020	NOK 1.70	US$ 0.20	1,690,000
22 December 2020	NOK 1.70	US$ 0.20	2,900,000
11 January 2022	NOK 2.50	US$ 0.29	213,400
31 May 2022	NOK 7.75	US$ 0.89	6,526,070
2 Jan 2023	NOK 0.90	US$ 0.10	50,000
31 May 2023	NOK 1.60	US$ 0.18	5,900,000
Total			**19,110,638**

Shares issued on the exercise of options
During the current year, no ordinary shares were issued on the exercise of options (2017: 426,667).

Proceedings on behalf of Company
No person has applied for leave of Court to bring proceedings on behalf of the Company or intervene in any proceedings to which the Company is a party for the purpose of taking responsibility on behalf of the Company for all or any part of those proceedings.

The Company was not a party to any such proceedings during the year.

Auditor's independence declaration
The auditor's independence declaration for the year ended 31 December 2018 has been received and can be found on page 14 of the annual report.

Non-audit services
Non-audit services were provided by the entity's auditor's BDO, as per Note 6(d). The directors are satisfied that the provision of non-audit services is compatible with the general standard of independence for auditors imposed by the Corporations Act 2001. The nature and scope of each type of non-audit service provided means that auditor independence was not compromised.

This report is made in accordance with a resolution of the Board of Directors.

Jens Pace

Jens Pace
Director
Perth, 25 April 2019

Auditor's independence declaration

Declaration of independence by Phillip Murdoch to the Directors of African Petroleum Corporation Limited

As lead auditor of African Petroleum Corporation Limited for the year ended 31 December 2018, I declare that, to the best of my knowledge and belief, there have been:

1. No contraventions of the auditor independence requirements of the Corporations Act 2001 in relation to the audit; and

2. No contraventions of any applicable code of professional conduct in relation to the audit.

This declaration is in respect of African Petroleum Corporation Limited and the entities it controlled during the period.

Phillip Murdoch
Director

BDO Audit (WA) Pty Ltd
Perth, 25 April 2019

Corporate governance statement

The Board of Directors of African Petroleum Corporation Limited are responsible for establishing the corporate governance framework of the Company having regard to the Corporations Act 2001 (Cth) and applicable Listing Rules.

This corporate governance statement summarises the corporate governance practices adopted by the Company.

The current corporate governance plan is posted in a dedicated corporate governance information section of the Company's website at www.africanpetroleum.com.au

Summary of corporate governance practices

The Company's main corporate governance policies and practices are outlined below.

The Board of Directors

The Company's Board of Directors is responsible for overseeing the activities of the Company. The Board's primary responsibility is to oversee the Company's business activities and management for the benefit of the Company's shareholders.

The Board is responsible for the strategic direction, policies, practices, establishing goals for management and the operation of the Company.

The Board assumes the following responsibilities:
(a) appointment of the Chief Executive Officer and other senior executives and the determination of their terms and conditions including remuneration and termination;
(b) driving the strategic direction of the Company, ensuring appropriate resources are available to meet objectives and monitoring management's performance;
(c) reviewing and ratifying systems of risk management and internal compliance and control, codes of conduct and legal compliance;
(d) approving and monitoring the progress of major capital expenditure, capital management and significant acquisitions and divestitures;
(e) approving and monitoring the budget and the adequacy and integrity of financial and other reporting;
(f) approving the annual and half yearly accounts;
(g) approving significant changes to the organisational structure;
(h) approving the issue of any shares, options, equity instruments or other securities in the Company;
(i) ensuring a high standard of corporate governance practice and regulatory compliance and promoting ethical and responsible decision-making;
(j) recommending to shareholders the appointment of the external auditor as and when their appointment or reappointment is required to be approved by them; and
(k) meeting with the external auditor, at their request, without management being present.

Composition of the Board

Election of Board members is substantially the province of the shareholders in general meeting. However, subject thereto, the Company is committed to the following principles:
(a) the composition of the Board is to be reviewed regularly to ensure the appropriate mix of skills and expertise is present to facilitate successful strategic direction; and
(b) the principal criterion for the appointment of new Directors is their ability to contribute to the ongoing effectiveness of the Board, to exercise sound business judgement, to commit the necessary time to fulfil the requirements of the role effectively and to contribute to the development of the strategic direction of the Company.

The skills, experience and expertise relevant to the position of Director held by each Director in office at the date of the annual report is included in the Directors' report. The majority of the Board is to be comprised of Non-Executive Directors and where appropriate, at least 50% of the Board should be independent. Directors of the Company are considered to be independent when they are a Non-Executive Director (i.e. not a member of management and have been for the preceding 3 years), hold less than 5% of the voting shares of the Company and are free of any business or other relationship that could materially interfere with, or could reasonably be perceived to materially interfere with, the independent exercise of their judgement. In accordance with this definition, Mr J. Pace and Mr. S West are not considered independent.

Non-Executive Chairman Dr D King and Non-Executive Directors Mr B. Moe, Mr T Turner and Mr A. Wilson were considered to have been independent throughout the year, since their appointment or until their resignation (as applicable).

The term in office held by each Director in office at the date of this report is as follows:

D. King	5 years 6 months	Chairman	
B. Moe	4 years 6 months	Non-Executive Director	
J. Pace	3 years 5 months	Executive Director	
T. Turner	11 years 9 months	Non-Executive Director	
S. West	3 years 5 months	Executive Director	
A. Wilson	7 years 10 months	Non-Executive Director	(Resigned 12 April 2018)

There are procedures in place, agreed by the Board, to enable Directors, in furtherance of their duties, to seek independent professional advice at the Company's expense.

Corporate governance statement continued

Remuneration arrangements

Review of the Company's remuneration policy is delegated to the Remuneration Committee.

The total maximum remuneration of Non-Executive Directors, which may only be varied by shareholders in general meeting, is an aggregate amount of US$634,852 (A$900,000) per annum. The Board may award additional remuneration to Non-Executive Directors called upon to perform extra services or make special exertions on behalf of the Company.

Performance

Review of the performance of the Board is delegated to the Nomination Committee.

The Board have established formal practices to evaluate the performance of the Board, committees, Non-Executive Directors, the Chief Executive Officer, and senior management. Details of these practices are described in the Corporate Governance Plan available on the Company's website. No formal performance evaluation of the Board or individual Directors took place during the year.

Code of conduct

The Company has in place a code of conduct which aims to encourage appropriate standards of behaviour for Directors, officers, employees and contractors. All are expected to act with integrity and objectivity, striving at all times to enhance the reputation and performance of the Company. The Directors are subject to additional code of conduct requirements which includes highlighting situations which may constitute a conflict of interest for Directors. Directors have a responsibility to avoid any conflict from arising that could compromise their ability to perform their duties impartially. Any actual or potential conflicts of interest must be reported to the Board or superior.

Consolidated statement of comprehensive income

	Note	For the Year Ended 31 December 2018 US$	31 December 2017 US$
Continuing operations			
Revenue	6(a)	**12**	228,692
Exploration and evaluation expenditure		**82,414**	(9,856,447)
Impairment of exploration and evaluation expenditure	11	**(1,704,155)**	(18,367,865)
Consulting expenses		**(3,388,239)**	(1,423,965)
Compliance and regulatory expenses		**(122,754)**	(242,759)
Administration expenses		**(497,451)**	(572,101)
Employee benefits	6(c)	**(2,655,457)**	(4,387,472)
Travel expenses		**(160,537)**	(476,776)
Depreciation and amortisation expense		**(4,539)**	(3,387)
Net unrealised gains on fair value of financial liabilities		**-**	77,645
Foreign exchange gain		**38,544**	4,883
Loss from continuing operations before income tax		**(8,412,162)**	(35,019,552)
Income tax expense	5	**-**	-
Loss for the year from continuing operations		**(8,412,162)**	(35,019,552)
Other comprehensive losses			
Items that may be reclassified to profit or loss:			
Foreign currency translation reserve			
Foreign exchange loss on translation of functional currency to presentation currency		**(77,102)**	(33,930)
Other comprehensive losses for the year, net of tax		**(77,102)**	(33,930)
Total comprehensive loss for the year		**(8,489,264)**	(35,053,482)
Loss for the year is attributable to:			
Non-controlling interest		**(68,175)**	(399,488)
Owners of the parent		**(8,343,987)**	(34,620,064)
		(8,412,162)	(35,019,552)
Total comprehensive loss for the year is attributable to:			
Non-controlling interest		**(68,175)**	(399,488)
Owners of the parent		**(8,421,089)**	(34,653,995)
		(8,489,264)	(35,053,482)
Loss per share attributable to members			
Basic and diluted loss per share	21	**(5.37) cents**	(24.86) cents

The accompanying notes form part of these financial statements.

FINANCIAL STATEMENTS

Consolidated statement of financial position

	Note	As at 31 December 2018 US$	As at 31 December 2017 US$
Assets			
Current assets			
Cash and cash equivalents	7	**6,286,407**	13,186,482
Trade and other receivables	8	**119,915**	113,844
Restricted cash	9	**902,937**	902,937
Prepayments		**22,919**	125,748
Total current assets		**7,332,178**	14,329,011
Non-current assets			
Inventories		**–**	1,006,908
Property, plant and equipment	10	**7,100**	3,743
Exploration and evaluation expenditure	11	**–**	9,107,859
Total non-current assets		**7,100**	10,118,510
Total assets		**7,339,278**	24,447,521
Liabilities			
Current liabilities			
Trade and other payables	12	**3,839,524**	13,288,671
Total current liabilities		**3,839,524**	13,288,671
Total liabilities		**3,839,524**	13,288,671
Net assets		**3,499,754**	11,158,850
Equity			
Issued capital[1]	13	**642,740,272**	642,740,272
Reserves[1]	14	**22,704,013**	21,950,947
Accumulated losses		**(658,430,669)**	(650,086,682)
Parent interests		**7,013,616**	14,604,537
Non-controlling interests	15	**(3,513,862)**	(3,445,687)
Total equity		**3,499,754**	11,158,850

1 The comparative figures have been restated, the adjustments were not considered material.

The accompanying notes form part of these financial statements.

Consolidated statement of changes in equity

	Note	Issued capital US$	Share-based payment reserve US$	Foreign currency translation reserve US$	Accumulated losses US$	Non-controlling interest US$	Total US$
Balance at 1 January 2018		**642,740,272**	**34,182,365**	**(12,231,418)**	**(650,086,682)**	**(3,445,687)**	**11,158,850**
Loss for the year	14	–	–	–	**(8,343,987)**	**(68,175)**	**(8,412,162)**
Other comprehensive income: Foreign currency exchange differences arising on translation from functional currency to presentation currency		–	–	(77,102)	–	–	(77,102)
Total comprehensive loss for the year		–	–	(77,102)	(8,343,987)	(68,175)	(8,489,264)
Share-based payments	16	–	830,168	–	–	–	830,168
Balance at 31 December 2018		**642,740,272**	**35,012,533**	**(12,308,520)**	**(658,430,669)**	**(3,513,862)**	**3,499,754**
For the year ended 31 December 2017							
Balance at 1 January 2017		611,455,218	31,579,327	(12,197,488)	(615,466,618)	(3,046,199)	12,324,240
Loss for the year	14	–	–	–	(34,620,064)	(399,488)	(35,019,552)
Other comprehensive income		–	–	(33,930)	–	–	(33,930)
Total comprehensive loss for the year		–	–	(33,930)	(34,620,064)	(399,488)	(35,053,482)
Issue of capital[1]	13	31,093,816	–	–	–	–	31,093,816
Exercise of share options	13	191,238	–	–	–	–	191,238
Share-based payments[1]	16	–	2,603,038	–	–	–	2,603,038
Balance at 31 December 2017[1]		642,740,272	34,182,365	(12,231,418)	(650,086,682)	(3,445,687)	11,158,850

1 The comparative figures have been restated, the adjustments were not considered material.

The accompanying notes form part of these financial statements.

Consolidated statement of cash flows

	Note	For the Year Ended 31 December 2018 US$	31 December 2017 US$
Cash flows from operating activities			
Payments to suppliers and employees		**(6,533,682)**	(22,200,485)
Interest received		**12**	9
Finance costs		**(16,560)**	(29,322)
Other income		**-**	197,804
Net cash flows used in operating activities	7	**(6,550,230)**	(22,031,994)
Cash flows from investing activities			
Proceeds from sale of plant and equipment		**-**	30,879
Payment for plant and equipment		**(7,896)**	(3,026)
Payment for exploration and evaluation activities		**(303,394)**	(1,037,835)
Cash backing security returned		**-**	4,375,000
Cash backing security provided		**-**	(333,844)
Net cash from investing activities		**(311,290)**	3,031,174
Cash flows from financing activities			
Proceeds from issue of shares		**-**	33,644,423
Capital raising costs		**-**	(1,852,606)
Proceeds from exercise of share options		**-**	191,238
Net cash from financing activities		**-**	31,983,055
Net increase/(decrease) in cash and cash equivalents		**(6,861,520)**	12,982,235
Cash and cash equivalents at the beginning of the year		**13,186,482**	233,298
Net foreign exchange differences		**(38,555)**	(29,051)
Cash and cash equivalents at the end of year	7	**6,286,407**	13,186,482

The accompanying notes form part of these financial statements.

Notes to the consolidated financial statements

1. Corporate information
The financial report of the Company and its subsidiaries (together the "Group") for the year ended 31 December 2018 was authorised for issue in accordance with a resolution of the Directors on 25 April 2019.

African Petroleum Corporation Limited is a "for profit entity" and is a company limited by shares incorporated in Australia. Its shares are publicly traded on the Oslo Axess (code: APCL), a regulated market place of the Oslo Stock Exchange, Norway. Details of the principal activities are included in the Director's Report.

2. Basis of preparation of annual report
The financial report is a general purpose financial report, which has been prepared in accordance with the requirements of the Corporations Act 2001, Australian Accounting Standards and other authoritative pronouncements of the Australian Accounting Standards Board. The financial report has been prepared on a historical cost basis except for the derivative financial liability, which has been measured at fair value.

The financial report is presented in United States Dollars and all values are rounded to the nearest dollar unless otherwise stated.

Compliance statement
The financial report complies with Australian Accounting Standards. The financial report also complies with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board.

Going concern
As at 31 December 2018, the Group had net current assets of US$3,492,654 (31 December 2017: US$1,040,340), which includes cash and cash equivalents of US$6,286,407 (31 December 2017: US$13,186,482), and trade and other payables US$3,839,524 (31 December 2017: US$13,288,671).

As at 31 December 2018, trade and other payables included US$1,911,084 for licence commitments in relation to licences that are currently in arbitration. Although disclosed within the financial statements as current liabilities due to the contractual terms of the agreements, Management do not expect to extinguish these liabilities until the arbitration process is successfully completed. The arbitration processes are forecast to take longer than 12 months. The restricted cash balance of US$902,937, can only be utilised towards settlement of these liabilities.

As at the date of the approval, the only active operations of the Group are the ongoing arbitration matters in Senegal and The Gambia. There is significant uncertainty regarding the working capital necessary for the arbitration processes, and the proposed transaction with PetroNor has yet to be complete. The Group's ability to continue as a going concern is dependent on raising further capital.

These conditions indicate the existence of a material uncertainty, which may cast significant doubt over the Group's ability to continue as a going concern, and, therefore, it may be unable to realise its assets and discharge its liabilities in the normal course of business.

Management has several options within its control to mitigate the risk of going concern, including obtaining litigation funding, implementing a reduction of discretionary overheads, completing a transaction such as the transaction proposed with PetroNor, or undertaking an equity raising. Management's preferred option is the proposed transaction with PetroNor as detailed in Note 24. The Transaction was announced by the Company on 19 March 2019 and will significantly change the working capital requirements of the business, plus provide access to additional management skills and cash flow resources.

Management and the Directors are satisfied there are reasonable grounds to believe that the Group will be able to continue as a going concern. The financial statements have been prepared on a going concern basis which contemplates the continuity of normal business activities and the realisation of assets and the settlement of liabilities in the ordinary course of business

Should the Group not be able to continue as a going concern, it may be required to realise its assets and discharge its liabilities other than in the ordinary course of business. The financial report does not include any adjustments relating to the recoverability and classification of recorded asset amounts or liabilities that might be necessary should the consolidated entity not continue as a going concern.

3. Summary of accounting policies
Accounting policies are selected and applied in a manner which ensures that the resulting financial information satisfies the concepts of relevance and reliability, thereby ensuring that the substance of the underlying transactions or other events is reported.

The following is a summary of the material accounting policies adopted by the Group in the preparation of the financial report. The accounting policies have been consistently applied, unless otherwise stated.

(a) New Accounting Standards and Interpretations
New Accounting Standards and Interpretations effective 1 January 2018

The Group has adopted all new and amended Australian Accounting Standards and Interpretations effective as of 1 January 2018. The application of these Accounting Standards and Interpretations had no material impact on the Group.

Notes to the consolidated financial statements continued

3. Summary of accounting policies continued

(b) Consolidation

The consolidated financial statements comprise the financial statements of African Petroleum Corporation Limited ("the Company") and its subsidiaries for the year ended 31 December 2018 (together the Group).

Control is achieved when the Group is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. Specifically, the Group controls an investee if and only if the Group has:
- power over the investee (i.e. existing rights that give it the current ability to direct the relevant activities of the investee);
- exposure, or rights, to variable returns from its involvement with the investee; and
- the ability to use its power over the investee to affect its returns.

When the Group has less than a majority of the voting or similar rights of an investee, the Group considers all relevant facts and circumstances in assessing whether it has power over an investee, including:
- The contractual arrangement with the other vote holders of the investee.
- Rights arising from other contractual arrangements.
- The Group's voting rights and potential voting rights.

The Group reassesses whether or not it controls an investee if facts and circumstances indicate that there are changes to one or more of the three elements of control. Consolidation of a subsidiary begins when the Group obtains control over the subsidiary and ceases when the Group loses control of the subsidiary. Assets, liabilities, income and expenses of a subsidiary acquired or disposed of during the year are included in the statement of comprehensive income from the date the Group gains control until the date the Group ceases to control the subsidiary.

Profit or loss and each component of other comprehensive income (OCI) are attributed to the equity holders of the parent of the Group and to the non-controlling interests, even if this results in the non-controlling interests having a deficit balance. When necessary, adjustments are made to the financial statements of subsidiaries to bring their accounting policies into line with the Group's accounting policies. All intra-group assets and liabilities, equity, income, expenses and cash flows relating to transactions between members of the Group are eliminated in full on consolidation.

A change in the ownership interest of a subsidiary, without a loss of control, is accounted for as an equity transaction. If the Group loses control over a subsidiary, it:
- De-recognises the assets (including goodwill) and liabilities of the subsidiary.
- De-recognises the carrying amount of any non-controlling interests.
- De-recognises the cumulative translation differences recorded in equity.
- Recognises the fair value of the consideration received.
- Recognises the fair value of any investment retained.
- Recognises any surplus or deficit in profit or loss.
- Reclassifies the parent's share of components previously recognised in OCI to profit or loss or retained earnings, as appropriate, as would be required if the Group had directly disposed of the related assets or liabilities.

(c) Segment reporting

An operating segment is a component of an entity that engages in business activities from which it may earn revenues and incur expenses (including revenues and expenses relating to transactions with other components of the same entity), whose operating results are regularly reviewed by the entity's chief operating decision makers to make decisions about resources to be allocated to the segments and assess their performance and for which discrete financial information is available. This includes start-up operations which are yet to earn revenues.

Operating segments have been identified based on the information available to chief operating decision makers – being the Board and the executive management team.

Operating segments that meet the quantitative criteria as prescribed by AASB 8 are reported separately. However, an operating segment that does not meet the quantitative criteria is still reported separately where information about the segment would be useful to users of the financial statements.

Information about other business activities and operating segments that are below the quantitative criteria are combined and disclosed in a separate category called "all other segments".

(d) Foreign currency translation

Functional and presentation currency

The Company has elected to use United States Dollars, being the functional currency of all major subsidiaries in the Group, as its presentation currency. Where the functional currencies of entities within the consolidated Group differ from United States Dollars, they have been translated into United States Dollars. The functional currency of African Petroleum Corporation Limited is Australian Dollars.

Transactions and balances
Transactions in foreign currencies are initially recorded in the functional currency by applying the exchange rates ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the rate of exchange ruling at the reporting date and any gains or losses are recognised in the income statement.

Non-monetary items that are measured in terms of historical cost in the foreign currency are translated using the exchange rate as at the date of the initial transaction. Non-monetary items measured at fair value in a foreign currency are translated using the exchange rates at the date when the fair value was determined.

Translation of Group Companies' functional currency to presentation currency
On consolidation, the assets and liabilities of foreign operations are translated into United States Dollars at the rate of exchange prevailing at the reporting date and their income and expenditure are translated at exchange rates prevailing at the dates of the transactions. The exchange differences arising on translation for consolidation are recognised in other comprehensive income. On disposal of a foreign operation, the component of other comprehensive income relating to that particular foreign operation is recognised in profit or loss.

(e) Cash and cash equivalents
Cash and cash equivalents include cash on hand, deposits held at call with banks, other short-term highly liquid investments with original maturities of three months or less, and bank overdrafts. Bank overdrafts are shown within short-term borrowings in current liabilities on the Statement of Financial Position.

(f) Trade receivables
Trade receivables are amounts due from customers for goods sold or services performed in the ordinary course of business. They are generally due for settlement within 30 days and therefore are all classified as current. Trade receivables are recognised initially at the amount of consideration that is unconditional unless they contain significant financing components, when they are recognised at fair value. The Group holds the trade receivables with the objective to collect the contractual cash flows and therefore measures them subsequently at amortised cost using the effective interest method.

Trade receivables are written off when there is no reasonable expectation of recovery. Indicators that there is no reasonable expectation of recovery include, amongst others, the failure of a debtor to engage in a repayment plan with the Group, and a failure to make contractual payments for a period of greater than 120 days past due.

Impairment losses on trade receivables and contract assets are presented as net impairment losses within operating profit. Subsequent recoveries of amounts previously written off are credited against the same line item.

(g) Exploration and evaluation expenditure
Exploration and evaluation activity involves the search for hydrocarbon resources, the determination of technical feasibility and the assessment of commercial viability of an identified resource. For each area of interest, expenditure incurred in the acquisition of rights to explore and all costs directly associated with holding the licence such as rental, training and corporate and social responsibility are capitalised as exploration and evaluation intangible assets. Signature bonuses required by licence agreements are capitalised as exploration and evaluation intangible assets. Other costs directly associated with the licence are expensed as incurred.

Exploration, evaluation and development expenditure is recorded at historical cost and allocated to cost pools on an area of interest. Expenditure on an area of interest is capitalised and carried forward where rights to tenure of the area of interest are current and:
i. it is expected to be recouped through successful development and exploitation of the area of interest or alternatively by its sale; or
ii. exploration and evaluation activities are continuing in an area of interest but at reporting date have not yet reached a stage which permits a reasonable assessment of the existence or otherwise of economically recoverable reserves.

Accumulated costs in respect of areas of interest which are abandoned are written off in full against profit in the period in which the decision to abandon the area is made.

Projects are advanced to development status when it is expected that further expenditure can be recouped through sale or successful development and exploitation of the area of interest.

All capitalised costs are subject to commercial and management review, as well as review for indicators of impairment at least once a year. This is to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off through the statement of profit or loss and other comprehensive income.

When proved reserves of oil and natural gas are identified and development is sanctioned by management, the relevant capitalised expenditure is first assessed for impairment and (if required) any impairment loss is recognised, then the remaining balance is transferred to oil and gas properties.

Proceeds from disposal or farm-out transactions of intangible exploration assets are used to reduce the carrying amount of the assets. When proceeds exceed the carrying amount, the difference is recognised as a gain. When the Group disposes of its full interests, gains or losses are recognised in accordance with the policy for recognising gains or losses on sale of plant, property and equipment.

Notes to the consolidated financial statements continued

3. Summary of accounting policies continued

(h) Revenue

Revenue from contracts with customers is recognised when control of the goods and services are transferred to the customer at an amount that reflects the consideration to which the Group expects to be entitled in exchange for those goods or services.

Interest

Interest revenue is recognised on a time proportional basis using the effective interest method. This is a method of calculating the amortised cost of a financial asset and allocating the interest income over the relevant period using the effective interest rate, which is the rate that exactly discounts the estimated future cash receipts through the expected useful life of the financial asset to the net carrying amount of the financial asset.

(i) Income tax

The income tax expense or revenue for the period is the tax payable on the current period's taxable income based on the relevant national income tax rate adjusted by changes in deferred tax assets and liabilities attributable to temporary differences between the tax bases of assets and liabilities and their carrying amounts in the financial statements, and to unused tax losses.

Deferred tax assets and liabilities are recognised for temporary differences at the tax rates expected to apply when the assets are recovered or liabilities are settled, based on those tax rates which are enacted or substantively enacted for each jurisdiction. The relevant tax rates are applied to the cumulative amounts of deductible and taxable temporary differences to measure the deferred tax asset or liability. An exception is made for certain temporary differences arising from the initial recognition of an asset or liability. No deferred tax asset or liability is recognised in relation to these temporary differences if they arose in a transaction, other than a business combination, that at the time of the transaction did not affect either accounting profit or taxable profit or loss.

Deferred tax assets are recognised for deductible temporary differences and unused tax losses only if it is probable that future taxable amounts will be available to utilise those temporary differences and losses.

Current and deferred tax balances attributable to amounts recognised directly in equity are also recognised directly in equity.

(j) Employee benefits

Provision is made for benefits accruing to employees in respect of wages and salaries, annual leave and long service leave when it is probable that settlement will be required and they are capable of being measured reliably.

Provisions made in respect of employee benefits expected to be settled within 12 months are measured at their nominal values using the remuneration rate expected to apply at the time of settlement.

Provisions made in respect of employee benefits, which are not due to be settled within 12 months are determined using the projected unit credit method.

(k) Trade and other payables

Trade and other payables are carried at amortised cost and due to their short-term nature they are not discounted.

(l) Provisions

Provisions are recognised when the Group has a present obligation, the future sacrifice of economic benefits is probable, and the amount of the provision can be measured reliably. Any present obligations where the payment is deemed less than probable but not remote have been disclosed as a contingent liability.

Costs of site restoration are provided from when exploration commences and are included in the costs of that stage. Site restoration costs include the dismantling and removal of mining plant, equipment and building structures, waste removal, and rehabilitation of the site in accordance with clauses of the licences or production sharing contracts. Such costs have been determined using estimates of future costs, current legal requirements and technology on a discounted basis.

Any changes in the estimates for the costs are accounted on a prospective basis. In determining the costs of site restoration, there is uncertainty regarding the nature and extent of the restoration due to community expectations and future legislation.

(m) Share capital

Contributed equity is recognised at the fair value of the consideration received by the Group, less any capital raising costs in relation to the issue.

Incremental costs directly attributable to the issue of new shares or options are shown in equity as a deduction, net of tax, from the proceeds.

(n) Share-based payments

The fair value of shares awarded is measured at the share price on the date the shares are granted. For options awarded, the fair value is measured at grant date using the Black-Scholes model. Shares and options which are subject to vesting conditions, are recognised over the estimated vesting period during which the holder becomes unconditionally entitled to the shares or options.

When the terms of an equity-settled award are modified, the minimum expense recognised is the expense had the terms had not been modified, if the original terms of the award are met. An additional expense is recognised for any modification that increases the total fair value of the share-based payment transaction, or is otherwise beneficial to the employee as measured at the date of modification.

(o) Financial instruments

A financial instrument is any contract that gives rise to a financial asset of any one entity and a financial liability or equity instrument of another entity.

i) Financial assets

Financial assets are classified, at initial recognition, as subsequently measured at amortised cost, fair value through other comprehensive income (OCI), and fair value through profit or loss, as appropriate.

The classification of financial assets at initial recognition depends on the financial asset's contractual cash flow characteristics and the Group's business model for managing them. With the exception of trade receivables that do not contain a significant financing component or for which the Group has applied the practical expedient, the Group initially measures a financial asset at its fair value plus, in the case of financial assets not subsequently measured at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.

In order for a financial asset to be classified and measured at amortised cost or fair value through OCI, it needs to give rise to cash flows that are "solely payments of principal and interest (SPPI)" on the principal amount outstanding. This assessment is referred to as the SPPI test and is performed at an instrument level.

The Group's business model for managing financial assets refers to how it manages its financial assets in order to generate cash flows. The business model determines whether cash flows will result from collecting contractual cash flows, selling the financial assets, or both.

Purchases or sales of financial assets that require delivery of assets within a time frame established by regulation or convention in the market place (regular way trades) are recognised on the trade date, i.e., the date that the Group commits to purchase or sell the asset.

Subsequent measurement

For purposes of subsequent measurement, financial assets are classified in four categories:

- Financial assets at amortised cost (debt instruments).
- Financial assets at fair value through OCI with recycling of cumulative gains and losses (debt instruments).
- Financial assets designated at fair value through OCI with no recycling of cumulative gains and losses upon derecognition (equity instruments).
- Financial assets at fair value through profit or loss.

The Group has not designated any financial assets at fair value through profit or loss.

Financial assets at amortised cost (debt instruments)

The Group measures financial assets at amortised cost if both of the following conditions are met:

- The financial asset is held within a business model with the objective to hold financial assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Financial assets at amortised cost are subsequently measured using the effective interest (EIR) method and are subject to impairment. Gains and losses are recognised in profit or loss when the asset is derecognised, modified or impaired.

Impairment of financial assets

The Group recognises an allowance for expected credit losses (ECLs) for all debt instruments not held at fair value through profit or loss. ECLs are based on the difference between the contractual cash flows due in accordance with the contract and all the cash flows that the Group expects to receive, discounted at an approximation of the original effective interest rate. The expected cash flows will include cash flows from the sale of collateral held or other credit enhancements that are integral to the contractual terms.

ECLs are recognised in two stages. For credit exposures for which there has not been a significant increase in credit risk since initial recognition, ECLs are provided for credit losses that result from default events that are possible within the next 12 months (a 12-month ECL). For those credit exposures for which there has been a significant increase in credit risk since initial recognition, a loss allowance is required for credit losses expected over the remaining life of the exposure, irrespective of the timing of the default (a lifetime ECL).

For trade receivables and contract assets, the Group applies a simplified approach in calculating ECLs. Therefore, the Group does not track changes in credit risk, but instead recognises a loss allowance based on lifetime ECLs at each reporting date. The Group has established a provision matrix that is based on its historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment.

The Group considers a financial asset in default when contractual payments are 90 days past due. However, in certain cases, the Group may also consider a financial asset to be in default when internal or external information indicates that the Group is unlikely to receive the outstanding contractual amounts in full before taking into account any credit enhancements held by the Group. A financial asset is written off when there is no reasonable expectation of recovering the contractual cash flows.

ii) Financial liabilities

Financial liabilities are classified, at initial recognition, as financial liabilities at fair value through profit or loss, loans and borrowings, payables, or as derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial liabilities are recognised initially at fair value and, in the case of loans and borrowings and payables, net of directly attributable transaction costs.

The Group's financial liabilities include trade and other payables, loans and borrowing, including bank overdrafts, financial guarantee contracts, and derivative financial instruments.

Notes to the consolidated financial statements continued

3. Summary of accounting policies continued

Subsequent measurement

The measurement of financial liabilities depends on their classification, as described below:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss include derivative financial liabilities, financial liabilities held for trading and financial liabilities designated upon initial recognition as at fair value through profit or loss.

Financial liabilities are classified as held for trading if they are incurred for the purpose of repurchasing in the near term. This category also includes derivative financial instruments entered into by the Group that are not designated as hedging instruments in hedge relationships as defined by AASB 9. Separated embedded derivatives are also classified as held for trading unless they are designated as effective hedging instruments.

Gains or losses on liabilities held for trading are recognised in the statement of profit or loss.

Financial liabilities designated upon initial recognition at fair value through profit or loss are designated at the initial date of recognition, and only if the criteria in AASB 9 are satisfied.

Loans and borrowings

After initial recognition, interest-bearing loans and borrowings are subsequently measured at amortised cost using the effective interest rate ("EIR") method. Gains and losses are recognised in profit or loss when the liabilities are derecognised as well as through the EIR amortisation process.

Amortised cost is calculated by taking into account any discount or premium on acquisition and fees or costs that are an integral part of the EIR. The EIR amortisation is included as finance costs in the statement of profit or loss.

This category generally applies to interest-bearing loans and borrowings.

Derecognition

A financial liability is derecognised when the obligation under the liability is discharged or cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as the derecognition of the original liability and the recognition of a new liability. The difference in the respective carrying amounts is recognised in the statement of profit or loss.

iii) Offsetting of financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated statement of financial position if there is a currently enforceable legal right to offset the recognised amounts and there is an intention to settle on a net basis, to realise the assets and settle the liabilities simultaneously.

(p) Joint arrangements

Joint arrangements are arrangements of which two or more parties have joint control. Joint control is the contractual agreed sharing of control of the arrangement which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control. Joint arrangements are classified as either a joint operation or joint venture, based on the rights and obligations arising from the contractual obligations between the parties to the arrangement.

To the extent the joint arrangement provides the Company with rights to the individual assets and obligations arising from the joint arrangement, the arrangement is classified as a joint operation and as such, the Company recognises its:

- assets, including its share of any assets held jointly;
- liabilities, including its share of any liabilities incurred jointly;
- revenue from the sale of its share of the output arising from the joint operation;
- share of revenue from the sale of the output by the joint operation; and
- expenses, including its share of any expenses incurred jointly.

To the extent the joint arrangement provides the Company with rights to the net assets of the arrangement, the investment is classified as a joint venture and accounted for using the equity method. Under the equity method, the cost of the investment is adjusted by the post-acquisition changes in the Company's share of the net assets of the venture.

4. Significant accounting judgements, estimates and assumptions

The Directors evaluate estimates and judgements incorporated in the financial report based on historical knowledge and best available current information. Estimates assume a reasonable expectation of future events and are based on current trends and economic data, obtained both externally and within the Group.

Management has identified the following critical accounting policies for which significant judgements, estimates and assumptions are made. Actual results may differ from these estimates under different assumptions and conditions and may materially affect financial results or the financial position reported in future period.

Further details of the nature of these assumptions and conditions may be found in the relevant notes to the financial statements.

Exploration and evaluation expenditure

Exploration and evaluation expenditure for each area of interest is carried forward as an asset provided certain conditions listed in Note 3(g) are met. Exploration and evaluation assets are assessed for impairment when facts and circumstances suggest that the carrying amount of an exploration and evaluation asset may exceed the recoverable amount. These calculations and reviews require the use of assumptions and judgement. In the case of impairment during the exploration and evaluation phase, fair value less cost to sell is used as the recoverable amount to determine an impairment allowance for exploration and evaluation expenditure assets because the value in use of the assets is nil. The related carrying amounts are disclosed in Note 11.

The value of the Group's interest in exploration expenditure is dependent upon:
- the continuance of the Group's rights to tenure of the areas of interest;
- the results of future exploration; and
- the recoupment of costs through successful development and exploitation of the areas of interest, or alternatively, by their sale.

Upon the farm-out of equity of an exploration licence, judgement is required when assessing the recognition of any consideration received. If past exploration and evaluation costs are reimbursed as part of the farm-out transaction, the consideration is pro-rated and matched against where the original exploration and evaluation costs have been recognised within the financial statements.

Where a licence has been relinquished management will make an assessment as to whether any accrued exploration costs are likely to be paid or whether all commitments have been met. Where an outflow of resources is no longer deemed probable on exit but possible a contingent liability will be disclosed. During the year management have made this assessment and derecognised a number of accrued liabilities and disclosed a contingent liability. See Notes 12 and 20 for more information.

Share-based payment transactions

The Group measures the cost of equity-settled transactions with employees, Directors and consultants by reference to the fair value of equity instruments at the date at which they are granted. The fair value of shares awarded is measured using the share price on the date the shares are granted. The fair value of options is determined on grant date using the Black-Scholes model. The related assumptions are detailed in Note 16. The accounting estimates and assumptions relating to equity-settled share-based payments would have no impact on the carrying amounts of assets and liabilities within the next annual reporting period but may impact expenses and equity.

Inventory valuation

The inventory accounting policy requires that the valuation is based on the Net Realisable Value and due to the reduced operations in the industry combined with the specialist nature of some items, there is not a readily active market to provide some valuations. For these items the valuation is based on management's judgement.

5. Income tax

	2018 US$	2017 US$
(a) The components of income tax expense comprise:		
Under provision in prior year	–	–
Current tax	–	–
(b) The prima facie tax on loss from continuing activities before income tax is reconciled to the income tax as follows:		
Prima facie tax benefit on loss from ordinary activities before income tax at 30% (31 December 2017: 30%)	**2,523,647**	10,505,866
Foreign tax rate adjustment	**(704,248)**	(3,307,080)
	1,819,399	7,198,786
Add/(less)		
Tax effect of		
– Tax effect of permanent differences	**(238,354)**	(4,322)
– Unrecognised deferred tax asset attributable to tax losses and temporary differences	**(1,581,045)**	(7,194,464)
Income tax expense/(benefit)	–	–

Deferred tax assets have not been brought to account in respect of tax losses and unrecognised capital allowances because as at 31 December 2018 it is uncertain when future taxable amounts will be available to utilise those temporary differences and losses. As at 31 December 2018, the carried forward gross tax loss is US$188 million (2017: US$601 million).

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Notes to the consolidated financial statements continued

6. Loss before income tax expense

	2018 US$	2017 US$
(a) Revenue		
Interest income	12	9
Other revenue	–	228,683
	12	228,692
(b) Expenses		
Depreciation and amortisation	4,539	3,387
Lease rental costs	261,315	301,746
Loss on disposal of property, plant and equipment	–	-
	265,854	305,133
(c) Employee remuneration		
Employee benefits	914,159	1,159,903
Director's remuneration	962,921	1,495,060
Share-based payments (refer to Note 16)	778,377	1,732,509
	2,655,457	4,387,472
(d) Remuneration of auditors		
Paid or payable to BDO		
Audit or review of financial reports		
BDO (WA) Pty Ltd	28,000	25,200
BDO related practices	42,000	112,800
	70,000	138,000
Other non-assurance services		
BDO related practices	39,417	15,340
	109,417	153,340
Paid or payable to other audit firms		
Other non-assurance services	20,382	7,019
	20,382	25,229

7. Cash and cash equivalents

		2018 US$	2017 US$
Cash at bank and on hand		6,286,407	13,186,482
Reconciliation of net loss to net cash flows from operating activities			
Loss from ordinary activities		(8,412,162)	(35,019,552)
Adjusted for non-cash items:			
Impairment of exploration and evaluation expenditure	11	1,704,155	19,012,665
Depreciation and loss on disposal of property, plant and equipment		4,539	3,387
Share-based payments		830,168	1,905,038
Net foreign exchange differences		(38,543)	(4,883)
(Gain)/loss on disposal of plant property and equipment	10	-	(30,879)
Fair value movement in financial liability		-	(75,218)
Changes in net assets and liabilities, net of effects from acquisition of business combination:			
Decrease in trade and other receivables		(11,099)	80,038
Decrease in trade and other payables	12	(627,288)	(7,902,590)
Net cash used in operating activities		(6,550,230)	(22,031,994)

8. Trade and other receivables

	2018 US$	2017 US$
Current		
Trade receivables	6,142	6,142
Other receivables	113,773	107,702
	119,915	113,844
Loan receivable from key management personnel[(a)]	1,501,354	1,590,587
Share-based payment liability	(1,501,354)	(1,590,587)
	–	–
Total trade and other receivables	119,915	113,844

(a) During 2012 and 2013, US$1,037,994 (£645,359) was loaned to former CEO Karl Thompson and US$630,497 (£390,321) was loaned to Jens Pace to cover tax payable on performance shares awarded to Mr Thompson and Mr Pace. The loans can only be used for the payment of the relevant tax (upon presentation of the tax amount) and must be repaid within 5 years or from the sale of any shares prior to this time. On 4th April 2018, the board agreed to extend the repayment date by a further 3 years. The shares are subject to a voluntary escrow, whereby the shares cannot be sold or transferred until the loans are discharged and the proceeds are to be applied to discharge the loans. During the period, no interest was charged, so no further impairment was necessary. In previous years, interest was charged on the loans at 4%. The loan agreements were approved by the Board of Directors as being on arm's length terms. If prior to the repayment date the proceeds from the sale of the performance shares are insufficient in total to cover the loans, the Company will waive the remaining balance of the loans. At 31 December 2018, the performance shares awarded to Mr Thompson have a market value of US$7,987 and the total limited recourse feature of the loan of US$935,878 (2017: US$991,502) has been recognised as a share-based payment liability. At 31 December 2018 the performance shares awarded to Mr Pace have a market value of US$2,227 and the total limited recourse feature of the loan of US$565,476 (2017: US$599,085) has been recognised as a share-based payment liability. During the year, the movement in the limited recourse feature of the loans is due to foreign exchange differences.

For terms and conditions relating to related party receivables, refer to Note 17.

As at 31 December, the ageing analysis of trade receivables is as follows:

	Total	Past Due but not Impaired				Past due and impaired
	US$	< 30 days	30-60 days	61-90 days	> 90 days	Specific
2018	**6,142**	–	–	–	**6,142**	–
2017	6,142	5,000	–	–	1,142	–

See Note 18 on credit risk, which describes how the Company manages and measures the credit quality of its receivables that are neither past due nor impaired.

Other receivables are neither past due or impaired.

9. Restricted cash

	2018 US$	2017 US$
Current		
Restricted cash	902,937	902,937

Restricted cash balances represent cash backed security provided in relation to the Company's obligations required under the exploration licences. The cash will be utilised for training and resources by mutual agreement with the relevant country's government authorities.

10. Property, plant and equipment

	2018 US$	2017 US$
Plant and Equipment		
Cost at beginning of the year	1,230,544	1,498,383
Additions at cost	7,896	3,026
Disposals	(762)	(270,865)
Cost at end of the year	1,237,678	1,230,544
Accumulated depreciation at beginning of the year	(1,226,801)	(1,494,279)
Depreciation expense	(4,539)	(3,387)
Depreciation on disposals	762	270,865
Accumulated depreciation at end of the year	(1,230,578)	(1,226,801)
Net book value at beginning of the year	3,743	4,104
Net book value at end of the year	7,100	3,743

Notes to the consolidated financial statements continued

11. Exploration and evaluation expenditure

i. Carrying value

	2018 US$	2017 US$
Opening balance	**9,107,859**	27,582,689
Exploration expenditure incurred	**303,394**	537,835
Impairment of exploration and evaluation expenditure[1,2,3,4]	**(9,411,253)**	(19,012,665)
	-	9,107,859

1 An impairment loss of US9,411,253 (2017: Nil) was recognised in respect of exploration and evaluation expenditure in Sierra Leone. This impairment loss amount was determined after consideration of several factors including ongoing discussions with potential partners, current tenure and future exploration commitments. The carrying value of exploration and evaluation of the affected area of interest was written-off to nil in the absence of future expected benefits.
2 An impairment loss of Nil (2017: US$8,550,000) was recognised in respect of exploration and evaluation expenditure in Cote d'Ivoire. This impairment loss amount was determined after consideration of several factors including ongoing discussions with potential partners, current tenure and future exploration commitments. The carrying value of exploration and evaluation of the affected area of interest was written-off to nil in the absence of future expected benefits.
3 An impairment loss of Nil (2017: US$10,462,665) was recognised in respect of exploration and evaluation expenditure in Senegal and The Gambia. This impairment loss amount was determined after consideration of several factors including ongoing discussions with potential partners, current tenure and future exploration commitments. The carrying value of exploration and evaluation of the affected area of interest was written-off to nil in the absence of future expected benefits.
4 Within the statement of comprehensive income, the impairment of evaluation and evaluation expense presents the loss recognised for the Sierra Leone assets net with the US$7,707,097 exploration licence commitments released from other payables as detailed in Note 12.

ii. Licence overview and risk

The Group's exploration and evaluation assets relate to the following licences:

Country	Licence	Carrying value as at 31 December 2018	Operator	Working interest	Grant date	End current phase	Area km²	Outstanding commitments in current phase
Senegal	Rufisque Offshore Profond	-	African Petroleum Senegal Limited	90%[4]	Oct 2011	Oct 2015[5]	10,357	One exploration well
Senegal	Senegal Offshore Sud Profond	-	African Petroleum Senegal Limited	90%[4]	Oct 2011	Dec 2017[6]	5,439	Further geoscience and one contingent exploration well
The Gambia	A1	-	African Petroleum Gambia Limited	100%[7]	Sep 2006	Sep 2016[8]	1,296	One exploration well to be drilled on either A1 or A4
The Gambia	A4	-	African Petroleum Gambia Limited	100%[7]	Sep 2006	Sep 2016[8]	1,376	See above

4 Société des Pétroles du Sénégal has an option to increase its 10% interest to 20% following exploitation authorisation.
5 The current phase of the ROP licence ended in October 2015; however, the Company has lodged a request for an extension with the Government of Senegal and under the terms of the licence, the block remains active until a termination procedure is enacted by the Republic of Senegal. To date, the Republic of Senegal has not validly enacted such termination procedure.
6 The current phase of the SOSP licence ended in December 2017; however, the Company lodged an application to enter the second renewal phase of the contract, and also requested to exchange the outstanding well commitment in the current phase for a 3D seismic acquisition programme and transfer this revised outstanding commitment to the second renewal phase.
7 The Gambia National Oil Company has an option to acquire a 10% participating interest in the Licence from the development stage.
8 The current phase of the A1 and A4 licences required the Company to drill an exploration well on either of the licences no later than 1 September 2016. The status of these licences is currently in arbitration managed by the International Centre for the Settlement of Investment Disputes ("ICSID").

Accounting estimates and judgements are continually evaluated and are based on other factors, including expectations of future events that are believed to be reasonable under the circumstances. The Group makes estimates and assumptions that have a significant risk of causing a material adjustment within the next financial year.

The most significant risk currently facing the Group in relation to the carrying value of exploration and evaluation expenditure is that it does not receive approval for its licence extensions and renegotiations for its Gambian and Senegalese projects.

Senegal

Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Senegal Licences and estimates the net unrisked mean prospective oil resources at 1,779MMStb.

The Gambia

Independent petroleum consultant ERC Equipoise prepared an assessment of prospective oil resources attributable to the Company's Gambian Licences and estimates the net unrisked mean prospective oil resources at 3,079MMStb.

12. Trade and other payables

	2018 US$	2017 US$
Trade payables[1]	**1,837,755**	3,495,837
Accruals	**786,433**	6,516,796
Other payables[2,3]	**1,215,336**	3,276,038
	3,839,524	13,288,671

1 Trade payables includes US$1,008,147 (2017: US$1,008,147) for licence obligations that are in arbitration as at the date of this report; and are unlikely to be settled until the arbitration is resolved.
2 Other payables includes US$902,937 (2017: US$902,937 for licence obligations that are in arbitration as at the date of this report; and are unlikely to be settled until the arbitration is resolved, cash classified as restricted cash will be utilised to settle this liability, Note 9.
3 In 2017, other payables included US$7,707,097 for potential licence commitments on licences that are no longer held by the Company. Although previously recognised within the financial statements due to contractual terms of the agreements prior to their expiry, management now do not expect a material cash outflow is probable to extinguish these liabilities on a commercial basis. Though as still possible it is disclosed as a contingent liability (Note 20).

13. Issued capital

Ordinary shares participate in dividends and the proceeds on winding up of the Company in proportion to the number of shares held and in proportion to the amount paid up on the shares held.

At shareholders' meetings, each ordinary share is entitled to one vote in proportion to the paid-up amount of the share when a poll is called, otherwise each shareholder has one vote on a show of hands.

Reconciliation of movement in shares on issue

	Number of fully paid ordinary shares	
	2018	2017
Balance at beginning of the year	**155,466,446**	106,685,114
Issue of shares pursuant to a capital raising	-	43,920,000
Issue of shares to staff and Directors	-	4,423,765
Exercise of share options	-	437,567
Balance at end of the year	**155,466,446**	155,466,446

Reconciliation of movements in issued capital

	2018 US$	2017 US$
Balance at beginning of the year	**642,740,272**	611,455,218
Issue of shares pursuant to a capital raising[1,2]	-	33,111,648
Capital raising costs[1,2,3]	-	(2,550,606)
Issue of shares to staff and Directors	-	532,776
Exercise of share options	-	191,238
Share capital at end of the year	**642,740,272**	642,740,272

1 During January 2017, the Company issued 10,670,000 shares at NOK 2.50 each, raising NOK 26,675,000 (US$3,195,988). Costs associated with the capital raising were US$168,612.
2 During May 2017, the Company issued 33,250,000 shares at NOK 7.75 each, raising NOK 257,687,500 (US$29,915,660). Costs associated with the capital raising were US$2,381,994.
3 The 2017 comparative figure has been restated, to reflect additional costs of US$698,000 that were settled by the issue of 776,070 options at NOK 7.75 each, this adjustment was not considered material and only affected equity.

Capital management

Management controls the capital of the Company in order to maximise the return to shareholders and ensure that the Company can fund its operations and continue as a going concern. Capital is defined as issued share capital.

Management effectively manages the Company's capital by assessing the Company's financial risks and adjusting its capital structure in response to changes in these risks and in the market. These responses include the management of expenditure and debt levels, distributions to shareholders and share and option issues. There have been no changes in the strategy adopted by management to control the capital of the Company since the prior reporting period.

Management monitors capital requirements through cash flow forecasting. Management may seek further capital if required through the issue of capital or changes in the capital structure. The Group has no externally imposed capital requirements.

Notes to the consolidated financial statements continued

14. Reserves

Nature and purpose of reserves

Share-based payment reserve

The share-based payments reserve records options and share awards recognised as expenses, issued to employees, Directors and consultants. Refer to Note 16 for further details. The 2017 comparative figure has been restated, to reflect additional capital raising costs of US$698,000 that were settled by the issue of 776,070 options at NOK 7.75 each, this adjustment was not considered material and only affected equity.

Foreign currency translation reserve

The foreign currency translation reserve is used to recognise foreign currency exchange differences arising on translation of functional currency to presentation currency.

Accumulated losses

All other net gains and losses and transactions with owners not recognised elsewhere.

15. Non-controlling interest

	2018 US$	2017 US$
Non-controlling interests at the beginning of the year	**(3,445,687)**	(3,046,199)
Loss attributable to non-controlling interests	**(68,175)**	(399,488)
Non-controlling interests at the end of the year	**(3,513,862)**	(3,445,687)

Summarised financial information in respect of the subsidiary, African Petroleum Senegal Ltd, that has a 10% non-controlling interest is provided below. The summarised financial information below represents amounts before inter-company eliminations.

	2018 US$	2017 US$
Current assets	–	–
Non-current assets	**562,567**	531,576
Current liabilities	**(46,731,684)**	(46,018,943)
Equity attributable to owners of the Company	**(42,655,255)**	(42,041,680)
Non-controlling interests	**(3,513,862)**	(3,445,687)

	2018 US$	2017 US$
Administration expenses	**(197,862)**	(200,721)
Exploration and evaluation expenditure	**(483,890)**	(356,883)
Impairment of exploration and evaluation expenditure	–	(3,437,274)
Loss for the year from continuing operations	**(681,752)**	(3,994,878)
Loss attributable to non-controlling interests	**(68,175)**	(399,488)

16. Share-based payments

	2018 US$	2017 US$
Share-based payment charge for the year[1]	**830,168**	2,532,624

1 The 2017 comparative figure has been restated, to reflect additional charges of US$698,000 from the issue of 776,070 options at NOK 7.75 each, this adjustment was not considered material and only affected equity.

The following reconciles the outstanding share options granted, exercised and forfeited during the year:

	2018			2017		
	Number of options	**Weighted average exercise price A$/NOK**	**Weighted average exercise price equivalent USD[2]**	Number of options[1]	Weighted average exercise price A$/NOK	Weighted average exercise price equivalent USD[2]
Balance at beginning of the period	**14,433,200**			8,059,578		
Granted during the year (NOK)	**6,050,000**	**NOK 1.59**	**US$ 0.18**	7,279,470	NOK 7.27	US$ 0.84
Exercised during the year (NOK)	**-**			(426,667)	NOK 3.64	US$ 0.42
Lapsed during the year (A$)	**(270,562)**	**A$ 4.95**	**US$ 3.49**	(479,181)	A$ 13.65	US$ 9.63
Lapsed during the year (NOK)	**(1,002,000)**	**NOK 2.39**	**US$ 0.28**	-		
Forfeited during the year (NOK)	**(100,000)**	**NOK 1.60**	**US$ 0.18**	-		
Balance at end of the year (A$)	**204,168**	**A$ 2.56**	**US$ 1.81**	474,730	A$ 3.92	US$ 2.77
Balance at end of the year (NOK)	**18,906,470**	**NOK 3.96**	**US$ 0.46**	13,958,470	NOK 4.86	US$ 0.56
Total balance at end of the year	**19,110,638**			14,433,200		
Exercisable at end of the year (A$)	**204,168**	**A$ 2.56**	**US$ 1.81**	474,730	A$ 3.92	US$ 2.77
Exercisable at end of the year (NOK)	**16,106,470**	**NOK 4.37**	**US$ 0.50**	13,958,470	NOK 4.86	US$ 0.56
Exercisable at end of the year	**16,310,638**			14,433,200		

1 The 2017 comparative figure has been restated, to reflect the additional issue of 776,070 options at NOK 7.75 each, this adjustment was not considered material and only affected equity.
2 The US$ equivalent weighted average exercise price as at 31 December 2018.

The share options outstanding at the end of the period had a weighted average remaining contractual life of 1,613 days (2017: 2,020 days).

Options awarded in the current year

During the current year, 6,050,000 unlisted options were issued to staff, Directors and consultants of the Company.5,950,000 unlisted options were subject to vesting conditions dependent on continued employment with the Company for an additional year from the grant date. As at 31 December 2018, 3,150,000 of the unlisted options awarded during the year had vested.

Grant Date	Expiry date	Number of options	Expected life of options (Years)	Risk-free rate (%)	Volatility (%)	Dividend yield (%)	Exercise price Nok	Exercise price equivalent US$	Fair value at grant date Nok	Fair value at grant date US$
22 Jan 2018	02 Jan 2023	50,000	5	2.62	125	-	0.90	0.10	0.90	0.10
21 May 2018	31 May 2023	6,000,000	5	2.89	125	-	1.60	0.18	1.60	0.18

The Company has used the Black-Scholes methodology for measuring the option pricing.

A total of US$830,168 was recognised for options awarded to staff, Directors and consultants of the Company, of this amount US$778,377 has been recognised within the line item "Employee remuneration" within the Statement of Comprehensive Income. US$51,791 has been recognised within the line item "Consulting expenses" within the Statement of Comprehensive Income.

The value of options capitalised during the period was nil (2017: US$698,000).

The options issued to Directors, employees and consultants in the prior year are in recognition of services provided and to be provided in the future. Holders of options do not have any voting or dividend rights in relation to the options.

Options forfeited and lapsed during the current year

During the year, 1,373,562 unlisted options lapsed without being exercised:
1,102,000 with various exercise prices between NOK 1.60 and NOK 4.00
270,562 with various exercise prices of between A$ 3.00 and A$ 37.50

Notes to the consolidated financial statements continued

17. Related party information

Corporate structure

The legal corporate structure of the Group is set out below:

Name	Country of Incorporation	% Equity interest 2018	% Equity interest 2017
Parent entity: African Petroleum Corporation Limited	Australia		
African Petroleum Corporation Ltd	Cayman Islands	**100%**	100%
African Petroleum Corporation Ltd	United Kingdom	**100%**	100%
African Petroleum Corporation (Services) Ltd	United Kingdom	**100%**	100%
African Petroleum Cote d'Ivoire Ltd	Cayman Islands	**100%**	100%
African Petroleum Cote d'Ivoire SAU	Cote d'Ivoire	**100%**	100%
African Petroleum Drilling Services Ltd	Cayman Islands	**100%**	–
African Petroleum Gambia Ltd	Cayman Islands	**100%**	100%
African Petroleum Limited [1]	United Kingdom	**–**	100%
African Petroleum Senegal SAU	Senegal	**100%**	100%
African Petroleum Senegal Ltd	Cayman Islands	**90%**	90%
African Petroleum (SL) Ltd	Sierra Leone	**99.99%**	99.99%
African Petroleum Sierra Leone Ltd	Cayman Islands	**100%**	100%
APCL Gambia B.V.	Netherlands	**100%**	100%
European Hydrocarbons (SL) Ltd	Cayman Islands	**100%**	–
European Hydrocarbon (SL) Ltd	Sierra Leone	**99.99%**	99.99%
European Hydrocarbons Ltd	Cayman Islands	**100%**	100%
European Hydrocarbons Ltd	United Kingdom	**100%**	100%
Regal Liberia Limited	United Kingdom	**100%**	100%

1 During the year subsidiary struck off and dissolved.

(a) Key management personnel

Key management personnel include the Board of Directors as detailed in the Directors' report, the Company Secretary and the following other key personnel:

Mr Michael Barrett	Exploration Director
Mr Christopher Butler	Group Financial Controller

Remuneration of key management personnel

2018	Short-term benefits: Salary and fees US$	Short-term benefits: Salary to purchase shares US$	Short-term benefits: Other cash benefits[2] US$	Post-employment benefits[1] US$	Share-based payments[3]: Shares US$	Share-based payments[3]: Options US$	Total US$
Directors							
D King	12,000	–	–	–	–	84,670	96,670
B Moe	12,000	–	–	–	–	28,037	40,037
J Pace	509,208	–	14,141	–	–	204,535	727,884
T Turner	8,962	–	–	–	–	33,868	42,830
S West	361,087	–	6,015	36,109	–	204,535	607,746
A Wilson	3,400	–	–	–	–	–	3,400
Subtotal	**906,657**	**–**	**20,156**	**36,109**	**–**	**555,645**	**1,518,567**
Key management							
M Barrett	400,092	–	2,241	–	–	136,356	538,689
C Butler	153,796	–	5,646	15,380	–	54,542	229,364
A Hicks	17,722	–	–	–	–	–	17,722
Subtotal	**571,610**	**–**	**7,887**	**15,380**	**–**	**190,898**	**785,775**
Total	**1,478,267**	**–**	**28,043**	**51,489**	**–**	**746,543**	**2,304,342**

1 Post-employment benefits consist of superannuation and pension contributions made by the Group.
2 Other cash benefits relate to health insurance benefits.
3 Share-based payments represent the value of options and performance shares that have been recognised during the current year.

2017	Short-term benefits: Salary and fees US$	Short-term benefits: Salary to purchase shares[2] US$	Short-term benefits: Other cash benefits[3] US$	Post-employment benefits[1] US$	Share-based payments[4]: Shares US$	Share-based payments[4]: Options US$	Total US$
Directors							
D King	9,134	–	–	–	–	131,564	140,698
B Moe	11,081	–	–	–	–	57,144	68,225
J Pace	476,513	342,212	4,819	–	–	410,526	1,234,070
T Turner	9,207	–	–	–	–	52,625	61,832
S West	338,156	260,817	1,281	29,839	–	410,526	1,040,619
A Wilson	12,000	–	–	–	–	55,792	67,792
Subtotal	**856,091**	**603,029**	**6,100**	**29,839**	**–**	**1,118,177**	**2,613,236**
Key management							
M Barrett	374,117	268,870	3,784	–	–	270,083	916,854
C Butler	156,660	53,958	1,609	13,875	–	80,329	306,431
A Hicks	19,959	–	–	–	–	39,469	59,428
I Philliskirk[5]	–	61,034	–	–	–	21,831	82,865
Subtotal	**550,736**	**383,862**	**5,393**	**13,875**	**–**	**411,712**	**1,365,578**
Total	**1,406,827**	**986,891**	**11,493**	**43,714**	**–**	**1,529,889**	**3,978,814**

1 Post-employment benefits consist of superannuation and pension contributions made by the Group.
2 Contractual salary that had been withheld from UK staff during the period from December 2015 to April 2017 was finally paid in December 2017. The net amount due to staff was used to purchase shares in the Company at the closing rate of the prior day. The associated payroll taxes were settled in cash post year end.
3 Other cash benefits relate to health insurance benefits.
4 Share-based payments represent the value of options and performance shares that have been recognised during the current year.
5 Mr Philliskirk resigned on 7 September 2016.

Option holdings by directors and other key management personnel

	Balance 1 January 2018	Options acquired	Awarded as remuneration	Options exercised	Net change other	Balance 31 December 2018	Exercisable	Not exercisable
Directors								
D King	500,000	–	500,000	–	–	1,000,000	1,000,000	–
B Moe	450,000	–	200,000	–	–	650,000	550,000	100,000
J Pace	3,125,000	–	1,500,000	–	(75,000)	4,550,000	3,800,000	750,000
T Turner	200,000	–	200,000	–	–	400,000	400,000	–
S West	3,128,338	–	1,500,000	–	(58,338)	4,570,000	3,820,000	750,000
A Wilson	450,000	–	–	–	(450,000)	–	–	–
Key management personnel								
M Barrett	1,998,331	–	1,000,000	–	(58,331)	2,940,000	2,440,000	500,000
C Butler	440,000	–	400,000	–	(20,000)	820,000	620,000	200,000
A Hicks	150,000	–	–	–	–	150,000	150,000	–
	10,441,669	**–**	**5,300,000**	**–**	**(661,669)**	**15,080,000**	**12,780,000**	**2,300,000**

Share holdings by Directors and other key management personnel

	Balance 1 January 2018	Shares purchased	Granted as remuneration	On exercise of options	Net change other	Balance 31 December 2018
Directors						
D King	30,000	–	–	–	–	**30,000**
B Moe	10,000	–	–	–	–	**10,000**
J Pace	1,498,938	–	–	–	–	**1,498,938**
T Turner	4,167	–	–	–	–	**4,167**
S West	1,377,554	–	–	–	–	**1,377,554**
A Wilson	10,000	–	–	–	(10,000)	**–**
Key management personnel						
M Barrett	1,151,667	–	–	–	–	**1,151,667**
C Butler	234,296	–	–	–	–	**234,296**
A Hicks	–	–	–	–	–	**–**
	4,316,622	**–**	**–**	**–**	**–**	**4,306,622**

Notes to the consolidated financial statements continued

17. Related party information continued

(b) Transactions and period end balances with related parties:

	2018 US$	2017 US$
Loan receivable from key management personnel	**1,501,354**	1,590,587
Impairment allowance	**(1,501,354)**	(1,590,587)
Total receivables from related parties (Note 8)	**–**	–

Unless otherwise stated, all of the outstanding balances are unsecured, interest-free with no specific repayment terms.

(i) During 2012 and 2013, US$1,037,994 (£645,359) was loaned to former CEO Karl Thompson and US$630,497 (£390,321) was loaned to Jens Pace to cover tax payable on performance shares awarded to Mr Thompson and Mr Pace. The loans can only be used for the payment of the relevant tax (upon presentation of the tax amount) and must be repaid from the sale of any shares. The shares are subject to a voluntary escrow, whereby the shares cannot be sold or transferred until the loans are discharged and the proceeds are to be applied to discharge the loans. During the period, no interest was recognised on the basis that it was not probable that the amounts would be received, therefore could not be recognised under revenue policy, so no further impairment was necessary. In previous years, interest was charged on the loans at 4%. The loan agreements were approved by the Board of Directors as being on arm's length terms. If prior to the repayment date the proceeds from the sale of the performance shares are insufficient in total to cover the loans, the Company will waive the remaining balance of the loans. At 31 December 2018, the performance shares awarded to Mr Thompson have a market value of US$7,987 and the total limited recourse feature of the loan of US$935,878 (2017: US$991,502) has been recognised as a share-based payment liability. At 31 December 2018, the performance shares awarded to Mr Pace have a market value of US$2,227 and the total limited recourse feature of the loan of US$565,476 (2017: US$599,085) has been recognised as a share-based payment liability. During the year, the movement in the limited recourse feature of the loans is due to foreign exchange differences.

(ii) As at 31 December, the following amounts were payable to Directors of the Company or their nominees:

	2018 US$	2017 US$
Dr King	**3,000**	6,000
Mr Moe	**18,000**	6,000
Mr Pace	**10,476**	12,522
Mr Turner	**776**	859
Mr West	**–**	–
Mr Wilson	**–**	1,000

18. Financial assets and financial liabilities

	2018 US$	2017 US$
Financial assets		
Cash and cash equivalents	**6,286,407**	13,186,482
Trade and other receivables	**119,915**	113,844
Restricted cash	**–**	902,937
	6,406,322	14,203,263
Financial liabilities		
Trade and other payables	**3,839,524**	13,288,671

Financial risk management policies

The Company's principal financial instruments comprise receivables, payables and cash and derivatives for financial liabilities.

Risk exposure and responses

The Company manages its exposure to key financial risks, including currency risk in accordance with the Company's financial risk management policy. The objective of the policy is to support the delivery of the Company's financial targets while protecting future financial security. The Company does not use any form of derivatives to hedge its financial risks. Exposure limits are reviewed by management on a continuous basis. The Company does not enter into or trade financial instruments, including derivative financial instruments, for speculative purposes. The Board of Directors has overall responsibility for the establishment and oversight of the risk management framework. Management monitors and manages the financial risks relating to the operations of the Company through regular reviews of the risks.

Treasury risk management

The Board analyses financial risk exposure and evaluates treasury strategies in the context of the most recent economic conditions and forecasts.

The overall risk management strategy seeks to assist the Company in meeting its financial targets, whilst minimising potential adverse effects on financial performance.

Financial risk exposure and management
The main risks the Company is exposed to through its financial instruments are foreign currency risk, equity risk, liquidity risk and credit risk.

Foreign currency risk
The Group does not have a material exposure to changes in foreign exchange rates.

Equity price risk
The Group does not have a material exposure to market price risk arising from uncertainties about the future value of the Group's share price.

Liquidity risk
Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to its reputation.

The Company manages liquidity risk by maintaining adequate cash reserves from funds raised in the market and by continuously monitoring forecast and actual cash flows. The Company does not have any external borrowings.

The following are the contractual maturities of financial liabilities:

Trade and other payables	0 - 3 months US$	3 - 6 months US$	6 - 12 months US$	1 - 5 years US$	> 5 years US$	Total US$
2018	**3,839,524**	–	–	–	–	**3,839,524**
2017	13,288,671	–	–	–	–	13,288,671

To satisfy the commitments and contingencies as detailed in Note 2 and Note 20, the Group will need significant funding to meet its explorations and drilling obligations. The Directors are continually monitoring the areas of interest and are exploring alternatives for funding the development of the Group's various licences when economically recoverable reserves are confirmed. Further details of the Group's liquidity strategies to meet its liquidity requirements are included in Note 2 Going Concern.

Credit risk
Credit risk arises from the financial assets of the Group, which comprise cash and cash equivalents, trade and other receivables and available-for-sale financial assets. The Group's exposure to credit risk arises from the potential default of the counterparty, with a maximum exposure equal to the carrying amount of the financial assets (as outlined in each applicable note).

The Company has adopted the policy of only dealing with creditworthy counter-parties and obtaining sufficient collateral or other security where appropriate, as a means of mitigating the risk of financial loss from defaults. The Company does not have any significant credit risk exposure to any single counter-party.

(i) Cash and cash equivalents
The Company limits its exposure to credit risk by only investing in liquid securities and only with counterparties that have an acceptable credit rating. As at 31 December 2018, US$6,252,502 is held by a UK bank with a S&P short term credit rating of A-2.

(ii) Trade and other receivables
Trade and other receivables as at the reporting date mainly comprise GST and short-term loans to be refunded to the Company. The Directors consider that the carrying amount of trade and other receivables approximates their fair value. All trade and other receivables as disclosed in Note 8 are not rated by any rating agencies.

The credit quality of financial assets that are neither past due nor impaired can be assessed by reference to external credit ratings (if available) or to historical information about counterparty default rates.

19. Segment information
For management purposes, the Group is organised into one main operating segment, which involves exploration for hydrocarbons. All of the Group's activities are interrelated, and discrete financial information is reported to the chief operating decision maker as a single segment. Accordingly, all significant operating decisions are based upon analysis of the Group as one segment. The financial results from this segment are equivalent to the financial statements of the Group as a whole.

The Group only has one operating segment being exploration for hydrocarbons.

The analysis of the location of non-current assets is as follows:

	2018 US$	2017 US$
Gambia	–	–
Senegal	**2,385**	–
Sierra Leone	–	9,107,859
United Kingdom	**4,715**	1,010,651
	7,100	10,118,510

Notes to the consolidated financial statements continued

20. Commitments and contingencies

Commitments

Exploration commitments

The Company has entered into obligations in respect of its exploration projects. Outlined below are the minimum expenditures required as at 31 December are as follows:

	2018 US$	2017 US$
Within one year[1]	40,000,000	41,583,021

1 The commitment in Senegal includes US$40m for an exploration well in each licence, however this assumes that the Company is successful in retaining the legal title for these licences and that the Company then drills these wells with 90% equity.

Office rental commitments

The Company has entered into obligations in respect of office premises. Commitments for the payment of office rental in existence at the reporting date but not recognised as liabilities are as follows:

	2018 US$	2017 US$
Within 1 year	44,655	15,820

Contingencies

Withholding tax

There is a remote risk that the Company may have been required to withhold payment on certain services provided by subcontractors in respect of exploration operation undertaken in previous years. The withheld amounts may have been due to the tax authorities and credited against the subcontractors own income tax liability. Considering the passage of time and the former operations being carried out by a now dormant subsidiary company, the Company has reassessed the possible exposure to the Company as remote and no longer a contingent liability as disclosed in previous years.

Relinquished licence commitments

There is uncertainty on whether some elements of the obligations under the licences that are no longer held by the Company have been extinguished when the licences were relinquished in prior years. The Company is however of the view that they no longer believe there is any present obligation with respect to these liabilities and have therefore reversed these in the financial statements. Management expect to resolve this uncertainty, either by obtaining a legal assessment that all obligations have been settled or through restructuring the Group. The maximum exposure for these liabilities is equivalent to the other payable that had been recognised in previous years (Note 12).

21. Loss per share

	31 December 2018 US$	31 December 2017 US$
Loss attributable to ordinary shareholders		
Loss from continuing operations attributable to the ordinary equity holders used in calculating basic loss per share	(8,343,987)	(34,620,064)
Loss attributable to the ordinary equity holders used in calculating basic loss per share	(8,343,987)	(34,620,064)
	Number of shares	
Weighted average number of ordinary shares outstanding during the period used in the calculation of basic and diluted loss per share	155,466,536	139,248,783

Options on issue are considered to be potential ordinary shares and have been included in the determination of diluted loss per share only to the extent to which they are dilutive. There are 19,110,638 options as at 31 December 2018 (2017: 14,433,200 options). These options have not been included in the determination of basic loss per share because they are considered to be anti-dilutive.

22. Parent entity financial information

a) Summary financial information

The individual financial statements of the parent entity show the following aggregate amounts:

	31 December 2018 US$	31 December 2017 US$
Statement of financial position		
Current assets	**41,639**	51,306
Non-current assets	**14,622,233**	15,140,000
Total assets	**14,663,872**	15,191,306
Current liabilities	**(246,470)**	(157,296)
Total liabilities	**(246,470)**	(157,296)
Net assets	**14,417,402**	15,034,009
Shareholders' equity		
Issued capital	**1,039,121,375**	1,039,121,375
Reserves	**(6,191,772)**	(7,142,078)
Accumulated losses	**(1,018,512,201)**	(1,016,945,288)
	14,417,402	15,034,009
Net loss for the year	**(1,566,913)**	(42,118,971)
Total comprehensive loss	**(1,566,913)**	(42,118,971)

b) Guarantees entered into by the parent entity

As at 31 December 2018, the parent entity has not provided any financial guarantees in respect of bank overdrafts and loans of subsidiaries (31 December 2017: nil).

23. Standards issued but not yet effective

Australian Accounting Standards and Interpretations that have recently been issued or amended but are not yet effective and have not been adopted by the Company for the reporting period ended 31 December 2018 are set out below. The application of these Standards and Interpretations, once effective, will not have any impact on the Company other than disclosure.

Standard/Amendment	Effective for annual reporting periods beginning on or after
AASB 16 Leases	1 January 2019
AASB 17 Insurance Contracts	1 January 2021
AASB 2014-10 Amendments to Australian Accounting Standards – Sale or Contribution of Assets between an Investor and its Associate or Joint Venture, AASB 2015-10 Amendments to Australian Accounting Standards – Effective Date of Amendments to [AASB 10 and AASB 128] and AASB 2017-5 Amendments to Australian Accounting Standards – Effective Date of Amendments to AASB 10 and AASB 128 and Editorial Corrections	1 January 2022 (Editorial corrections in AASB 2017-5 apply from 1 January 2018)
AASB 2017-6 Amendments to Australian Accounting Standards – Prepayment Features with Negative Compensation	1 January 2019
AASB 2017-7 Amendments to Australian Accounting Standards – Long-term Interests in Associates and Joint Ventures	1 January 2019
AASB 2018-1 Amendments to Australian Accounting Standards – Annual Improvements 2015-2017 Cycle	1 January 2019
AASB 2018-2 Amendments to Australian Accounting Standards – Plan Amendment, Curtailment or Settlement	1 January 2019
AASB 2018-3 Amendments to Australian Accounting Standards – Reduced Disclosure Requirements	1 January 2019
AASB 2018-6 Amendments to Australian Accounting Standards – Definition of a Business	1 January 2020
AASB 2018-7 Amendments to Australian Accounting Standards – Definition of Material	1 January 2020
Interpretation 23 Uncertainty over Income Tax Treatments	1 January 2019

24. Events subsequent to reporting date

On 19 March 2019, the Company announced the proposed combination with PetroNor E&P Ltd ("PetroNor") for an all-share consideration of c. 816 million shares in African Petroleum (the "Transaction"). PetroNor is a privately owned, Africa-focused E&P independent, that holds a 10.5% indirect interest in the PNGF Sud fields ("PNGF Sud") and right to negotiate entry into a 14.7% indirect interest in an exploration license covering the PNGF Bis fields ("PNGF Bis") (collectively the "Congo Assets"). The Transaction is subject to shareholder approval, and certain other customary conditions. African Petroleum will at completion of the Transaction change its name to PetroNor E&P Limited (the "Combined Company").

On 29 March 2019, Notice was given that the General Meeting of Shareholders to approve the Transaction will be held on 24 April 2019.
On 24 April 2019, the Company announced that all resolutions put forward at the General Meeting of the Company were passed on a show of hands.

Directors' declaration

In accordance with a resolution of the Directors of African Petroleum Corporation Limited, I state that:
In the opinion of the Directors:

(a) the financial statements and notes of African Petroleum Corporation Limited for the year ended 31 December 2018 are in accordance with the Corporations Act 2001, including:
  (i) giving a true and fair view of its financial position as at 31 December 2018 and of its performance for the year ended on that date; and
  (ii) complying with Australian Accounting Standards (including the Australian Accounting Interpretations) and the Corporations Regulations 2001; and
  (iii) complying with International Financial Reporting Standards as disclosed in Note 2.

(b) subject to the achievement of matters disclosed in Note 2 (Going Concern), there are reasonable grounds to believe that the Company will be able to pay its debts as and when they become due and payable.

The Directors have been given the declarations required by Section 295A of the Corporations Act 2001 from the Chief Executive Officer and Chief Financial Officer for the year ended 31 December 2018.

Signed in accordance with a resolution of the Directors:

Jens Pace

Jens Pace
Chief Executive Officer
Perth, 25 April 2019

Independent auditor's report

To the members of African Petroleum Corporation Limited

Report of the Audit of the Financial Report

Opinion

We have audited the financial report of African Petroleum Corporation Limited (the "Company") and its subsidiaries (the "Group"), which comprises the consolidated statement of financial position as at 31 December 2018, the consolidated statement of profit or loss and other comprehensive income, the consolidated statement of changes in equity and the consolidated statement of cash flows for the year then ended, and notes to the financial report, including a summary of significant accounting policies and the Directors' declaration.

In our opinion the accompanying financial report of the Group, is in accordance with the Corporations Act 2001, including:
(i) giving a true and fair view of the Group's financial position as at 31 December 2018 and of its financial performance for the year ended on that date; and
(ii) complying with Australian Accounting Standards and the Corporations Regulations 2001.

Basis for opinion

We conducted our audit in accordance with Australian Auditing Standards. Our responsibilities under those standards are further described in the Auditor's responsibilities for the audit of the Financial Report section of our report. We are independent of the Group in accordance with the Corporations Act 2001 and the ethical requirements of the Accounting Professional and Ethical Standards Board's APES 110 Code of Ethics for Professional Accountants (the Code) that are relevant to our audit of the financial report in Australia. We have also fulfilled our other ethical responsibilities in accordance with the Code.

We confirm that the independence declaration required by the Corporations Act 2001, which has been given to the Directors of the Company, would be in the same terms if given to the Directors as at the time of this auditor's report.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material uncertainty related to going concern

We draw attention to Note 2 in the financial report which describes the events and/or conditions which give rise to the existence of a material uncertainty that may cast significant doubt about the Group's ability to continue as a going concern and therefore the Group may be unable to realise its assets and discharge its liabilities in the normal course of business. Our opinion is not modified in respect of this matter.

Key audit matters

Key audit matters are those matters that, in our professional judgement, were of most significance in our audit of the financial report of the current period. These matters were addressed in the context of our audit of the financial report as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. In addition to the matter described in the Material uncertainty related to going concern section, we have determined the matters described below to be the key audit matters to be communicated in our report.

Exploration license liabilities

Key audit matter	How the matter was addressed in our audit
As described in Note 12 and 20 of the financial report, the Group has relinquished a number of its exploration licenses. The Group had previously recognised accrued liabilities for potential estimated costs under the license agreements. Given the relinquishment of these licenses, management has reassessed the Groups obligations under these arrangement and accordingly have derecognised these labilities within the financial statements. Following the Group's reassessment above, a contingent liability has been disclosed in Note 20 of the financial statements. Given the judgement involved, this is considered a key audit matter.	Our procedures included, but were not limited to the following: • reading all correspondence in relation to the relinquishment of the license agreements and assessing management's assessment on the obligation and settlement of the accrued liabilities; • reading board minutes to assess whether there is any evidence to suggest that the accrued costs are due and payable; • reviewing legal costs and correspondence to assess whether there is evidence of any disputes arising on the relinquishment from the licenses; and • assessing the adequacy of the related disclosures in the financial statements.

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Independent auditor's report continued

Other information

The Directors are responsible for the other information. The other information comprises the information contained in the Group's annual report for the year ended 31 December 2018, but does not include the financial report and our auditor's report thereon.

Our opinion on the financial report does not cover the other information and we do not express any form of assurance conclusion thereon.

In connection with our audit of the financial report, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial report or our knowledge obtained in the audit or otherwise appears to be materially misstated.

If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

Responsibilities of the Directors for the financial report

The Directors of the Company are responsible for the preparation of the financial report that gives a true and fair view in accordance with Australian Accounting Standards and the Corporations Act 2001 and for such internal control as the Directors determine is necessary to enable the preparation of the financial report that gives a true and fair view and is free from material misstatement, whether due to fraud or error.

In preparing the financial report, the Directors are responsible for assessing the ability of the Group to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless the Directors either intend to liquidate the Group or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial report

Our objectives are to obtain reasonable assurance about whether the financial report as a whole is free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with the Australian Auditing Standards will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of this financial report.

A further description of our responsibilities for the audit of the financial report is located at the Auditing and Assurance Standards Board website (http://www.auasb.gov.au/Home.aspx) at:

http://www.auasb.gov.au/auditors_responsibilities/ar1.pdf

This description forms part of our auditor's report.

BDO Audit (WA) Pty Ltd

Phillip Murdoch
Director
Perth, 25 April 2019

Unaudited additional shareholder information

Additional information – Oslo Axess

In compliance with Oslo listing requirements and Section 3-3a of the Norwegian Accounting Act, the following information is provided in addition to the information set-out elsewhere in this Annual Report.

Nature of the business

The principal activity of the Company is oil and gas exploration and is outlined in the Directors Report on page 8.

Working environment

As an operator of offshore concessions, it is the duty of African Petroleum to provide a safe working environment and minimise any adverse impact on the environment. Health, safety, environment and security policies are embedded throughout all of the Company's core operations. In this regard, we strive for continuous improvement as lessons learned from past operations are incorporated into business practices going forward.

During the year ended 31 December 2018 there were no staff injuries or accidents reported, and no illnesses suffered by staff that required extended absences from the workplace.

Workplace equality

African Petroleum is committed to workplace diversity which includes but is not limited to gender, age, ethnicity and cultural background. Where possible the Company fills employment positions with local skilled people. During 2018 all staff positions in our West African offices were held by local people.

Proportion of local West African employees:

	Actual	Objective
Organisation as a whole	50%	50%
Board	Nil	10%

African Petroleum's Diversity Policy defines initiatives which assist the Company in maintaining and improving the diversity of its workforce. In accordance with this policy and Corporate Governance Principles, the Board has established the following objectives in relation to gender diversity which it hopes to achieve over the next five years as positions become vacant and appropriately skilled candidates are available:

Proportion of women

	Actual	Objective
Organisation as a whole	20%	20%
Executive management team	Nil	20%
Board	Nil	20%

As at 27 March 2019, the Company had 3,407 shareholders. The table below shows the 20 largest shareholders in the Company, including those registered in the VPS, as at 27 March 2019.

	Shareholder	Number of Shares	%
1	Nordnet Bank AB	14,684,291	9.45
2	Avanza Bank AB	8,059,252	5.18
3	Nordnet Livsforsikring AS	6,937,727	4.46
4	Telinet Energi AS	5,602,461	3.60
5	Danske Bank A/S	3,470,945	2.23
6	Gekko AS	2,791,789	1.80
7	Nordea Bank Abp	2,311,235	1.49
8	Citibank, N.A.	2,282,310	1.47
9	UBS Switzerland AG	2,273,305	1.46
10	Ole Andreas Baksaas	2,191,709	1.41
11	Swedbank AB	2,114,424	1.36
12	Six Sis AG	1,714,575	1.10
13	Minh Hoang Pham	1,590,000	1.02
14	Jens Pace	1,498,938	0.96
15	Netfonds Livsforsikring AS	1,448,024	0.93
16	Cresthaven Investments Pty Ltd	1,377,544	0.89
17	Steinar Grønland	1,353,000	0.87
18	Michael Barrett	1,151,667	0.74
19	John Andreas Rognstad	1,150,000	0.74
20	Clearstream Banking S.A.	1,095,904	0.70
		65,099,100	
	Others	90,367,346	58.13
	Total	**155,466,446**	**100.00**

FINANCIAL STATEMENTS

Unaudited additional shareholder information continued

Impact on the external environment
The Company is aware of its environmental obligations with regards to its exploration activities and ensures that it complies with the relevant environmental regulations when carrying out any exploration work. There have been no significant known breaches of the Company's exploration license conditions or any environmental regulations to which it is subject.

Going concern assumption
The financial statements have been prepared on a going concern basis which contemplates the continuity of normal business activities and the realisation of assets and the settlement of liabilities in the ordinary course of business. Further details are provided in Note 2 to the audited financial statements.

Risk assessment
As an exploration company in the oil and gas industry, the Company operates in an inherently risky sector. Oil and gas prices are subject to volatile price changes from a variety of factors, including international economic and political trends, expectation of inflation, global and regional demand, currency exchange fluctuations, interest rates and global or regional consumption patterns. These factors are beyond the control of the Company and may affect the marketability of oil and gas discovered. In addition, the Company is subject to a number of risk factors inherent in the oil and gas upstream industry, including operational and technical risks, reserve and resource estimates, risks of operating in a foreign country (including economic, political, social and environmental risks) and available resources. We recognise these risks and manage our operations in order to minimise our exposure to the extent practical.

Further details on the Company's financial risk management policies are set out in Note 18 to the audited financial statements.

Outlook
The expected results of the Company will vary significantly dependent on the completion of the Transaction with PetroNor (refer to Note 24 to the audited financial statements). Assuming the Transaction is completed, the portfolio will be considerably diversified, whilst simultaneously strengthening the Combined Company's position with regards to ongoing arbitration and farm-down processes. The Combined Company will benefit from a proven reserve base generating strong and predictable cash flow and material upside potential from the Congo assets, as well as considerable exploration upside from our existing portfolio.

Further details on the Company's outlook are described in the Directors Report of the annual report.

Rights and obligations of shareholders
In accordance with section 5-8a of the Securities Trading Act, the Company provides the following information:

a. the Company's share capital consists entirely of ordinary shares. Further details are set-out in Note 13 to the audited financial statements. Over 98.08% of the Company's ordinary shares are admitted for trading on the Oslo Axess (Norway);
b. there are no restrictions on the transfer of securities;
c. significant direct and indirect shareholdings are set-out on page 43 of the annual report;
d. no holders of any securities have special control rights;
e. the Company does not operate an employee share scheme;
f. there are no restrictions on voting rights;
g. there are no agreements between shareholders which are known to the Company and which may result in restrictions on the transfer of securities and/or voting rights within the meaning of Directive 2001/34/EC;
h. the Company's Constitution provides that the Board of Directors shall have no fewer than three Directors and no more than 12 Directors. The Directors are elected by a general meeting of shareholders by ordinary resolution. Additionally, pursuant to Clause 13.4 of the Constitution, the Board of Directors may at any time appoint a person to be a Director, provided that the maximum number of Directors is not exceeded. Any such Director appointed will hold office until the next general meeting and will be eligible for re-election. At the Company's annual general meeting, one-third of the Directors for the time being, shall retire from office, provided always that no Director except a Managing Director shall hold office for a period in excess of three years without submitting himself for re-election. The Directors to retire at an annual general meeting are those who have been longest in office since their last election. A retiring Director is eligible for re-election. In the event of equal voting at a Director's meeting, the Chairman of the meeting shall have a second or casting vote providing there is more than two Directors competent to vote on the question. As the Company is incorporated in Australia, the Australian Corporations Act requires the Company to have at least two Directors that reside in Australia.
i. the Company may modify or repeal its constitution or a provision of its constitution by special resolution of shareholders;
j. pursuant to section 198A of the Australian Corporations Act, the business of a company is managed by or under the direction of the Board of Directors. Pursuant to Clause 2.2 of the Company's Constitution, the Board of Directors has the power to issue shares;
k. subject to the requirements in the Australian Corporations Act, the Company may purchase its own shares in accordance with the buy-back provisions of the Australian Corporations Act, on such terms and at such times as may be determined by the Directors from time to time and approved by the shareholders as required pursuant to the Australian Corporations Act. The Company is not entitled to hold its own shares, subject to exceptions set out in Section 259A of the Australian Corporations Act. Any shares repurchased by the Company will need to be cancelled;
l. there are no significant agreements to which the Company is a party and which take effect, alter or terminate upon a change of control of the Company following a takeover bid;
m. there are no agreements between the Company and its Board members or employees providing for compensation if they resign or are made redundant without valid reason or if their employment ceases because of a takeover bid.

Corporate governance
The Board of Directors of African Petroleum is committed to administering its corporate governance policies and procedures with openness and integrity, pursuing the true spirit of corporate governance commensurate with African Petroleum's needs. Given its Australian domicile and former NSX listing, the Company's corporate governance framework has been constructed in recognition of, and with regard to, the Australian Corporations Act; the ASX Corporate Governance Council's ("CGC") Principles of Good Corporate Governance and Best Practice Recommendations ("Recommendations") and CGC published guidelines; and an extensive range of varying legal, regulatory and governance requirements applicable to publicly listed companies in Australia. The Board of Directors supports the principles of effective corporate governance and is committed to adopting high standards of performance and accountability, commensurate with the size of the Company and its available resources. Accordingly, the Board of Directors has adopted corporate governance principles and practices designed to promote responsible management and conduct of the Company's business. The current corporate governance plan adopted by the Company is available on the Company's website at www.africanpetroleum.com.au. The Company is in compliance with the NSX Corporate Governance Principles.

The Companies policies and practice for corporate governance are further outlined in the Company's Corporate Governance Statement on page 15 of the annual report.

Reporting – payments to governments statement
This country-by-country report has been developed to comply with the legal requirements in the Norwegian Security Trading Act ("Verdipapirhandelloven") § 5-5a, valid from 2014. The detailed regulation can be found in the regulation "Forskrift om land-for-land rapportering". In 2018, the Company was engaged in extracting activities encompassed by the legislation above in the following countries: The Gambia, Senegal and Sierra Leone. This report discloses relevant payments to governments for extractive activities in the countries above, in addition to some contextual information as required by the regulation in the "Forskrift om land-for-land rapportering".

Basis for preparation
The report includes direct payments to governments from subsidiaries, joint operations and joint ventures. In some cases, however, certain payments to governments may be made by an operator on behalf of a partnership. This is often the case for area fees. In such cases, the Company will report their paying interest share of the payment made by the operator.

Definitions
Government – In the context of this report, a government means any national, regional or local authority of a country. It includes a department, agency or undertaking controlled by that authority.

Project – For this reporting a project is defined as an investment in a concession agreement.

Licence fees – Typically levied on the right to use a geographical area for exploration, development and production and include rental fees, area fees, entry fees, severance tax and concession fees and other considerations for licences and/or concessions. Administrative government fees that are not specifically related to the extractive sector, or to access extractive resources, are excluded.

Materiality – As per the "Forskrift om land-for-land rapportering" payments made as a single payment, or as a series of connected payments that equal or exceed Norwegian kroner (NOK) 800.000 during the year are disclosed.

Reporting currency – Payments to governments are converted from the functional currency of each legal entity into the presentation currency, United States Dollars (USD). The payments for entities whose functional currencies are other than USD are converted into USD at the foreign exchange rate at the average annual rate.

Payments to governments and contextual information
The consolidated overview below discloses the sum of the Company's payments to governments in each individual country where extractive activities are performed, per payment type and country/project. As the Group's projects are all at the exploratory stage, there are no taxes, royalties, dividends to currently report.

Payments per project

Project	Licence fees /USD
A1	Nil
A4	Nil
Total The Gambia	Nil
ROP	Nil
SOSP	Nil
Total Senegal	Nil
SL03	125,000
SL4A	294,075
Total Sierra Leone	419,075

Payments per government

Government	Licence fees /USD
Government 1(Federal)	Nil
Government 2 (Municipality)	Nil
Government 3 (State owned company)	Nil
Total The Gambia	Nil
Government 1(Federal)	Nil
Government 2 (Municipality)	Nil
Government 3 (State owned company)	Nil
Total Senegal	Nil
Government 1(Federal)	419,075
Government 2 (Municipality)	Nil
Government 3 (State owned company)	Nil
Total Sierra Leone	419,075

FINANCIAL STATEMENTS

Unaudited additional shareholder information continued

Legal entities by country

As per the "Forskrift om land-for-land rapportering" it's required that the Company report on certain contextual information at corporate level. This includes information on localisation of subsidiary, employees per subsidiary and interests paid to other legal entities within the Group.

Legal corporate structure of the Group during 2018 is set out below:

Name	Country of incorporation	Ownership	Main country of operations	Employees[1]	Interest paid to a Group entity
African Petroleum Corporation Ltd	Australia	n/a	United Kingdom	–	–
African Petroleum Corporation (Services) Ltd	United Kingdom	100%	United Kingdom	5	–
African Petroleum Drilling Services Ltd	Cayman Islands	100%	United Kingdom	–	–
African Petroleum Corporation Ltd	United Kingdom	100%	United Kingdom	–	–
African Petroleum Corporation Ltd	Cayman Islands	100%	United Kingdom	–	–
European Hydrocarbons Ltd	Cayman Islands	100%	United Kingdom	–	–
European Hydrocarbons (SL) Ltd	Cayman Islands	100%	United Kingdom	–	–
African Petroleum Liberia Ltd	Cayman Islands	100%	United Kingdom	–	–
Regal Liberia Limited	United Kingdom	100%	United Kingdom	–	–
Total employees in United Kingdom				**5**	**–**
African Petroleum Côte d'Ivoire Ltd	Cayman Islands	100%	Cote d'Ivoire	–	–
African Petroleum Côte d'Ivoire SAU	Cote d'Ivoire	100%	Cote d'Ivoire	–	–
Total employees in Cote d'Ivoire				**–**	**–**
African Petroleum Gambia Ltd	Cayman Islands	100%	The Gambia	2	–
APCL Gambia B.V.	Netherlands	100%	The Gambia	–	–
Total employees in The Gambia				**2**	**–**
African Petroleum Senegal Ltd	Cayman Islands	90%	Senegal	–	–
African Petroleum (Senegal) SAU	Senegal	100%	Senegal	2	–
Total employees in Senegal				**2**	**–**
African Petroleum Sierra Leone Ltd	Cayman Islands	100%	Sierra Leone	–	–
African Petroleum (SL) Ltd	Sierra Leone	99.99%	Sierra Leone	1	–
European Hydrocarbon (SL) Ltd	Sierra Leone	99.99%	Sierra Leone	–	–
European Hydrocarbons Ltd	United Kingdom	100%	Sierra Leone	–	–
Total employees in Sierra Leone				**1**	**–**

1 Employees number is the average during the year.

Responsibility statement

We confirm that:

a. to the best of our knowledge, the financial statements have been prepared in accordance with applicable accounting standards and give a true and fair view of the assets, liabilities, financial position and profit or loss of the issuer and the Group taken as a whole; and
b. that the Directors Report together with the Additional Information – Olso Axess includes a fair review of the development and performance of the business and the position of African Petroleum Corporation Limited and the Group taken as a whole, together with a description of the principal risks and uncertainties that they face; and
c. to the best of our knowledge, the country-by-country report for 2018 has been prepared in accordance with the Norwegian Security Trading Act Section 5-5a."

David King
Chairman of the Board

Bjarne Moe
Director of the Board

Jens Pace
CEO and Executive Director of the Board

Timothy Turner
Director of the Board

Stephen West
CFO and Executive Director of the Board

Corporate directory

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David King, Chairman
Jens Pace, Chief Executive Officer
Stephen West, Chief Financial Officer
Anders Bjarne Moe
Timothy Turner

COMPANY SECRETARY
Angeline Hicks

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APPENDIX F:

INDEPENDENT PRACTIONER'S

ASSURANCE REPORT

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P. O. Box. 1704 Vika
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N-0121 Oslo
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To the Board of Directors of PetroNor E&P ASA

Independent Assurance Report on the Pro Forma Financial Information

We have completed our assurance engagement to report on the compilation of unaudited pro forma financial information of PetroNor E&P ASA (the "Company"). The pro forma financial information consists of the unaudited pro forma statement of comprehensive income for the twelve month period ended 31 December 2020, the unaudited pro forma statement of comprehensive income for the six month period ended 30 June 2021, and related notes as set out in Section 11.3 in the Unaudited Pro Forma Financial Information dated 12 November 2021 issued by the Company, which will be attached to the Company's prospectus (the "Prospectus"). The applicable criteria on the basis of which the Board of Directors and Management of the Company has compiled the pro forma financial information are specified in Commission Delegated Regulation (EU) 2019/980 as incorporated in the Norwegian Securities Trading Act and the Securities Regulations § 7-1 and described in section 11.3 in the Unaudited Pro Forma Financial Information (the "applicable criteria").

The pro forma financial information has been compiled by the Board of Directors and Management of the Company to illustrate the impact of the transaction set out in section 11.3 in the Unaudited Pro Forma Financial Information on the Company's consolidated financial performance for the twelve month period ended 31 December 2020 and the six month period ended 30 June 2021 as if the transaction had taken place at 1 January 2020 and 1 January 2021 respectively. As part of this process, information about PetroNor E&P Limited's (the Company's parent company whose shares will be swapped for shares in the Company in connection with the Redomiciliation as described in the prospectus) and the acquired entity's financial performance for the twelve month period ended 31 December 2020 has been extracted by the Board of Directors and Management of the Company from PetroNor E&P Limited's and the acquired entity's audited financial statements for 2020. Information about PetroNor E&P Limited's financial performance for the six month period ended 30 June 2021 has been extracted by the Board of Directors and Management of the Company from PetroNor Limited's unaudited interim financial statements for the six month period ended 30 June 2021. Information about the acquired entity's financial performance for the four month period ended 30 April 2021 has been extracted by the Board of Directors and Management of the Company from the acquired company's management accounts.

The Board of Directors' and Management's Responsibility for the Pro Forma Financial Information

The Board of Directors and Management of the Company are responsible for compiling the pro forma financial information on the basis of the applicable criteria.

Our Independence and Quality Control

We have complied with the independence and other ethical requirements of the Code of Ethics for Professional Accountants issued by the International Ethics Standards Board for Accountants, which is founded on fundamental principles of integrity, objectivity, professional competence and due care, confidentiality and professional behavior.

The firm applies International Standard on Quality Control 1, Quality Control for Firms that Perform Audits and Reviews of Financial Statements, and Other Assurance and Related Services Engagements and accordingly maintains a comprehensive system of quality control including documented policies and procedures regarding compliance with ethical requirements, professional standards and applicable legal and regulatory requirements.

Practitioner's Responsibilities

Our responsibility is to express an opinion, as required by Commission Delegated Regulation (EU) 2019/980 about whether the pro forma financial information has been compiled by the Board of Directors and Management of the Company on the basis of the applicable criteria.

We conducted our engagement in accordance with International Standard on Assurance Engagements (ISAE) 3420, Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus, issued by the International Auditing and Assurance Standards Board. This standard requires that the practitioner comply with ethical requirements and plan and perform procedures to obtain reasonable assurance about whether the Company has compiled the pro forma financial information on the basis of accounting and relevant accounting policies described in the Unaudited Pro Forma Financial Information section 11.3. Our work primarily consisted of comparing the unadjusted financial information with the source documents as described in section 11.3 of the Unaudited Pro Forma Financial Information, considering the evidence supporting the adjustments and discussing the Pro Forma Financial Information with Management of the Company.

The aforementioned opinion does not require an audit of historical unadjusted financial information, the adjustments to conform the accounting policies of the acquired entity to the accounting policies of the Company, or the assumptions summarized in section 11.3 of the Unaudited Pro Forma Financial Information. For purposes of this engagement, we are not responsible for updating or reissuing any reports or opinions on any historical financial information used in compiling the pro forma financial information, nor have we, in the course of this engagement, performed an audit or review of the financial information used in compiling the pro forma financial information.

The purpose of pro forma financial information included in a prospectus is solely to illustrate the impact of the Transaction on unadjusted financial information of the Company as if the Transaction had occurred or had been undertaken at an earlier date selected for purposes of the illustration. Because of its nature, the pro forma financial information addresses a hypothetical situation and, therefore, does not represent the Company's actual financial position or performance. Accordingly, we do not provide any assurance that the actual outcome of the Transaction for the financial performance periods ended 31 December 2020 and 30 June 2021 would have been as presented.

A reasonable assurance engagement to report on whether the pro forma financial information has been compiled on the basis of the applicable criteria involves performing procedures to assess whether the applicable criteria used by the Board of Directors and Management of the Company in the compilation of the pro forma financial information provide a reasonable basis for presenting the significant effects directly attributable to the event or transaction, and to obtain sufficient appropriate evidence about whether:

- The related unaudited pro forma adjustments give appropriate effect to those criteria; and
- The unaudited pro forma financial information reflects the proper application of those adjustments to the unadjusted financial information.
- The unaudited pro forma financial information has been compiled on a basis consistent with the accounting policies of the Company.

The procedures selected depend on the practitioner's judgment, having regard to the practitioner's understanding of the nature of the company, the event or transaction in respect of which the pro forma financial information has been compiled, and other relevant engagement circumstances.

The engagement also involves evaluating the overall presentation of the pro forma financial information.

We believe that the evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Opinion

In our opinion:

a) the pro forma financial information has been properly compiled on the basis stated in Section 11.3 in the Unaudited Pro Forma Financial Information.

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

This report is issued for the sole purpose of offering of shares in Norway and the admission of shares on the Oslo Stock Exchange, and other regulated markets in the European Union or European Economic Area. Therefore, this report is not appropriate in other jurisdictions and should not be used or relied upon for any purpose other than the listing of shares of the Company on the Oslo Stock Exchange or other regulated markets in the European Union or European Economic Area.

Oslo, 12 November 2021

BDO AS

Børre Skisland
State Authorized Public Accountant (Norway)

APPENDIX G:

PRO FORMA FINANCIAL INFORMATION

1. UNAUDITED PRO FORMA FINANCIAL INFORMATION

1.1. Introduction

During 2019 and 2020, the Group announced transactions to acquire licence interests for projects in Nigeria (completion is subject to governmental approval in Nigeria) and Guinea-Bissau (transaction completed in May 2021). If the last annual audited financial statements are used to assess the indicative impact the transactions have on the Group, both transactions would individually and combined cause a significant gross change for the Group.

The following unaudited pro forma financial information has been prepared using PetroNor Australia's consolidated financial statements and Financial Information. The implementation of the Scheme will be treated as a continuance of business under the Company (being the new listing entity). The financial statements for the Company going forward will be presented as a continuance of the activities of the Australian company PetroNor Australia.

1.2. Aje transaction

1.2.1. Transaction details

As announced on 21 October 2019, the Company entered into the Panoro Agreement for the acquisition of certain companies holding interests in OML-113 offshore Nigeria, containing the Aje Field. The Panoro Agreement contemplates the acquisition of 100% of the shares of PPSH and PPNH, which currently hold 100% of the shares in Pan-Petroleum Aje Limited, which participates in the exploration for and production of hydrocarbons in OML-113.

The consideration payable by the Group under the Panoro Agreement is (i) issue of shares in the Company for USD 10 million and (ii) a contingent payment obligation after PetroNor has recovered all costs related to the accumulated investments incurred after the Completion Date equal to USD 0.10 per 1,000 Cubic Feet of Aje Gas sales volume limited to USD 16.67 million.

In parallel, the Company concluded the YFP Agreement to create a SPV that will see such entity assume the lead technical and management role in the next phases of the Aje Field development. PetroNor and YFP will hold respectively 45% and 55% of the SPV shares, and the ability to appoint up to two directors each. The SPV will require two directors jointly to sign on its behalf, of which one is appointed by PetroNor and one appointed by YFP. The SPV will include the current license ownerships of YFP (the operator), YFP-DW and Panoro.

Together these agreements provide the framework and pathway towards sanctioning of the next phases of the Aje Field development in order to unlock its significant value through accessing the substantial proven gas and liquid in place reserves.

The completion of the Aje Transaction is subject to the satisfaction of certain conditions precedents, including the regulatory approval of the Nigerian Department of Petroleum Resources and consent of the Minister of Petroleum Resources.

The regulatory approval process in Nigeria is well underway but has been delayed by the impact of the COVID-19 pandemic. Originally set at 31 December 2020, Panoro and the Company agreed to amend the long stop date for closing of the Panoro Agreement to the 30 November 2021 which is the date by which authorisation of the Nigerian Department of Petroleum Resources and the consent of the Nigerian Minister of Petroleum Resources are required to have been received.

Upon the successful completion of the Aje Transaction, the Group will in the OML-113 licence acquire a nominal participating interest on 34 % and a revenue interest on 24.3%. These figures are based on the Group holding a 45% equity interest in the SPV, which in turn holds nominal licence interest on 75.5 % and a revenue licence interests on 54.1%. The table below shows all CAPEX, OPEX, and revenue for the SPV. PetroNor's interest is 45% relating to each figure.

The proportional allocation of operating expenditures and capital expenditures deviate from pro-rata allocation of revenues. Allocation of operating expenditures and capital expenditures are based on the following mechanic which were established in the Farm-In Agreements and Joint Operating Agreements in 2007.

SPV Aje Production	**Period 1:** Prior to YFP Payout		**Period 2:** Post YFP Payout		**Period 3:** Post Project Payout		
Participation Interest	CAPEX and OPEX	Revenue (cost recovery and profit sharing)	CAPEX and OPEX	Revenue (cost recovery and profit sharing)	CAPEX	OPEX	Revenue (cost recovery and profit sharing)
75.50%	38.755%	54.066%	38.755%	38.755%	38.755%	54.066%	54.066%

As of the date of this Prospectus, the licence is in "Period 1" and the commencement of "Period 2" is subject to YFP receiving USD 30 million in net proceeds. This is the cost incurred by YFP in OML-113 prior to the first farming agreement in 2007. YFP has received USD 12 million and the recovery of an additional USD 18 million is required for commencement of "Period 2". Based on the expectations of the management of the Company, this is expected to be incurred in about 2 years. The commencement of "Period 3" is subject to the net proceeds less the prior costs exceeding the cumulative expenditure. Based on the expectations of the management of the Company, this is expected to take place in about 3 to 4 years.

1.2.2. Aje Transaction Accounting Treatment

The conditions precedent for completion of both the Panoro Agreement and YFP Agreement are interlinked; and accounting wise, the Company regard that the Aje Transaction should be considered as one event, and not the acquisition and immediate disposal of PPSH and PPNH.

The Company expects to classify its interest in the new special purpose vehicle Aje Production as a 'joint venture' under IFRS 11 and will account for the investment using the equity method, whereby the initial investment is 2pprox.22d at cost and the carrying amount is increased or decreased 2pprox.22d2 the Company's share of profit or loss at each future period end.

Under the terms of the Panoro Agreement, the Company shall, either pay a cash consideration of USD 10 Million or issue consideration shares which in aggregate shall represent a total value of USD 10 Million to Panoro for the 100% equity share acquisition of PPSH and PPNH and their associated interest in OML-113, before the transfer of these PPSH and PPNH shares into Aje Production with YFP.

The Company anticipates to issue shares to conclude the Aje Transaction, thereby initially increasing non-current assets and equity by USD 10 million.

The Company will pay Panoro a conditional consideration of USD 0.10 per 1,000 cubic feet of the Aje Natural Gas Sales Volume (the "**Conditional Consideration**"). The Conditional Consideration will only be payable after Pan Aje has recovered all costs, both investments and operating costs, in relation to the gas production and the Conditional Consideration shall not exceed USD 16.67 million in cumulated payments.

1.2.3. Financial Information

The Aje Transaction involves the combination of six legal entities located in four different legal jurisdictions. Of which three entities have separate participating interests in the OML-113 lease in Nigeria and varying levels of economic interest.

Meaningful historical financial statements are not yet available for all entities involved in the Aje Transaction. Although the Company has received recent guidance and copy billing statements from the operator on the overall OML-113 operations. The separate entities that hold the participating interests may have additional corporate costs in addition to their respective license interest; and applying available financial numbers from one partner to pro rata estimate the figures for the total interest acquired may lead to incorrect information when combining financial information. Therefore, the Company is of the opinion that the only way to accurately reflect the Aje

Transaction in this Prospectus is by providing narrative information. As such there is no report by independent accountants or auditors in relation to the Aje Transaction.

Due to the drop in oil price in 2020, the existing joint venture partners negotiated reduced lease rate for the FPSO currently in operation at the Aje Field. The rates agreed were heavily discounted on a sliding scale that was based on the actual selling price of oil. This has benefited the joint venture partners during the period of extreme low prices in 2020. The discount is now minimal with the recovery of the oil prices close to levels before the COVID pandemic. The contract for the FPSO is up for renegotiation during Q4 2021.

When the Aje Transaction completes, the Company will have to recognise its share of any losses incurred in the period since the locked box dates. Any losses to be recognised would reduce the carrying value of the initial investment in the SPV. Based on joint venture billing information for the period since the locked box dates, the Company estimates the carrying value of investments may be reduced by USD 3 – 5 million. However, the Company considers the underlying value of the investment to be realised through the planned re-development of the Aje Field, and not based on current production operations.

The average production in 2021 has dropped from 1980 Bopd in 2020 to around 1400 Bopd. This has resulted in drop of revenue and slowed any financial recovery to the joint venture account.

Until the approval of the Aje Transaction by the DPR and overall completion, the Company does not have influence over the operations of OML-113.

Legal and due diligence costs in connection with the Panoro Agreement and the YFP Agreement were expensed as arose in 2019. In 2020 and first six months of 2021, the company continued to use existing internal staffing to develop redevelopment plans for the Aje Field pending completion of the Aje Transaction, where these costs have been expensed as occurred.

Legal and travel costs incurred in 2019 and 2020 in relation to the Aje project are estimated at USD 300,000.

1.3. Guinea-Bissau transaction

On 20 November 2020, the Group announced the 100% share purchase of the entity SPE Guinea Bissau AB[1] (the "**GB Transaction**"), which subsequently completed on 4 May 2021. The GB Transaction allowed PetroNor to assume the Operatorship (and interest of 78.57%) of the Sinapa (Block 2) and Esperança (Blocks 4A and 5A) licences in Guinea-Bissau.

The SEK 434,238 consideration paid in the transaction equalled the carrying amount of the net assets. In addition to the consideration paid, the Group paid USD 1.9 million in settlement of a payable balance to Svenska Petroleum Exploration AB on behalf of SPE Guinea Bissau AB.

The exploration licences held by SPE Guinea Bissau AB do not currently generate income, however a farm out of one or both of the licences may generate cash inflow from the reimbursement of past exploration costs.

1.3.1. Purpose of the unaudited pro forma financial information

The Company has prepared the pro forma statement of comprehensive income for the six month period ended 30 June 2021 and for the twelve-month period ended 31 December 2020 so as to illustrate how the GB Transaction would have affected the Company had it been completed at 1 January 2021 or at 1 January 2020 respectively, and this hypothetical compilation may differ from the Group's actual financial position or results.

Apart from the GB Transaction, no other circumstances occurring after 30 June 2021 are covered by the pro forma financial information. The sources of the historical financial information included in the pro forma financial statements are:

[1] As of 4 June 2021, SPE Guinea Bissau AB formally changed its name to PetroNor E&P AB.

- For the Company, extracted from the PetroNor Australia audited consolidated financial statements as of 31 December 2020; and the PetroNor Australia unaudited consolidated interim financial statements as of 30 June 2021

- For SPE Guinea Bissau AB, extracted from the audited financial statements as of 31 December 2020 and derived from the unaudited management accounts and transactional history from 1 January 2021 to 30 April 2021.

As the GB transaction completed on the 4 May 2020, the PetroNor Australia unaudited consolidated interim financial statements as of 30 June 2021 already consolidates the results for SPE Guinea Bissau AB from 1 May 2021 to the 30 June 2021 into the consolidated financial statements. It is the results for SPE Guinea Bissau AB from 1 January 2021 to 30 April 2021 that must be adjusted to generate the pro forma information for the six-month period ended 30 June 2021.

The source documents used to prepare the pro forma financial statements are included in Appendix 3 together with the signed pro forma financial information.

1.3.2. Accounting principles

The underlying source financial information for the Group included in the pro forma financial information is extracted from Financial Statements that have been prepared under Australian Accounting Standards and also complies with IFRS as issued by the International Accounting Standards Board.

SPE Guinea Bissau AB prepares its respective financial statements in SEK and under Swedish GAAP in accordance with the Annual Accounts Act and the BFN's (The Swedish Accounting Standards Board's) general advice BFNAR 2012: 1, This standard was developed by the BFN based on the IFRS for SMEs Standard but with amendments and exceptions due to Swedish Law and 'Swedish practice' as well to reflect Swedish tax law. The Company has identified differences between the Company's accounting policies and those applied by SPE Guinea Bissau AB that would impact the pro forma financial information, these are detailed in Section 11.3.3 below.

In accordance with IFRS 3, a purchase price allocation (PPA) has been performed in which the identifiable assets, liabilities and contingent liabilities of SPE Guinea Bissau AB have been identified. The PPA in the unaudited pro forma condensed financial information is based on the fair value of acquired assets and liabilities as of the date of acquisition. Assets acquired consist of inventory (Well heads), intangible assets (Licenses), trade receivables and cash. Liabilities assumed consist of trade payables.

The SEK 434,238 consideration paid in the transaction equaled the carrying amount of the net assets. Hence, the PPA did not identify any excess values that would give rise to any pro forma adjustments in the unaudited pro forma condensed financial information.

With regards to applicable exchange rates used in the pro forma statements:

- In the Statement of Comprehensive Income for the period to 31 December 2020 transactions recorded to the income have been translated at an average exchange rate of SEK 9.2106 to USD 1.00.

- In the Statement of Comprehensive Income for the period to 30 June 2021 transactions recorded to the income have been translated at an average exchange rate for each month ranging from SEK 8.2947to SEK 8.5427 to USD 1.00.

The pro forma financial information has not been audited in accordance with Norwegian or International Standards on Auditing ("**ISAs**"). However, BDO AS, Munkedamsveien 45, Postboks 1704 Vika, 0121 Oslo, has issued a report on the Pro Forma financial information included in Appendix H hereto. The report is prepared in accordance with ISAE 3420 "Assurance Engagements to Report on the Compilation of Pro Forma Financial Information Included in a Prospectus". BDO AS is the auditor for the Company and was a component auditor for PetroNor Australia's independent auditor, BDO Audit (WA) Pty Ltd.

1.3.3. GB Transaction unaudited pro forma financial information

*Pro forma statement of comprehensive income for the year ended 31 December 2020**

USD '000s	**PetroNor E&P Ltd.**	**SPE Guinea Bissau AB**	**SPE Guinea Bissau AB translated**	**Accounting Policy adjustments**	***Notes***	**Pro Forma Adjustments**	***Notes***	**Pro Forma Consolidated**
	Audited USD *$'000*	*Audited SEK Kr'000s*	Unaudited USD *$'000*	Unaudited USD *$'000*		Unaudited USD *$'000*		Unaudited USD *$'000*
Revenue	67,543	-	-	-		-		67,543
Cost of Sales	(25,885)	-	-	-		-		(25,885)
Gross Profit	**41,658**	**-**	**-**	**-**		**-**		**41,658**
Other operating income	45	-	-	-				45
Impairment of intangible asset	-	*(319,431)*	(34,681)	-		34,433	*B1*	(248)
Administrative expenses	(12,376)	*(30,157)*	(3,274)	(508)	*A1*	-		(16,158)
Profit from operations	**29,327**	***(349,588)***	**(37,955)**	**(508)**		**34,433**		**25,297**
Finance Expenses	(2,606)	*(134)*	(15)	-		-		(2,621)
Finance income	-	*24*	3	-		-		3
Foreign exchange gain/loss	1,507	*1,899*	206	-		-		1,713
Group contribution received	-	*346,265*	37,594	(37,594)	*A2*	-		-
Profit/(loss) before tax	**28,228**	***(1,534)***	**(167)**	**(38,102)**		**34,433**		**24,392**
Tax Expense	(17,078)	-	-	-		-		(17,078)
Profit/ (loss) for the period	**11,150**	**(1,534)**	**(167)**	**(38,102)**		**34,433**		**7,314**
Other comprehensive income								
Exchange gains/(losses) arising on translation of foreign operations	(1,050)	-	(21)	(4,695)	*A2*	4,235	*B1*	(1,529)
Total comprehensive income/(loss)	**10,100**	***(1,534)***	**(188)**	**(42,797)**		**38,668**		**5,786**
Profit/Loss for the period attributable to:								
Equity holders of the parent	2,373	*(1,534)*	(167)	(38,102)		34,433		(1,463)
Non-controlling interests	8,777		-	-		-		8,777
	11,150	**(1,534)**	**(167)**	**(38,102)**		**33,925**		**7,314**
Total comprehensive income / (loss) attributable to:								
Equity holders of the parent	1,417	*(1,534)*	(188)	(42,797)		38,668		(2,897)
Non-controlling interests	8,683		-	-		-		8,683
	10,100	***(1,534)***	**(188)**	**(42,797)**		**38,668**		**5,786**

** The above table has been prepared on the basis that the acquisition transaction completed on 1 January 2020*

Note A1: Exploration expenses

SPE Guinea Bissau AB uses the 'successful efforts' method to account for exploration expenses, compared to the 'area of interest' method used by the Company. Consequently, SPE Guinea Bissau AB capitalizes exploration costs that would be expensed as incurred by the Group. The pro forma statements have been adjusted to reflect PetroNor Group accounting policies and costs capitalised in SPE Guinea Bissau AB during 2020 in the amount of SEK 4,678K have been expensed and reclassified according to PetroNor Group accounting policy. This is a one-off effect as SPE Guinea Bissau AB will adopt PetroNor Group accounting policies. Hence going forward exploration costs within SPE Guinea Bissau AB will be expensed in accordance with the "area of interest" method.

Note A2: Svenska Petroleum Exploration Aktiebolag shareholder contribution prior to acquisition

In 2020 SPE Guinea Bissau AB recognised a contribution from their parent entity Svenska Petroleum Exploration Aktiebolag in the amount of SEK 346,265,287. Under IFRS this contribution would have been accounted for as an equity contribution and not recognised as income. The GAAP adjustment in the comprehensive statement of income has been translated at the average exchange rate of SEK 9.2106 to USD 1.00. A GAAP adjustment has also been made for the related foreign currency translation difference. This is a one-off adjustment and not expected to have a continued impact.

Note B1: Exploration expenses

In the statement of comprehensive income for 2020 SPE Guinea Bissau AB recognized an impairment of fixed asset in the amount of SEK 319.4 million (USD 34.3 million) relating to the Sinapa Block 2 and Esperança Block 4a&5a. The fair value of these assets at the time of acquisition was SEK 1 and thus a pro-forma adjustment has been made to reflect that there would be no impairment loss in the consolidated financial statements for PetroNor in 2020 if the transaction was completed on January 1, 2020. A pro-forma adjustment has also been made for the related foreign currency translation difference. This is a one-off adjustment and not expected to have a continued impact.

*Pro forma statement of comprehensive income for the six month period ended 30 June 2021**

USD '000s	**PetroNor E&P Ltd**	**SPE Guinea Bissau AB**	**SPE Guinea Bissau AB translated**	**Accounting Policy adjustments**	***Notes***	**Pro Forma Adjustments**	***Notes***	**Pro Forma Consolidated**
	Six months ended 30 June 2021	Four months ended 30 April 2021	Four months ended 30 April 2021	Four months ended 30 April 2021		Four months ended 30 April 2021		Six months ended 30 June 2021
	Unaudited	*Unaudited*	Unaudited	Unaudited		Unaudited		Unaudited
	USD	*SEK*	USD	USD		USD		USD
	$'000	*Kr'000s*	*$'000*	*$'000*		*$'000*		*$'000*
Revenue	48,174	-	-	-		-		48,174
Cost of Sales	(16,832)	-	-	-		-		(16,832)
Gross Profit	**31,342**	**-**	**-**	**-**		**-**		**31,342**
Other operating income	-							-
Exploration expenses	(1,259)	-	-	-		-		(1,259)
Administrative expenses	(5,314)	*(1)*	-	(60)	*C1*	-		(5,374)
Profit from operations	**25,126**	***(1)***	**-**	**(60)**		**-**		**25,066**
Finance Expenses	(1,626)	*(37)*	(4)	-		-		(1,630)
Foreign exchange gain/loss	19	*(172)*	(29)	-		-		(10)
Profit/(loss) before tax	**23,519**	***(210)***	**(29)**	**(60)**		**-**		**23,426**
Tax Expense	(14,654)	-	-	-		-		(14,654)
Profit/ (loss) for the period	**8,865**	**(210)**	**(33)**	**(60)**		**-**		**8,772**
Other comprehensive income								
Exchange gains/(losses) arising on translation of foreign operations	(29)	-	-	-		-		(29)
Total comprehensive income/(loss)	**8,836**	***(210)***	**(33)**	**(60)**		**-**		**8,743**
Profit/Loss for the period attributable to:								
Equity holders of the parent	3,029	*(210)*	(33)	(60)		-		2,936
Non-controlling interests	5,836	-	-	-		-		5,836
	8,865	**(210)**	**(33)**	**(60)**		**-**		**8,772**
Total comprehensive income / (loss) attributable to:								
Equity holders of the parent	3,258	*(210)*	(33)	(60)		-		3,165
Non-controlling interests	5,578	-	-	-		-		5,578
	8,836	***(210)***	**(33)**	**(60)**		**-**		**8,743**

** The above table has been prepared on the basis that the acquisition transaction completed on 1 January 2021. The GB transaction actually completed on 4 May 2021,and the statement of comprehensive income for the six months ending 30 June 2021 for PetroNor E&P Ltd includes SPE Guinea Bissau AB from 1 May 2021. Therefore the results of SPE Guinea Bissau AB from 1 January 2021 to 30 April 2021 have been added to the consolidated financial statements to 30 June 2021 to generate the unaudited pro forma financial information.*

Note C1: Exploration expenses

SPE Guinea Bissau AB uses the 'successful efforts' method to account for exploration expenses, compared to the 'area of interest' method used by the Company. Consequently, SPE Guinea Bissau AB capitalizes exploration costs that would be expensed as incurred by the Group. The pro forma statements have been adjusted to reflect PetroNor Group accounting policies and costs capitalised in SPE Guinea Bissau AB during 2021 in the amount of SEK 513K have been expensed and reclassified according to PetroNor Group accounting policy. In accordance with Group policy these types of exploration costs will continue to be expensed. This is a one-off effect as SPE Guinea Bissau AB will adopt PetroNor Group accounting policies.

1.3.4. Independent assurance report on unaudited pro forma financial information

With respect to the unaudited pro forma financial information included in this Prospectus, BDO AS has applied assurance procedures in accordance with ISAE 3420 "Assurance Engagement to Report Compilation of Pro Forma Financial Information Included in a Prospectus" in order to express an opinion as to whether the unaudited pro forma financial information has been properly complied on the basis stated, and that such basis is consistent with the accounting policies of the Company. BDO AS has issued an independent assurance report on the unaudited pro forma financial information included as Appendix G to this Prospectus. There are no qualifications to this assurance report.

The Unaudited Pro Forma Financial Information was approved and authorised for issue by the Board of Directors on 12 November 2021

The Board of Directors of PetroNor E&P ASA

Eyas A. Alhomouz *Chair*	Gro Gauthun Kielland *Board member*	Ingvil Smines Tybring-Gjedde *Board member*
George Jens Soby Pace *Board member*		Joseph Iskander *Board member*

Company admitted to trading on Oslo Børs

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