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Panoro Energy ASA

(Incorporated in Norway as a public limited liability company)
Registration number: 994 051 067)

Prospectus in connection with

Listing of 15,580,000 Placement Shares resolved issued in the Private Placement, each Placement Share having a face value of NOK 0.05 and subscribed at subscription price of NOK 16.10, raising gross proceeds of NOK 250,838,000.

THE PLACEMENT SHARES HAVE NOT BEEN AND WILL NOT BE REGISTERED UNDER THE U.S. SECURITIES ACT OF 1933, AS AMENDED (THE "SECURITIES ACT").

THE DISTRIBUTION OF THIS PROSPECTUS IN OTHER JURISDICTIONS MAY BE RESTRICTED BY LAW, AND PERSONS INTO WHOSE POSSESSION THIS PROSPECTUS COMES SHOULD INFORM THEMSELVES ABOUT, AND OBSERVE, ANY SUCH RESTRICTIONS. BY ACCEPTING THIS PROSPECTUS YOU AGREE TO BE BOUND BY THE FOREGOING INSTRUCTIONS.

THIS PROSPECTUS SERVES AS A LISTING PROSPECTUS AND NO SHARES OR OTHER SECURITIES ARE BEING OFFERED OR SOLD IN ANY JURISDICTION PURSUANT TO THIS PROSPECTUS.

SEE "RISK FACTORS" IN SECTION 2 FOR A DISCUSSION OF CERTAIN MATTERS THAT SHOULD BE CONSIDERED IN CONNECTION WITH AN INVESTMENT IN THE SHARES OF THE COMPANY.

Managers

Pareto Securities AS Sparebank1 Markets AS

14 December 2018

Important information

This Prospectus has been prepared in order to provide information about Panoro Energy ASA ("**Panoro Energy**", "**Panoro**" or the "**Company**") and its business in connection with the listing (the "**Listing**") on Oslo Børs of 15,580,000 shares (the "**Placement Shares**") issued in the private placement announced on 7 November 2018 and resolved by the extraordinary general meeting on 29 November 2018 (the **"Private Placement"**).

For the definitions of terms used throughout this Prospectus, see Section 17 "*Definitions and glossary*".

The Company has furnished the information in this Prospectus. Pareto Securities AS and Sparebank1 Markets AS (the "**Managers**") make no representation or warranty, expressed or implied, as to the accuracy or completeness of such information, and nothing contained in this Prospectus is, nor shall be relied upon as, a promise or representation by the Managers. This Prospectus has been prepared to comply with the Securities Trading Act of 29 June 2007 no. 75 ("Verdipapirhandelloven") (the ("**Norwegian Securities Trading Act**") and the Norwegian Regulation on Contents of Prospectuses, which implements the Prospectus Directive (EC/2003/71), including the Commission Regulation EC/809/2004, in Norwegian law. The Norwegian Financial Supervisory Authority has reviewed and approved (approval date: 14 December 2018) this Prospectus in accordance with the Norwegian Securities Trading Act sections 7-7 and 7-8. The Norwegian Financial Supervisory Authority has not made any form of control or approval relating to corporate matters described in or otherwise covered by this Prospectus. This Prospectus has been published in an English version only.

All inquiries relating to this Prospectus should be directed to the Company or the Managers. No other person has been authorised to give any information about, or make any representation on behalf of, the Company in connection with the Listing, and, if given or made, such other information or representation must not be relied upon as having been authorised by the Company or the Managers.

The information contained herein is as of the date hereof and subject to change, completion or amendment without notice. There may have been changes affecting the Company or its subsidiaries subsequent to the date of this Prospectus. Any new material information and any material inaccuracy that might have an effect on the assessment of the Placement arising after the publication of this Prospectus and before the Listing will be published as a supplement to this Prospectus in accordance with section 7-15 of the Norwegian Securities Trading Act. Neither the delivery of this Prospectus nor the Listing at any time after the date hereof will, under any circumstances, create any implication that there has been no change in the Company's or its subsidiaries' affairs since the date hereof or that the information set forth in this Prospectus is correct as of any time since its date.

The contents of this Prospectus shall not be construed as legal, business or tax advice. Each reader of this Prospectus should consult its own legal, business or tax advisor as to legal, business or tax advice. If in any doubt about the contents of this Prospectus, readers should consult their stockbroker, bank managers, lawyer, accountant or other professional adviser.

In the ordinary course of their respective businesses, the Managers and certain of its affiliates have engaged, and may continue to engage, in investment and commercial banking transactions with the Company and its subsidiaries. Without limiting the manner in which the Company may choose to make any public announcements, and subject to the Company's obligations under applicable law, announcements relating to the matters described in this Prospectus will be considered to have been made once they have been received by Oslo Børs and distributed through its information system.

Unless otherwise indicated or the context otherwise requires, all references in this Prospectus to "**Panoro Energy**", "**Panoro**", or the "**Company**" are to Panoro Energy ASA and its consolidated subsidiaries.

Investing in the Company's Shares involves risks. See Section 2 "Risk Factors" of this Prospectus.

The distribution of this Prospectus may be restricted by law in certain jurisdictions. This Prospectus may not be used for the purpose of, and does not constitute, an offer to sell or issue, or a solicitation of an offer to buy or subscribe for, any securities in any jurisdictions in any circumstances in which such offer or solicitation is not lawful or authorized. The Company and the Manager require persons in possession of this Prospectus inform themselves about and to observe such restrictions.

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1. SUMMARY

*The following summary of the information and consolidated financial and other data appearing elsewhere in this Prospectus is qualified in its entirety by such more detailed information set forth elsewhere herein and in the documents incorporated hereto by reference, see Section 15.2 "*Documents Incorporated by Reference*". This summary does not contain all of the information that may be important to potential investors and it should be read as an introduction to the Prospectus. Potential investors should review carefully the entire Prospectus, including the risk factors and the more detailed financial and other data included herein or incorporated hereto by reference, before making an investment decision (financial data is available on www.panoroenergy.com). Following the implementation of the relevant provisions of the Prospectus Directive (EC/2003/71) in each member state of the European Economic Area ("**EEA**") in which an offer which is subject to the Prospectus Directive is conducted, no civil liability will attach to the responsible persons in any such member state solely on the basis of this summary, including any translation thereof, unless it is misleading, inaccurate or inconsistent when read together with the other parts of this Prospectus. Where a claim relating to the information contained in this Prospectus is brought before a court in a member state of the EEA, the plaintiff may, under the national legislation of the member state where the claim is brought, be required to bear the costs of translating this Prospectus before the legal proceedings are initiated.*

Section A – Introduction and Warnings

A.1	Warning	This summary should be read as an introduction to the Prospectus. Where a claim relating to the information contained in the Prospectus is brought before a court, the plaintiff investor might, under the national legislation in its Member State, 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 if the summary is misleading, inaccurate or inconsistent when read together with the other parts of the Prospectus or 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.
A.2	Resale and final placement by financial intermediates	Not applicable; no consent is granted by the Company for the use of this Prospectus for subsequent resale or final placement of the shares.

Section B – Issuer

B.1	Legal and commercial name	Panoro Energy ASA
B.2	Domicile and legal form, legislation and country of incorporation	Panoro Energy is a public limited liability company organised under the laws of Norway and subject to the Norwegian Public Limited Liability Companies Act of 13 June 1997 no. 45 ("Allmennaksjeloven") (the "**Norwegian Public Limited Liability Companies Act**"). Panoro Energy was incorporated on 28 April 2009 under the name Startup 387 09 AS and was later renamed to New Brazil Holding ASA. The Company was renamed to Panoro Energy ASA on 1 June 2010. Panoro's

		registered organization number is 994 051 067.
B.3	Current operations, principal activities and markets	Panoro Energy ASA is an independent exploration and production ("**E&P**") company based in London and listed on the Oslo Stock Exchange with ticker PEN. The Company holds exploration and development assets in North and West Africa, namely the Dussafu License offshore southern Gabon, Oil Mining License 113 offshore western Nigeria, Sfax Offshore Exploration Permit and Ras El Besh Concession Tunisia. The Company's strategy is to become a full cycle exploration and production company with main focus on North and West Africa. Panoro's active assets and operations comprise[1)]: i) Aje Field Nigeria in License OML 113: a non-operated 6.502% equity interest (16.255% paying interest and 12.1913% revenue interest). The Company is invested in the Aje development which consists of two producing wells in the Aje field producing into a Floating Production Storage and Offloading ("**FPSO**"). ii) Dussafu Marin License: a non-operated 8.33% interest in a license offshore Gabon. The license contains the Tortue field, which started production from 2 wells in 2018, and contains gross economic 2P reserves of 23.5 MMbbls of oil. Additional contingent and prospective resources have been identified on the license. iii) Sfax Offshore Exploration Permit: an operated 87.5% interest in an exploration permit offshore Tunisia. iv) Ras El Besh Concession: an operated 87.5% interest in an exploitation concession within the Sfax Offshore Exploration Permit. 1) The percentages in relation to i) and ii) are the interests held by Panoro's subsidiaries involved in each of the projects.
B.4a	Significant recent trends	The Company is not aware of any trends, uncertainties, demands, commitments or events that could have a material effect on the Group's prospects for the current financial year.
B.5	Description of the Group	The Group consists of Panoro Energy ASA, which is the parent company and the following: <u>Subsidiaries</u> - Panoro Energy do Brasil Ltda - Panoro Energy Limited - African Energy Equity Resources Limited - Pan-Petroleum (Holding) Cyprus Limited - Pan-Petroleum Holding B.V. - Pan-Petroleum Gabon Holding B.V. - Pan-Petroleum Gabon B.V. - Pan-Petroleum Nigeria Holding B.V. - Pan-Petroleum Services Holding B.V. - Panoro Energy Tunisia B.V. - Pan-Petroleum Aje Limited ("**PPAL**") - Energy Equity Resources Aje Limited - Energy Equity Resources Oil and Gas Limited - Syntroleum Nigeria Limited

- PPN Services Limited
- Panoro Energy Gabon Production SA
- Energy Equity Resources (Cayman Islands) Limited
- Energy Equity Resources (Nominees) Limited

Jointly controlled companies
- Sfax Petroleum Corporation AS
- Panoro Energy AS
- Panoro Tunisia Exploration AS
- Panoro Tunisia Production AS
- *OMV Tunisia Upstream GmbH (to be acquired subject to completion of OMV Transaction)

Joint operating company
- *Thyna Petroleum Services SA (to be acquired subject to completion of the OMV Transaction) (50%)

B.6 Interests in the Company and voting rights

The 20 largest shareholders in Panoro Energy ASA as at 14 December 2018 are shown in the table below:

#	Shareholder	Share holding	Share %
1	F2 FUNDS AS	3,674,229	5.89
2	SPAREBANK 1 MARKETS MARKET-MAKING	2,795,031	4.48
3	J.P. Morgan Securiti A/C CUSTOMER SAFE KE	2,650,444	4.25
4	DNO ASA	2,641,465	4.23
5	SKANDINAVISKA ENSKIL	2,484,472	3.98
6	SUNDT AS	1,614,906	2.59
7	Danske Invest Norge	1,590,785	2.55
8	HORTULAN AS	1,446,578	2.32
9	STOREBRAND VEKST VER	1,192,247	1.91
10	JPMORGAN EUROPE LTD, SPAREBANK 1 MARKETS MEGLERKONTO	1,064,174	1.71
11	KLP AKSJENORGE	938,462	1.50
12	MATHIAS HOLDING AS PER MATHIAS AARSKOG	848,447	1.36
13	PREDATOR CAPITAL MAN	796,024	1.28
14	PARETO SECURITIES AS EMISJONSKONTO INNLAN	768,769	1.23
15	KOMMUNAL LANDSPENSJO	705,203	1.13
16	ALDEN AS	696,894	1.12
17	KAMPEN INVEST AS	624,223	1.00
18	NORDNET LIVSFORSIKRI	600,238	0.96
19	SVOREN STEINAR	594,000	0.95
20	Nordnet Bank AB	576,643	0.92

B.7 Selected historical key financial information

The following historical financial data has been extracted from the audited 2015, 2016 and 2017 consolidated financial statements of Panoro. The nine months ended 30 September 2018 unaudited historical information has been obtained from the unaudited interim consolidated financial statements of Panoro published in the 2018 third quarter report.

Consolidated income statement

US$ 000	3 months ended 30 September 2018 *(Unaudited)*	3 months ended 30 September 2017 *(Unaudited)*	9 months ended 30 September 2018 *(Unaudited)*	9 months ended 30 September 2017 *(Unaudited)*	12 months ended 31 December 2017 *(Audited)*	12 months ended 31 December 2016 *(Audited)*	12 months ended 31 December 2015 *(Audited)*
Total revenue and income	2,642	3,117	7,267	4,941	6,518	5,461	-
Total Operating expenses	(5,497)	(3,640)	(12,386)	(36,812)	(42,474)	(67,354)	(39,273)
Discontinued operations	(2,997)	(576)	(5,598)	(32,144)	(36,589)	(62,636)	(39,867)
Net income / (loss)	(2,997)	(577)	(5,601)	(32,147)	(36,592)	(62,646)	(39,886)

Consolidated statement of financial position

US$ 000	As at 30 September 2018 *(Unaudited)*	As at 31 December 2017 *(Audited)*	As at 31 December 2016 *(Audited)*	As at 31 December 2015 *(Audited)*
Total current assets	24,348	9,830	7,175	12,641
Total non-current assets	37,373	25,428	51,547	102,455
Total assets	61,721	35,258	58,722	115,096
Total current liabilities	16,177	6,810	2,381	693
Total non-current liabilities	26,040	11,128	2,013	6,232
Total liabilities	42,217	17,938	4,394	6,925

Consolidated statement of cash flows

US$ 000	3 months ended 30 September 2018 *(Unaudited)*	3 months ended 30 September 2017 *(Unaudited)*	9 months ended 30 September 2018 *(Unaudited)*	9 months ended 30 September 2017 *(Unaudited)*	12 months ended 31 December 2017 *(Audited)*	12 months ended 31 December 2016 *(Audited)*	12 months ended 31 December 2015 *(Audited)*
Net cash generated from / (used in) operating activities	(1,650)	(1,342)	(4,002)	(438)	(1,952)	(2,638)	(6,532)
Net cash provided by / (used in) investing activities	7,152	-	7,152	4,052	5,052	(11,804)	(23,511)
Net cash provided by / (used in) financing activities	8,457	(509)	9,976	(1,552)	(1,554)	8,272	59
Foreign currency adjustments	1	4	(2)	3	3	(10)	(9)
Cash and cash equivalents at beginning of the period	5,481	8,680	6,317	4,768	4,768	10,948	40,941
Cash and cash equivalents at end of the period	19,441	6,833	19,441	6,833	6,317	4,768	10,948

B.8	Selected key pro forma financial information	The following table sets out certain selected key unaudited Pro Forma Financial Information for the group for the year ended 31 December 2017. On 7 November 2018, Panoro Tunisia Production AS signed an agreement with OMV Exploration & Production GmbH to acquire 100% of the shares in OMV Tunisia Upstream GmbH ("**OMV Tunisia**"). OMV Tunisia holds a 49% interest in five oil production concessions in Tunisia and 50% of Thyna Petroleum Services SA, which serves as the operating company for the concessions ("**OMV Transaction**"). The unaudited Pro Forma Information set out below has been prepared by the Company for illustrative purposes to show how the OMV Transaction might have affected the Company's statement of financial position at 31 December 2017 if the OMV Transaction occurred at the balance sheet date. No pro forma profit and loss financial information has been prepared as if the Transactions were completed on 1 January 2017, due to the following reasons: • OMV Tunisia, for 2017, lacks allocation of company overhead costs and other items required to provide a complete and relevant income statement; and • The assets have been carved out from the Seller's own books and due to confidentiality restrictions, the Company does not have access to the necessary historical information to extract relevant historical income statement financial information for 2017.

(US $ '000)	Panoro Energy ASA (consolidated) IFRS 31/12/2017	OMV Tunisia Upstream GmbH IFRS 31/12/2017 (unaudited)	Pro forma adjustments 31/12/2017 (unaudited)	Notes	Pro forma 31/12/2017 (unaudited)
ASSETS					
Non-current assets					
Intangible assets					
Goodwill	-	-	16,589	(a)	16,589
Licenses and exploration assets	13,596	-	-		13,596
Production rights	-	-	29,104	(a)	29,104
Total intangible assets	**13,596**	**-**	**45,693**		**59,289**
Tangible assets					
Production assets and equipment	9,902	19,556	-		29,458
Development assets	1,694	553	-		2,247
Property, furniture, fixtures and equipment	102	-	-		102

(US $ '000)	Panoro Energy ASA (consolidated) IFRS 31/12/2017	OMV Tunisia Upstream GmbH IFRS 31/12/2017 (unaudited)	Pro forma adjustments 31/12/2017 (unaudited)	Notes	Pro forma 31/12/2017 (unaudited)
Deferred tax assets	-	3,083	-		3,083
Other non-recurrent assets	134	-	-		134
Total tangible assets	**11,832**	**23,192**	**-**		**35,024**
Total non-current assets	**25,428**	**23,192**	**45,693**		**94,313**
Current assets					
Crude oil inventory	1,398	453	-		1,851
Inventories	-	3,871	-		3,871
Trade and other receivables	615	2,587	-		3,202
Cash and cash equivalents	6,317	-	**9,336**	(e)	15,653
Restricted cash	1,500	-	-		1,500
Total current assets	**9,830**	**6,911**	**9,336**		**26,077**
TOTAL ASSETS	**35,258**	**30,103**	**55,029**		**120,390**
EQUITY AND LIABILITIES					
Equity					
Share capital	299	25	68	(a), (b), (e)	392
Share premium	297,490	-	28,007	(b),(d), (e)	325,497
Treasury shares	(503)	-	-		(503)
Additional paid-in capital	122,205	3,576	(3,576)	(a)	122,205
Total paid-in equity	**419,491**	**3,601**	**24,499**		**447,591**
Other reserves	(43,405)	-	-		(43,405)
Retained earnings	(358,766)	-	(1,997)	(a),(c),(d)	(360,763)
Total equity attributable to shareholder of the parent	**17,320**	**3,601**	**22,502**		**43,423**
Non-current liabilities					
Decommissioning liability	2,039	17,063	-		19,102
Long-term liabilities	2,197	-	15,938	(c)	18,135
Deferred tax liabilities	-	3,226	16,589	(a)	19,815
Other non-current liabilities	6,892	905	-		7,797
Total non-current liabilities	**11,128**	**21,195**	**32,527**		**64,850**
Current liabilities					
Accounts payable and accrued liabilities	6,737	-	-		6,737
Corporation tax liability	73	5,307	-		5,380
Other current liabilities	-	-	-		-

(US $ '000)	Panoro Energy ASA (consolidated) IFRS 31/12/2017	OMV Tunisia Upstream GmbH IFRS 31/12/2017 (unaudited)	Pro forma adjustments 31/12/2017 (unaudited)	Notes	Pro forma 31/12/2017 (unaudited)
Total current liabilities	**6,810**	**5,307**	**-**		**12,117**
TOTAL EQUITY AND LIABILITIES	**35,258**	**30,103**	**55,029**		**120,390**

B.9	Profit forecast or estimate	Not applicable. The Company has not provided a profit forecast in this Prospectus.
B.10	Audit report qualifications	The Company's auditor is Ernst & Young AS ("**Ernst & Young**"). Ernst & Young has audited the Company's annual accounts for the fiscal years ended 31 December 2015, 2016 and 2017 and all audit opinions have been issued without qualifications.
B.11	Sufficient working capital	In the opinion of the Company, and taking into account the net proceeds from the Private Placement, the working capital for the Group is sufficient to meet the Group's working capital requirements for the next twelve months.

Section C – Securities

C.1	Type and class of securities admitted to trading and identification number	The Company has one class of Shares in issue and all shares provide equal rights in the Company. Each of the Shares carries one vote. The Company's tradable Shares have been created under the Norwegian Public Limited Companies Act and are registered in book-entry form with the VPS under International Securities Identification Number ("**ISIN**") NO NO0010564701.
C.2	Currency of issue	The Shares are issued in Norwegian Kroner ("**NOK**").
C.3	Number of shares in issue and par value	As at the date of this Prospectus the Company had a fully paid share capital of NOK 3,119,380 divided into 62,387,600 Shares, each with a par value of NOK 0.05.
C.4	Rights attaching to the securities	The Company has one class of shares. The Shares are equal in all respects, including the right to dividend; voting rights; rights to share in the issuer's profit; rights to share in any surplus in the event of liquidation; redemption provisions; reserves or sinking fund provisions; liability to further capital calls by the issuer; and any provision discriminating against or favoring any existing or prospective holder of such securities as a result of such shareholder owning a substantial number of shares. Each Share carries one vote at the Company's general meeting.

C.5	Restrictions on transfer	The shares are freely transferrable and, subject to the Articles of Association of the Company and any applicable securities law, there are no restrictions in the Company's securities.
C.6	Admission to trading	The Company's shares are listed on Oslo Børs. The Placement Shares are subject to application for admission to trading on Oslo Stock Exchange. The Company expects the Placement Shares will be listed on Oslo Stock Exchange on or about 17 December 2018. The Placement Shares will not be sought admitted to trading on any other regulated market than Oslo Stock Exchange.
C.7	Dividend policy	The Company's objective is to create lasting value and provide competitive returns to its shareholders through profitability and growth. Long-term returns to shareholders should reflect the value created in the Company in the form of increased share price as well as dividends. Dividends should arise in line with the growth in the Company's results while at the same time recognizing the need for financial preparedness for cyclical market movements, as well as opportunities for adding value through new profitable investments. Over time, value added will be reflected to a greater extent by an increased share price, rather than through dividend distributions. The Company has not paid any dividend since its incorporation in 2009.

Section D – Key Risks

D.1	Key risks specific to the Company or its industry	▪ The Company'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; ▪ Reserves and contingent resources included in the Prospectus are by their nature uncertain in respect of the inferred volume range; ▪ Developing a hydrocarbon production field requires significant investment and the Group's current and future development projects are associated with risks relating to delays, cost inflation, potential penalties and regulatory requirements; ▪ Several of the fields in which the Company has an interest have been producing for years. Producing oil and natural gas reservoirs, and particularly in the case of mature fields, are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Thus, the Company's future cash flow and results of operations are highly dependent upon the Company's success in

	efficiently developing and exploiting its current properties and economically finding or acquiring additional recoverable reserves; ▪ There are risks and uncertainties relating to extension of existing licenses and permits, in particular in Nigeria and Tunisia, including whether any extensions will be subject to onerous conditions and local authorities may impose additional financial or work commitments beyond those currently contemplated; ▪ Currently, all of the Company's production comes from two fields, Aje in Nigeria and Dussafu in Gabon, with the latter reaching first oil in September 2018. The OMV Transaction includes producing assets in Tunisia. Under any circumstance, the Company'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 Company, or new fields coming into production, it may have direct and significant impact on a substantial portion of the Company's production and hence the Company's revenue, profits and financial position as a whole; ▪ The Company will own the Tunisian assets in a joint venture with a third party and conflict of interests may occur; ▪ The Company faces risks related to decommissioning activities and related costs; ▪ The Company faces the risk of litigation or other proceedings in relation to its business and is subject to third-party risk in terms of operators and partners and conflicts within a license group, of which the now settled arbitration concerning the Aje joint venture is an example; ▪ The Company may not have access to necessary infrastructure or capacity booking for the transportation of oil and gas, and all transportation involve risks; ▪ The Company's ability to sell or transfer license interests may be restricted by regulatory consent requirements, provisions in its joint operating agreements including pre-emption rights, if any, applicable legislation or commercial issues; ▪ The Company may be subject to liability under environmental laws and regulations; ▪ The Company's business and financial condition could be adversely affected if tax regulations for the petroleum industry in jurisdictions which the Company operates are amended; ▪ The Company will have guarantee and indemnity

		obligations, both towards authorities and towards lenders and suppliers; ▪ The Company must use substantial time, attention and resources with respect to integration of the businesses acquired in Tunisia; ▪ The Company may experience conflicts of interest, inter alia because some of the directors, officers and principal shareholders of the Company are or may become engaged in other oil and gas interests (including interests relating to oil and gas services) on their own behalf and on behalf of other companies resulting in a conflict of interest or direct competition with the Company; ▪ The Company has a limited number of key employees and is subject to the risk of losing any such key employees; ▪ There are legal and security risks associated with jurisdictions in which the Company operates, including the risk that governments or local authorities may intervene in the oil and gas industry in ways that are unfavourable to the Company's business and strategy, and also risks specifically related to fraud, bribery and corruption; ▪ Climate change abatement legislation, protests against fossil fuel extraction and regulatory, technological and market improvements within the renewable energy sector may have a material adverse effect on the oil and gas industry; ▪ The Company is exposed to credit risk ▪ Existing debt is restrictive on the Company and the Company may have difficulties servicing debt in the future, and the Company is subject to time sensitive restructuring provisions as part of its debt financing plans; ▪ The Company's working capital needs are difficult to forecast and may be subject to significant and rapid increases which could result in additional financing requirements that the Company may not be able to obtain on satisfactory terms or at all.
D.2	Key risks specific to the securities	▪ *Potential dilution of shareholders* – Shareholders of the Company may suffer from dilution in connection with future issuances of Shares. ▪ *Restrictions on ownership and resale of the Shares* – The Shares are not qualified for sale in certain jurisdictions, including Canada and the United States, and as such may not be offered, sold or resold in these jurisdictions, directly or indirectly, unless an exemption is available. In addition, there can be no assurances that shareholders of the Company residing or domiciled in these jurisdictions will be able to

	participate in future capital increases. ▪ *Share price volatility and liquidity* - The share price of early-to-mid-stage companies comparable to Panoro can be highly volatile and shareholdings can be illiquid. Shares registered in nominee accounts - Beneficial owners of the Shares that are registered in a nominee account (e.g. through brokers, dealers or other third parties) may not be able to vote on such Shares unless their ownership is re-registered in their names with the VPS Register prior to the Company's General Meetings, or their beneficial ownership is confirmed by the nominee in time for the General Meetings.

Section E – The Offer

E.1	Net proceeds and estimated expenses	The transaction costs of the Company related to the Private Placement are estimated at approximately NOK 15.9 million (US$ 1.9 million), and accordingly the net proceeds of the Private Placement is approximately NOK 234.9 million. No expenses or taxes are charged to the subscribers in the Private Placement by the Company or the Managers.
E.2	Reasons for the Private Placement and use of proceeds	The Company's jointly controlled company, Panoro Tunisia Production AS (the "**Buyer**") has signed an agreement (the "**Agreement**") with OMV Exploration & Production GmbH (the "**Seller**") to acquire OMV Tunisia Upstream GmbH (the "**Target**"). The Target holds a 49% interest in five oil production concessions in Tunisia and 50% of Thyna Petroleum Services ("**TPS**") which serves as the operating company for the concessions. The acquisition price is $65 million (the "**Price**"), with an effective date of 1 January 2018, of which Panoro's interest is in the transaction is 60%. The net proceeds from the Private Placement will be used to finance the Company's 60% equity share of the acquisition of the Target, for oil and gas development projects particularly in Gabon and Tunisia as well as for general corporate purposes.
E.3	Terms and conditions of the offer	On 7 November 2018, the Company raised NOK 250,838,000 million in gross proceeds through a Private Placement of 15,580,000 Placement Shares, each with a par value of NOK 0.05 and a subscription price of NOK 16.10 per Placement Share. The Private Placement was directed towards professional and institutional investors, including certain existing shareholders of the Company. The Private Placement was approved by the Company's Extraordinary General Meeting on 29 November 2018 and the Placement Shares were registered with the Norwegian Register of Business Enterprises on 6 December 2018. The percentage of immediate dilution resulting from the Private Placement for the Company's shareholders is approximately 24.97 per cent. On the Extraordinary General Meeting held on 29 November 2018 it was resolved to conduct a subsequent offering of

		2,600,000 Offer Shares. On 11 December 2018, the board of directors cancelled a contemplated subsequent offering due to Panoro shares trading below NOK 13 per share since 19 November 2019, compared to the subscription price of NOK 16.10 per share for the subsequent offering.
E.4	Material and conflicting interests	Pareto Securities and SpareBank1 Markets AS serve as Managers in connection with the Private Placement and receive fees and commission in this regard. The Managers and its respective affiliates are currently providing, and may provide in the future, investment and commercial banking services to the Company and its affiliates in the ordinary course of business, for which they may receive and may continue to receive customary fees and commissions. The Managers, its respective employees and any affiliate may currently own Shares in the Company. Beyond the abovementioned, the Company is not aware of any interest of any natural or legal persons involved in the Private Placement that may have conflicting interest.
E.5	Selling shareholders and lock-up agreements	There are no selling Shareholders or lock-up agreements.
E.6	Dilution resulting from the Private Placement	Dilution for shareholders in the Company as of 6 November 2018 who did not participate of the Private Placementis approximately 24.97%.
E.7	Estimated expenses charged to investor	Not applicable. The Company will not charge any costs, expenses or taxes directly to any shareholder or to the investor in connection with the Private Placement.

2. RISK FACTORS

Potential investors should carefully consider each of the following risks and all of the information set forth in this Prospectus, including information incorporated hereto by reference, see Section 15.2 "Documents incorporated by reference", before deciding to invest in the shares. If any of the following risks and uncertainties develops into actual events, the Group's business, financial conditions, results of operations or cash flows could be materially adversely affected. In that case, the trading price of the shares could decline and potential investors may lose all or part of their investment. Potential investors should carefully consider each of the following risks and all of the information set forth in this Prospectus, including information incorporated hereto by reference, see Section 15.2 "Documents incorporated by reference", before deciding to invest in the shares. If any of the following risks and uncertainties develops into actual events, the Company's business, financial conditions, results of operations or cash flows could be materially adversely affected. In that case, the trading price of the shares could decline and potential investors may lose all or part of their investment.

2.1 RISKS RELATING TO THE COMPANY'S BUSINESS AND OPERATIONS

The Company'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 Company'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 Company'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 declines in recent years. Oil and gas prices are unstable and are subject to significant fluctuations for many reasons including, but not limited to;

- changes in global and regional supply and demand, and expectations regarding future supply and demand for oil and gas, even relatively minor changes;
- geopolitical uncertainty;
- availability of pipelines, tankers and other transportation and processing facilities;
- proximity to, and the capacity and cost of, transportation;
- petroleum refining capacity;
- price, availability and government subsidies of alternative fuels;
- price and availability of new technologies;
- the ability and willingness of the members of the Organization of the Petroleum Exporting Countries ("OPEC") and other oil-producing nations to set and maintain specified levels of production and prices;
- political, economic and military developments in producing regions, particularly the Middle East, Russia, Africa and Central and South America, and domestic and foreign governmental regulations and actions, including import and export restrictions, taxes, repatriations and nationalisations;
- global and regional economic conditions;
- trading activities by market participations and others either seeking to secure access to oil and gas or to hedge against commercial risks, or as part of investment portfolio activity;
- weather conditions and natural disasters; and
- terrorism or the threat of terrorism, war or threat of war, which may affect supply, transportation or demand for hydrocarbons and refined petroleum products.

Sustained lower oil and gas prices or price declines may inter alia lead to a material decrease in the Company's net production revenues.

The Company may from time to time enter into hedging arrangements in the form of put options to offset the risk of revenue losses if commodity prices decline. However, such arrangements may be expensive and there can be no assurance that hedging will be available or continue to be available on commercially reasonable terms. In addition, hedging itself carries certain risks, including expenses associated with terminating any hedging agreements.

Further, sustained lower oil and gas prices may also cause the Company to make substantial downward adjustments to its oil and gas reserves. If this occurs, or the Company's estimates of production or economic factors change, the Company 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. Further, certain development projects which are or become of substantial importance to the Company could become unprofitable as a result of a decline in price and could result in the Company having to postpone or cancel a planned project, or if it is not possible to cancel the project, carry out the project with negative economic impact. Additionally, if oil and gas prices remain depressed over time, it could reduce the Company's ability to raise new debt or equity financing or to refinance any outstanding loans on terms satisfactory, or at all.

Reserves and contingent resources are by their nature uncertain in respect of the inferred volume range

Included in this Prospectus is information relating to the reserves and resources of certain of the Company's assets and certain assets comprised by the Transaction. 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 be actually produced. 1P – Proven reserves represent volumes that will be recovered with 90% probability, 2P – Proven + Probable represent volumes that will be recovered with 50% probability and 3P – Proven + Probable + Possible represent 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 or where development is unlikely with present basic assumptions (e.g. due to the lack of a firm plan of development with the necessary partner or governmental approval, the lack of a market, or the lack of the proper delineation necessary to establish the size of the accumulation for commercial purposes), or under evaluation. Contingent resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves.

Many of the factors in respect of which assumptions are made when estimating reserves and resources are beyond the Company's control and therefore these assumptions may prove to be incorrect over time. For example, sustained lower oil and gas prices may cause the Company to make substantial downward adjustments to its oil and gas reserves and resources. If this occurs, or the Company's estimates of production or economic factors change, the Company 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.

Evaluations of reserves and resources necessarily involve multiple uncertainties. The accuracy of any reserves or resources evaluation depends on the quality of available information and petroleum engineering and geological interpretation. Exploration drilling, interpretation, testing and production after the date of the estimates may require substantial upward or downward revisions in the Company's reserves or resources data.

Moreover, different reservoir engineers may make different estimates of reserves and cash flows based on the same available data. Actual production, revenues and expenditures with respect to reserves and resources will vary from estimates, and the variances may be material. Also, effects of regulations adopted by governmental agencies, future operating costs, royalties, tax on the extraction of commercial minerals, development costs and well work-over and remedial costs represent further variables and assumptions which makes the estimation of reserves and resources uncertain and incorrect.

Special uncertainties exist with respect to the estimation of resources in addition to those set forth above that apply to reserves, such as:

- the quantities and qualities that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of additional exploration and future development expenditures;
- demand for oil and gas; and
- future oil and gas sales prices.

The probability that contingent resources will be economically developed, or be economically recoverable, is considerably lower than for proven, probable and possible reserves. Forward-looking statements contained in this Prospectus concerning the reserves and resources definitions should not be unduly relied upon by potential investors. If the assumptions upon which the estimates of the Issuer's oil and gas reserves or resources are based prove to be incorrect, the Company may be unable to recover and/or produce the estimated levels or quality of oil or gas set out in this Prospectus, which could have a material adverse effect on the Company's business, prospects, financial condition or results of operations.

Developing a hydrocarbon production field requires significant investment

The Company is currently involved in the development of fields in the Dussafu license in Gabon and, following completion of the Transaction, plans to be involved in developments in Tunisia.

Further, the Company may also become involved in other development projects, either in existing hydrocarbon assets or in hydrocarbon assets which may be acquired in the future.

Developing a hydrocarbon production field requires significant investment, sometimes over several decades, to build the requisite operating facilities, drilling of production wells along with implementation of advanced technologies for the extraction and exploitation of hydrocarbons with complex properties. Making these investments and implementing these technologies, normally under difficult conditions, can result in uncertainties about the amount of investment necessary, operating costs and additional expenses incurred as compared with the initial budget, thereby negatively affecting the business, prospects, financial condition and results of operations of the Company. Further, with respect to contingent resources, the amount of investment needed may be prohibitive, such that conversion of resources into reserves may not be commercially viable. The Company may be unable to obtain needed capital or financing on satisfactory terms. If the Company’s revenues decrease, it may have limited ability to obtain the capital necessary to sustain operations at current levels. If the Company’s available cash is not sufficient to fund its committed or planned investments, a curtailment of its operations relating to development of its business prospects could occur, which in turn could lead to a decline in its oil and natural gas production and reserves, or if it is not possible to cancel or stop a project, be legally obliged to carry out the project contrary to its desire or with negative economic impact. Further, the Company may inter alia fail to make required cash calls and thus breach license obligations, which again could lead to adverse consequences. All of the above may have a material adverse effect on the Company and its financial position.

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

The future success of the Company depends in part on its ability to find and develop or acquire additional reserves that are economically recoverable, which is dependent on oil and gas prices. Oil and gas exploration and production activities are capital intensive and inherently uncertain in their outcome. Significant expenditure is required to establish the extent of oil and gas reserves through seismic and other surveys and drilling and there can be no certainty that further commercial quantities of oil and gas will be discovered or acquired by the Company. The Company’s existing and future oil and gas appraisal and exploration projects may therefore involve unprofitable efforts, either from dry wells or from wells that are productive but do not produce sufficient net revenues to return a profit after development, operating and other costs. Moreover, geological formations and proximity with neighbouring fields may result in a regulatory requirement to unitize the license area with a neighbouring field. Such processes may prove complex, and thereby cause delays and uncertainties in respect of the Company's ultimate interest in the unitized field.

Few prospects that are explored are ultimately developed into producing oil and gas fields. Even if the Company is able to discover or acquire commercial quantities of oil and gas in the future, there can be no assurance that these will be commercially developed.

Completion of a well does not guarantee a profit on the investment or recovery of the costs associated with that well. Additionally, the cost of operations and production from successful wells may be materially adversely affected by unusual or unexpected geological formation pressures, oceanographic conditions, hazardous weather conditions, delays in obtaining governmental approvals or consents, shut-ins of connected wells, difficulties arising from environmental or other challenges or other factors. Any inability on the Company’s part to recover its costs and generate profits from its exploration and production activities could have a material adverse effect on its business, results of operations, cash flow and financial condition.

Additionally, several of the fields in which the Company has an interest have been producing for years. Producing oil and natural gas reservoirs, and particularly in the case of mature fields, are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than estimated and can change under other circumstances. Thus, the Company’s future oil and natural gas reserves and production and, therefore, its cash flow and results of operations are highly dependent upon the Company’s success in efficiently developing and exploiting its current properties and economically finding or acquiring additional recoverable reserves. The Company may not be able to develop, find or acquire additional reserves to replace its current and future production at acceptable costs. If the Company is unable to replace its current and future production, the value of its reserves will decrease, and its business, financial condition and results of operations would be adversely affected.

There are risks and uncertainties relating to extension of existing licenses and permits, including whether any extensions will be subject to onerous conditions

The Company's license interests for the exploration and exploitation of hydrocarbons will be subject to fixed terms, some of which will expire before the economic life of the asset is over. For example, the licences relating to the interest in five oil production concessions in Tunisia acquired in the OMV Transaction will expire the end of their economic life, and uncertainty surrounding the renewal of the Sfax permit which expired on 8 December 2018. Also, the Oil Mining Lease in Nigeria, OML 113, expired on 11 June 2018 but has, subject to certain conditions, been extended by 20 years on 13 August 2018. The Company plans to extend any permit or license where such extension is in the best interest of the Company. However, the process for obtaining such extensions is not certain and no assurances can be given that an extension in fact will be possible. In licenses where the Company is one of several license partners, such partners may also, against the wishes of the Company, resolve not to apply for any extensions.

Even if an extension is granted, such extension may only be given on conditions which are onerous or not acceptable to the Company and/or any license partners.

If any of the licenses expire, the Company may lose its investments into the license, charged penalties relating to unfulfilled work program obligations (such as at Sfax in Tunisia) and forego the opportunity to take part in any successful development of, and future production from, the relevant license area, which could have a material adverse effect on the Company's financial position and future prospects.

Local authorities may impose additional financial or work commitments beyond those currently contemplated

The Company'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 Company's financial position and future prospects could also be materially weakened.

The Company'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, drilling operation to be carried out and governmental approvals 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 Company'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 Company of its obligations and/or require the Company 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 Company, may have a material adverse effect on its business, results of operations, cash flow, financial condition and prospects.

The Company's current production and expected future production is concentrated in a limited number of hydrocarbon fields

Currently, all of the Company's production comes from two fields, Aje in Nigeria and Tortue in Gabon, with the latter reaching first oil in September 2018. The OMV Transaction includes producing assets in Tunisia.

Under any circumstance, the Company'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 Company, or new fields coming into production, it may have direct and significant impact on a substantial portion of the Company's production and hence the Company's revenue, profits and financial position as a whole.

Further, if the actual reserves associated with any one of the Company's fields are less than anticipated, this may result in material adverse effects for the Company, including on the Company's ability to make new investments and raise financing.

The Company's hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors

The Company's hydrocarbon production may be restricted, delayed or terminated due to a number of internal or external factors, among which are malfunctions of hydrocarbon discharge or production facilities, administrative delays (particularly in the approval of development projects by public authorities), shortages or delays in the availability of drilling and/or production rigs and delivery of equipment and materials, pressure or irregularities in geological formations, equipment failures or accidents or adverse weather conditions or malicious actions. The Company is especially sensitive to any shutdown or other technical issues on the Aje and/or Dussafu FPSOs. Any shutdown, technical issues, delay or other negative events in relation to the Aje FPSO and or the Dussafu FPSO may result in material adverse effects for the Group.

These factors may have a material adverse effect on the Company's cash flow as well as on its business, prospects, financial condition or results of operations.

The Company owns the Tunisian assets in a joint venture with a third party and conflict of interests may occur

Following completion of the Transaction, the Company owns its Tunisian assets together in a joint venture with a third party investor. The Company holds 60% of the joint venture, whereas the third party investor holds the remaining 40%.

As part of the establishment of the joint venture, the Company and the third party investor have entered into a shareholders' agreement, regulating, *inter alia*, the corporate governance structure of the joint venture. The shareholders' agreement gives the third party investor certain veto rights with respect to decision making in the joint venture.

Conflict of interests may occur in the future between the Company and the third party investor. Such conflicts may concern future investments into the assets in Tunisia and how such investments are to be funded, whether or not assets should be sold or acquired and with respect to several operational and strategic matters involving the Tunisian business. If such conflict should occur, the shareholders' agreement may not provide a solution to such conflict and, as a result, the joint venture and hence the Company could lose out on investments or divestments which the Company deems attractive, decisions could be delayed or prevented and the Tunisian operations could suffer accordingly.

If such conflicts occur and remain unsolved, it may have a material adverse effect on the Company's cash flow as well as on its business, prospects, financial condition or results of operations

The Company faces risks related to decommissioning activities and related costs

Several of the Company's license interests concern fields which have been in operation for years and which, consequently, will have equipment which from time to time will have to be decommissioned. In addition, the Company plans and expects to take part in developments and investments on existing and new fields, which will increase the Company's future decommissioning liabilities.

There are significant uncertainties relating to the estimated liabilities, costs and time for decommissioning of the Company' current and future licenses. Such liabilities are derived from legislative and regulatory requirements and require the Company to make provisions for such liabilities.

It is, therefore, difficult to forecast accurately the costs that the Company will incur in satisfying decommissioning liabilities. No assurance can be given that the anticipated cost and timing of removal are correct and any deviation from current estimates or significant increase in decommissioning costs relating to the Company's previous, current or future licenses, may have a material adverse effect on the Company.

The Company's operations are dependent on compliance with obligations under licenses, joint operating agreements, unitization agreements and field development plans

All exploration and production licenses have incorporated detailed and mandatory work programs that are required to be fulfilled within a specific timespan. Failure to comply with the obligations under the licenses may lead to fines, penalties, restrictions, revocation of licenses and termination of related agreements. A failure to comply with payment obligations (cash calls) under joint operating agreements (and unitization agreements) for the Company's licenses, may lead to penal interest on the defaulted amount, loss of voting rights and information within the license and a right for the other licensees to acquire the Company's participant interest on terms that are unfavourable to the Company and disconnected from the value of the license interest. Further, if other joint venture partners default on their payment obligations (cash calls), the Company may have to increase its interest level in the relevant field, which in turn will result in a corresponding increase in the Company's exposure and investment obligations towards the relevant field. Such increased exposure and obligations may result in the Company not being fully funded to meet such increased exposure and obligations and consequently could result in breach by the Company of its obligations and/or require the Company to raise additional debt and/or equity.

The Company is subject to third-party risk in terms of operators and partners and conflicts within a license group

Where the Company is not the operator of fields in which it has an interest, it has limited control over the management of the assets and mismanagement by the operator or disagreements with the operator as to the most appropriate course of action may occur, which again may result in significant delays, losses or increased costs to the Company. There is a risk that partners with interests in the Company's licenses may not be able to fund or may elect not to participate in, or consent to, certain activities relating to those licenses. In these circumstances, it may not be possible for such activities to be undertaken by the Company alone or in conjunction with other participants. Inversely, decisions by the other partners to engage in certain activities, may also be contrary to the Company's desire not to commence such activities and may require the Company to incur its share of costs in relation thereto, or that the other partners may enforce decisions which will delay or affect the profitability of a project. This is especially an inherent risk in fields under development where the Company only holds a minority interest. Other participants in the Company's licenses may default on their funding obligations. In such circumstances, the Company may be required under the terms of the relevant operating agreement or otherwise to contribute all or part of such funding shortfall. The Company may not have the resources to meet these obligations. If any of the Company's partners become insolvent or otherwise unable to pay debts as they come due, the license interest awarded to them may be revoked by the relevant government authority who will then reallocate the license interest.

There can be no assurance that the Company will be able to continue operations pursuant to these reclaimed licenses or that any transition related to the reallocation of the license would not materially disrupt the Company's operations.

The Company is subject to risks relating to capacity constraints and cost inflation in the service sector and lack of availability of required services and equipment

The Company is highly reliant upon services, goods and equipment provided by contractors and other companies to carry out its operations (including current and planned exploration and development projects). There is a continuing risk for capacity constraints and cost inflation in the service sector. Any non-performance, delays or faulty deliveries by contractors, or any other failure to obtain necessary services, goods or equipment, at all or at a reasonable cost, may expose the Company to significant delays, cost increases or liability, which may again lead to material adverse effects for the Company. Further, the Company's contractors and other companies may potentially be adversely affected by market conditions. If the Company's contractors, their suppliers or other companies should be unable to respect their obligations (towards the Company or others), become insolvent or otherwise unable to pay debts as they come due, this could lead to material adverse effects for the Company.

In addition, contractors and other service providers may cause third party liability or other losses for the Company by their performance. The Company may be subject to liability claims due to the inherently hazardous nature of its business or for act and omissions of sub-contractors and other service providers, and may also be liable for the operations of its contractors towards governmental authorities, licence partners or other third parties. Any indemnities the Company may receive from such parties may be inadequate and/or difficult to enforce, which could have a material adverse effect on the Company's financial condition, business, prospects and results.

The Company may not have access to necessary infrastructure or capacity booking for the transportation of oil and gas, and all transportation involve risks

The Company is, and will in the future be, dependent on capacity (whether through pipelines, tankers or otherwise) to process, transport and sell its oil and gas production. The Company, or the license group in which the Company holds or will hold an interest, may need to rely on access to third-party infrastructure to be able to process and transport produced oil and gas. There can be no assurance that the Company will be able to get access to necessary infrastructure at an economically justifiable cost, or access necessary infrastructure at all. If access to third-party infrastructure and necessary capacity bookings are unavailable or unavailable at an economically justifiable cost, the Company's income relating to the sale of oil and gas may be reduced, which may have a material adverse effect on the Company and its financial position. Further, all modes of transportation of hydrocarbons involve inherent risks. Hydrocarbons are by their nature hazardous and the Company is exposed to risk arising from possible major accidents or incidents with potentially hazardous impact on the environment and people given the high volumes involved in such transportation. The materialisation of such risk may result in material adverse effects for the Company's business, results of operations, financial condition and/or prospects.

The Company is vulnerable to adverse market perception

The Company must display a high level of integrity and maintain the trust and confidence of investors, license partners, public authorities, employees and numerous counterparties. Any mismanagement, fraud, HSE incidents or failure to satisfy contracts, fiduciary or regulatory responsibilities, allegations of such activities, negative publicity, or the association of any of the above with the Company could materially adversely affect its reputation and the value of its brand, as well as its business, results of operations, cash flow and financial condition.

The Company's ability to sell or transfer license interests may be restricted by regulatory consent requirements, provisions in its joint operating agreements including pre-emption rights, if any, or applicable legislation

The Company's exit in relation to any particular oil and gas interest may be subject to the prior approval of its commercial partners pursuant to joint operating agreements, unitization agreements and approval from the relevant authorities, thus restricting the Company's ability to dispose of, sell or transfer a license interest and make funds available when needed.

Moreover, once the Company has an interest in an established oil and/or gas exploration, development and/or production operation in a particular location, it may be expensive and logistically burdensome to discontinue such an operation should economic, physical or other conditions deteriorate. This is due to, among other reasons, the significant capital investments required in connection with oil and gas exploration, development and production, as well as significant decommissioning costs. Such costs and logistical burdens are typically greater for development and production assets due to the more established nature of the assets.

Additionally, because the trading of oil and gas assets may be relatively illiquid, the Company's ability to discontinue or dispose of all or a partial interest in assets promptly may be restricted. In the event that the Company wishes to dispose of some or all of its license interests in the future, no assurance can be given that the Company would be able to sell or swap any such asset on terms acceptable to the Company, or at all. It is not possible to predict the length of time required to find such acquirers for assets or to conclude asset disposals particularly in times of political, economic or financial change or uncertainty.

In the event the Company, for whatever reason, is not able or willing to execute a timely transaction, this can have an effect on the Company's ability to carry out investments and/or development with respect to the license in question. All of the above may have a material adverse effect on the Company's financial position.

The Company may be subject to liability under environmental laws and regulations

All phases of oil and gas activities present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and national laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, and releases or emissions of various substances. The legislation also requires that wells and facility sites are operated, maintained and abandoned to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties in addition to loss of reputation. Any pollution may give rise to material liabilities and may require the Company to incur material costs to remedy such discharge. No assurance can be given that current or future environmental laws and regulations will not result in a curtailment or shut down of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company.

The Company's business and financial condition could be adversely affected if tax regulations for the petroleum industry are amended

There is no assurance that future political conditions will not result in the relevant governments adopting different policies for petroleum taxation. In the event there are changes to such tax regimes, it could lead to new investments being less attractive, increase costs for the Company and prevent the Company from further growth. In addition, taxing authorities could review and question the Company's historical tax returns leading to additional taxes and tax penalties which could be material.

The Company faces the risk of litigation or other proceedings in relation to its business

The Company faces the risk of litigation and other proceedings in relation to its business. The outcome of any litigation may expose the Company to unexpected costs and losses, reputational and other non-financial consequences and diverting management attention away from operational matters, all of which could have a material adverse effect on the Company's business and financial position.

The Company will have guarantee and indemnity obligations

The Company will in its ordinary course of business provide guarantees and indemnities to governmental agencies, joint venture partners or third party contractors in respect of activities relating to its subsidiaries, inter alia for such subsidiaries working and abandonment obligations under licences or obligations under the relevant terms of agreements with third party contractors.

Should any guarantees or indemnities given by the Company be called upon, this may have a material adverse effect on the Company's financial position.

The Company is exposed to political and regulatory risks, including risks and uncertainties relating to regional (area) electrification

The oil and gas industry is subject to extensive government policies, standards, regulations and requirements. No assurance can be given that future political conditions, existing legislation, new interpretation of existing legislation or changes in administrative practice or policies, will not result in a reduction of income, curtailment of production, delays or a material increase in operating costs and capital expenditure or otherwise adversely affect the Company. In particular, the Company is exposed to risks relating to any future requirements for electrification of fields in development, which will include uncertainties related to the actual cost of electrification, allocation of such costs between the partners in the fields and the proposed timeline for electrification compared to the planned timeline for development of such field.

A failure to comply with applicable legislation, regulations and conditions or orders issued by the regulatory authorities, may lead to fines, penalties, restrictions, withdrawal of licenses and termination of related agreements. Additionally, the Company is dependent on receipt of discretionary government approvals, decisions and permits to develop and produce its assets. Further, the Company may be unable to obtain, renew or extend required drilling rights, licenses (including production licenses), permits and other authorizations and these may also be suspended, terminated or revoked prior to their expiration. The relevant authorities may also stipulate conditions for any such extension or for not revoking any licenses or permits. Lack of governmental approvals or permits or delays in receiving such approval may delay the Company's operations, increase its costs and liabilities or affect the status of its contractual arrangements or its ability to meet its contractual obligations.

Maritime disasters, employee errors and other operational risks may adversely impact the Company's reputation, financial condition and results of operations

The Company's offshore operations, which *inter alia* includes the operating of two FPSO vessels, are subject to all the risks common in its industry, including inter alia encountering unexpected rock formations or pressures, seismic shifts, blowouts, pollution, explosions, fires and equipment damage or failure. The facilities on offshore fields will also be subject to the hazards inherent in marine operations, such as inter alia capsizing, sinking, grounding and damage from severe weather conditions. Also, even though the Company's employees are well supervised, trained and experienced, personnel and employee errors and mistakes may take place. If any of these events were to occur, they could, among other adverse effects, result in environmental damage, injury to persons, loss of life, a failure to produce oil and/or gas in commercial quantities, delays, shut-down of operations or other damage. These events can also put at risk some or all of the Company's licenses and could inter alia result in the Company incurring significant civil liability claims, significant fines as well as criminal sanctions. In the Company's capacity as licensee, it is inter alia subject to liability provisions under the applicable statutory and regulatory regimes of the jurisdictions where the Company operates.

Any of these circumstances could adversely affect the operation of the Company's licenses, and result in loss of revenues or increased costs and adversely affect the Company's profitability.

The Company must use substantial time, attention and resources with respect to integration of the businesses acquired in Tunisia

Following the previous acquisition of license interests in Tunisia from DNO, and following completion of the Transaction, the Company will have to spend considerable time, attention and resources on integrating new employees and implementing a substantial new business into the existing business of the Company. This may require management to spend less time on operational and strategic issues and will also incur costs for the Company. Also, a successful and timely integration is important for the future success of the Company.

The Company's insurance or indemnities may not adequately cover all risks, liabilities or expenses that could result from its operations

The Company's offshore oil and gas operations are subject to all the significant risks and hazards typically associated with such operations. The Company is not necessarily fully insured against all risks it may face. It has for example currently not taken out business interruption insurance. Furthermore, not all mentioned risks are insurable, or only insurable at a disproportionately high cost. The nature of the hazards and risks typical for the Company's industry is such that liabilities could materially exceed policy limits or not be insured at all, which may result in substantial financial liability or losses. Any uninsured losses or liabilities, or any losses and liabilities exceeding the insured limits, may have a material adverse effect on the Company.

The Company may experience conflicts of interest

Some of the directors, officers and principal shareholders of the Company are or may become engaged in other oil and gas interests (including interests relating to oil and gas services) on their own behalf and on behalf of other companies resulting in a conflict of interest or direct competition with the Company. Such conflicts, if any, will be subject to the procedures and remedies under Norwegian company law (or any similar, foreign laws), but this may not prevent adverse effects for the Company with regard to such conflicts. The Company's directors, officers and principal shareholders may not devote their time on a full-time basis to the affairs of the Company as a result of such conflicts. Certain members of the Company's board of directors and senior management own collectively, directly and indirectly, a significant part of the outstanding share capital of the Company, and will therefore have the possibility to influence the decision-making in the Company and thereby the Company.

The risk of losing key employees

The loss of key employees, or a large number of employees in general, could adversely affect the Company's ability to operate its business in a proper and efficient way. The Company believes that its success depends on the continued service of its employees, as well as its ability to hire additional employees, when and as needed. The unexpected loss of the services of any of the key employees, or the Company's failure to find suitable replacements for employees leaving within a reasonable period of time thereafter, could have a material adverse effect on the Company's ability to execute its business plan and therefore, on its financial condition and results of operations.

The Company is exposed to risks relating to unionized labour and general labour interruptions

Strikes, labour disruptions and other types of conflicts with employees including those of the Company's independent contractors or their unions may occur in relation to the Company's operations. Any such disruptions or delays in the Company's business activities may result in increased operational costs or decreased revenues from delayed or decreased (or zero) production and significant budget overruns.

Changes in foreign exchange rates may affect the Company's results of operations and financial position

The Company is exposed to market fluctuations in foreign exchange rates. The Company may from time to time enter into foreign currency exchange hedging arrangements to manage the risk of foreign currency exposure and may also be required to provide security for such derivative transactions. Such security if provided could make it difficult for the Company to service its debt.

2.2 RISKS RELATING TO JURISDICTIONS IN WHICH THE GROUP OPERATES

Security risks associated with operating in Nigeria

The Aje field is located offshore and thus in an area with less security risk compared to the swamp area. However, the security risk could result in harm to the Aje field's operations and thus impact the economical income from the Aje field. There are some risks inherent to oil production in Nigeria. Since December 2005, Nigeria has experienced pipeline vandalism, kidnappings and militant takeovers of oil facilities in the Niger Delta. MEND is the main group attacking oil infrastructure for political objectives, claiming to seek a redistribution of oil wealth and greater local control of the sector. Additionally, kidnappings of oil workers for ransom are taking place. Security concerns have led some oil services firms to pull out of the country and oil workers unions to threaten strikes over security issues. The instability in the Niger Delta has caused shut-in production and several companies to declare force majeure on oil shipments.

Despite undertaking various security measures and being situated offshore the Nigerian coast, the Aje field installations may become subject to terrorist acts and other acts of hostility like piracy. Such actions could adversely impact on the Group's overall business, financial condition and operations. The Aje license's facilities are subject to these substantial security risks and its financial condition and results of operations may materially suffer as a result. The recent escalation in civil unrest in Nigeria, including attacks on oil workers by MEND in 2013 and clashes between different religious groups and future terrorist attacks carried out by certain Islamist group, including Boko Haram, may also pose a threat to the operations of the Group and any intensification in the level of civil unrest may have a material adverse effect on the Group' business, prospects, financial condition or results of operations.

Legal risks associated with operating in certain jurisdictions

Jurisdictions in which the Company operates may 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 owner ship 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 Issuer'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.

Governments may intervene in the oil and gas industry in ways that are unfavourable to the Company's business and strategy

Generally, exploration and development activities in which the Company operates or may operate can require lengthy negotiations with the governmental authorities and third parties and may be subject to expropriation, nationalisation, renegotiation, change or nullification of existing licences, changes to contracts, changes to royalty rates and taxes, difficulties in enforcing contractual rights, adverse changes to laws (whether of general application or otherwise) or the interpretation thereof, foreign exchange restrictions, changing political conditions, local currency devaluation, currency controls and the interpretation, implementation, enforcement of any laws or governmental regulations that favour or require the awarding of contracts to local contractors or require contractors to employ citizens of, or purchase supplies from, that country. Any of these factors detailed above or similar factors could have a material adverse effect on the Company's business, prospects, financial condition or results of operations.

Security Issues and Fraud, Bribery and Corruption

The Company operates and conducts business in countries in emerging market economies, experiences a considerable level of criminal activity, fraud, bribery and corruption. Oil and gas companies operating in Africa may be particular targets of criminal or militant actions.

Criminal, corrupt or militant action against the Company, its properties or facilities could have a material adverse effect on the Company's business, prospects, financial condition or results of operations. It may not be possible for the Company to detect or prevent every instance of fraud, bribery or corruption. Failure to detect or prevent any such instances may expose the Company to potential civil or criminal penalties under relevant applicable law and to reputational damage, which may have a material adverse effect on the Company's business, prospects, financial condition or results of operations.

2.3 RISKS RELATING TO THE OIL AND GAS INDUSTRY IN WHICH THE COMPANY OPERATES

The market in which the Company operates is highly competitive

The Company competes with a substantial number of other companies with larger technical staffs and greater resources, inter alia in acquiring (prospective) oil and gas licenses and attempting to secure drilling rigs and other equipment or services necessary for operation or projects. As a result of this competitive environment, the Company may inter alia be unable to acquire suitable licenses or licenses on terms that it considers acceptable, or equipment or services it requires may be in short supply. As a result, the Company's revenues may decline over time.

The oil and gas industry is characterized by rapid and significant technological advancements, and the Company may not be able to keep pace

As others use or develop new technologies, the Company may be placed at a competitive disadvantage over time or may be forced by competitive pressures to implement those new technologies at substantial costs. The Company may not be able to respond to these competitive pressures or implement new technologies on a timely basis or at an acceptable cost. Further, one or more of the technologies used by the Company now or in the future may become obsolete. In addition, new technology implemented by the Company may have unanticipated or unforeseen adverse consequences, either to its business or the industry as a whole.

Climate change abatement legislation, protests against fossil fuel extraction and regulatory, technological and market improvements within the renewable energy sector may have a material adverse effect on the oil and gas industry

Continued political attention to issues concerning climate change, the role of human activity in it and potential mitigation through regulation could have a material impact on the Company's business. International agreements, national and regional legislation, and regulatory measures to limit greenhouse emissions are currently in various stages of discussion or implementation. Given the Company'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 Company'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 Company's cost structure or causing disruption to its operations by regulators. In addition, the Company 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 Company's business.

The Company is affected by the general global economic and financial market situation

The Company may be materially and adversely affected by, amongst other things, the general state of the economy and business conditions, the occurrence of recession, inflation, adverse credit markets, fluctuations in operating expenses, technical problems, work stoppages or other labour difficulties. Weak global or regional economic conditions may negatively impact the business of the Company in ways that it cannot predict. Global financial markets and economic conditions have been severely disrupted and volatile in recent years and remain subject to significant vulnerabilities, such as the rapid accumulation of public debt, continued deleveraging in the banking sector and a limited supply of credit. The Company may, *inter alia*, experience difficulties obtaining financing commitments or be unable to fully draw on the capacity under committed loans it arranges in the future if its lenders are unwilling to extend financing to it or unable to meet their funding obligations due to their own liquidity, capital or solvency issues. The Company cannot be certain that financing will be available on acceptable terms, or at all. If financing is not available when needed, or is available only on unfavourable terms, the Company may be unable to meet its future obligations as they come due. The Company's failure to obtain such funds could have a material adverse effect on its business, results of operations and financial condition, as well as its ability to service its indebtedness.

2.4 FINANCIAL RISKS

The Company is exposed to credit risk

The Company may be exposed to financial loss if counterparties to contracts fail to meet their obligations. If significant amounts are not paid this could have a material adverse impact on the Company.

Existing debt is restrictive on the Company and the Company may have difficulties servicing debt in the future

The Company have incurred and may in the future incur debt or other financial obligations which could have important consequences to its business and holders of the Shares, including, but not limited to:

- making it difficult to satisfy the Company's obligations with respect to the such indebtedness;

- increasing the Company's vulnerability to, and reducing its flexibility to respond to, general adverse economic and industry conditions;
- requiring the dedication of a substantial portion of the Company's cash flow from operations to the repayment of the principal of its indebtedness and interest on such indebtedness, thereby reducing the availability of such cash flow;
- limiting the Company's ability to obtain additional financing to fund working capital, capital investments, acquisitions, debt service requirements, business ventures, or other general corporate purposes;
- limiting the Company's flexibility in planning for, or reacting to, changes in its business and the competitive environment and the industry in which the Company does business; and
- adversely affecting the Company's competitive position if its debt burden is higher than that of its competitors.

The Company is subject to time sensitive restructuring provisions as part of its debt financing plans

The Company's debt financing will require the Company within a stated period of time to establish a subsidiary to be a new holding company for the Tunisian assets to remove the need for an Austrian entity, and it may cause a default under the financing if the Company cannot achieve this restructuring and/or grant the required security, within the stated time period.

The Company will require a significant amount of cash to service current and future debt and sustain its operations, and its ability to generate sufficient cash depends on many factors beyond its control

The Company's ability to make payments on, or repay or refinance, any debt and to fund working capital and capital investments, will depend on its future operating performance and ability to generate sufficient cash. This depends on the success of its business strategy and on general economic, financial, competitive, market, legislative, regulatory, technical and other factors as well as the risks discussed in these "Risk Factors", many of which are beyond the Company's control. The Company cannot assure that its business will generate sufficient cash flow from operations or that future debt and equity financings will be available to it in an amount sufficient to enable it to pay its debt, or to fund its other liquidity needs. The Company cannot give assurance that it will be able to refinance any debt on commercially reasonable terms or at all. Any failure by the Company to make payments on debt on a timely basis would likely result in a reduction of its credit rating, which could also harm its ability to incur additional indebtedness. There can be no assurance that any assets that the Company may elect to sell can be sold or that, if sold, the timing of such sale will be acceptable and the amount of proceeds realized will be sufficient to satisfy its debt service and other liquidity needs.

If the Company is unsuccessful in any of these efforts, it may not have sufficient cash to meet its obligations, which could cause an event of default under any debt arrangements and could result in the debt being accelerated, lending reserves and certain bank accounts being frozen, triggering of cross-default provisions, enforcement of security and the companies of the Company, including the Company, being forced into bankruptcy or liquidation, which could result in an investor losing its investment in the Shares in its entirety.

The Company's working capital needs are difficult to forecast and may be subject to significant and rapid increases which could result in additional financing requirements that the Company may not be able to obtain on satisfactory terms or at all

The Company is unable to predict with certainty its working capital needs going forward. This is primarily due to possible new acquisitions or divestments of current assets, large capital requirements for general operating expenses, exploration and development expenditures. As the future level of income is also difficult to predict with any certainty due to uncertainties concerning prices for oil and gas and actual production levels, forecasting capital requirements is difficult and subject to substantial uncertainty, which could adversely affect the Company's ability to obtain required funds on satisfactory terms, or at all.

2.5 RISKS RELATING TO THE SHARES

The Shares may not be a suitable investment for all investors

Each potential investor in the Shares must determine the suitability of that investment in light of its own circumstances. In particular, each potential investor should: (i) have sufficient knowledge and experience to make a meaningful evaluation of the Shares, the Company and its business; (ii) have access to and knowledge of the appropriate analytical tools to evaluate an investment in the Shares; (iii) have sufficient financial resources and liquidity to bear the risks associated with investment in the Shares; (iv) understand the behaviour of the relevant financial markets; and (v) be able to evaluate possible scenarios for economic interest rate and other factors that may affect its investment.

Investing in the Shares involves inherent risks

Investing in the Shares inherently involves the risk that the value of the Shares will decrease or be lost. Thus, any prospective investor must be able to suffer such economic risk, and to withstand a complete loss of an investment in Shares.

The Shares may be subject to purchase and transfer restrictions

While the Shares are freely transferable and may be pledged, any Shareholder may be subject to purchase or transfer restrictions with regard to the Shares, as applicable from time to time under local laws to which a Shareholder may be subject (due e.g. to its nationality, its residency, its registered address, its place(s) for doing business or similar), including, but not limited to, specific transfer restrictions applicable to Shareholders located in the United States. Each Shareholder must ensure compliance with applicable local laws and regulations at its own cost and expense.

The trading price of the Shares may be volatile

The Company's Share price have experienced, and may in future still experience, substantial volatility. The trading price of the Shares could fluctuate significantly in response to, inter alia, the financial situation of the Company, variations in operating results, response to quarterly and annual reports issued by the Company, changes in earnings estimates by analysts, adverse business developments, changing conditions in the oil and gas industry at large, changes in general market or economic outlook, interest rate changes, foreign exchange rate movements, changes in financial estimates by securities analysts, matters announced in respect of major customers or competitors or changes to the regulatory environment in which the Company operates or rumours and speculation in the market. The equity markets in general have experienced extreme volatility that has at times been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of the Company's shares.

Shareholders may face currency exchange risks or adverse tax consequences by investing in the Shares denominated in currencies other than their reference currency

The Shares will be denominated and any dividend will be payable in NOK, and the Shares will be listed on the Oslo Stock Exchange where the trading price is quoted in NOK. If a Shareholder is a non-NOK investor, an investment in the Shares will entail currency exchange related risks due to, among other factors, possible significant changes in the value of the NOK to other relevant currencies because of economic, political or other factors over which the Company has no control. Depreciation of the NOK against other relevant currencies could result in a loss to Shareholders when any payment from the Shares is translated into the currency by reference to which a Shareholder measure the return on its investments.

Government and monetary authorities may impose (as some have done in the past) exchange controls that could adversely affect an applicable exchange rate. As a result, investors may receive less interest or principal than expected, or no interest or principal at all.

There may be tax consequences for a Shareholder as a result of any foreign currency exchange gains or losses resulting from its investment in the Shares. A Shareholder should consult its tax advisor concerning the tax consequences to Shareholders of acquiring, holding and disposing of the Shares.

Legal investment considerations may restrict certain investments

The investment activities of certain investors are subject to legal investment laws and regulations, or review or regulation by certain authorities. Each potential investor should consult its legal advisers to determine whether and to what extent (i) the Shares are legal investments for it, (ii) the Shares can be used as collateral for various types of borrowing and (iii) other restrictions apply to its purchase or pledge of the Shares. Financial institutions should consult their legal advisors or the appropriate regulators to determine the appropriate treatment of the Shares under any applicable risk-based capital or similar rules.

Shareholders may risk being diluted

The Company may in the future see the need of additional equity investment in relation to financing capital intensive projects, or related to unanticipated expenses or liabilities. This may lead to a future need of additional issuance of shares in the Company. The Company cannot guarantee that the current shareholders ownership will not be diluted. For reasons relating to U.S. securities laws, and the laws in certain other jurisdictions, or other factors, U.S. investors, and investors in such other jurisdictions, may not be able to participate in a new issuance of shares or other securities and may face dilution as a result.

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 Company's financial condition, capital requirements, earnings and other factors deemed relevant by its Board and general meeting of shareholders.

Holders of the shares that are registered in a nominee account may not be able to exercise voting rights as readily as shareholders whose shares are registered in their own names with the VPS

Beneficial owners of the shares that are registered in a nominee account (e.g., through brokers, dealers or other third parties) may not be able to vote for such shares unless their ownership is re-registered in their names with the VPS prior to the Company's general meetings. The Company cannot guarantee that beneficial owners of the shares will receive the notice for a general meeting in time to instruct their nominees to either effect a re-registration of their shares or otherwise vote their shares in the manner desired by such beneficial owners.

Pre-emptive rights may not be available to U.S. holders

In accordance with Norwegian law, prior to issuance of any shares for consideration in cash, the Company must offer holders of then-outstanding shares pre-emptive rights to subscribe and pay for a sufficient number of shares to maintain their existing ownership percentages, unless these rights are waived at a general meeting of the shareholders. These pre-emptive rights are generally transferable during the subscription period for the related offering and may be quoted on the OSE.

U.S. holders of the shares, and possibly holders of shares in other jurisdictions as well, may not be able to receive trade or exercise pre-emptive rights for shares in the Company unless a registration statement under the Securities Act (or similar provisions in other jurisdictions) is effective with respect to such rights or an exemption from the registration requirements of the Securities Act is available. The Company is not currently subject to the reporting requirements of the U.S. Securities and Exchange Act of 1934 (the "U.S. Exchange Act"), or any other foreign jurisdiction reporting requirements, and currently has no intention to subject itself to such reporting. If U.S. holders of the shares, or possibly holder of shares in other jurisdictions, are not able to receive trade or exercise pre-emptive rights granted in respect of their shares in any issue of shares by the Company, then they may not receive the economic benefit of such rights. Any such rights may, at the sole discretion of the Company, be sold on behalf of such shareholders and such shareholders may receive any profits from such sale, but any profit will depend on the prevailing market prices for the pre-emptive rights. In addition, such shareholder's proportionate ownership interests in the Company will be diluted.

Investors in the United States may have difficulty enforcing any judgment obtained in the United States against the Company or its directors or executive officers outside of the United States

The Company is incorporated in Norway and most of the Company's directors and executive officers reside outside the United States. All or a substantial portion of the assets of these persons and the Company are located outside the United States. In addition, the Company's auditors are also organized outside the United States. As a result, it may be difficult or impossible to serve process against any of these persons in the United States, including for U.S. securities laws violations. Furthermore, as all or substantially all of the assets of these persons are located outside of the United States, it may not be possible to enforce judgments obtained in courts in the United States predicated upon civil liability provisions of the federal securities laws of the United States against these persons. Additionally, there is doubt as to the enforceability in Norway of civil liabilities based on the civil liability provisions of the securities laws of the United States.

The insolvency laws of Norway may not be as favourable to Shareholders as insolvency laws of other jurisdictions and may preclude the holders of the Shareholders from recovering payments due on the Shares

As the Company is incorporated under the laws of Norway, an insolvency proceeding relating to the Company, even if brought in another jurisdiction, would likely involve Norwegian insolvency laws. The procedural and substantive provisions of such laws may differ from comparable provisions of those of other jurisdictions in which investors are familiar. Investors should also note that the process of making a claim as creditor or Shareholder of the Company under Norwegian law may be complex and time-consuming, and could result in substantial reductions in payments to holders of the Shares. The return for Shareholders in a bankruptcy proceeding is highly uncertain and will depend on the ability of the bankruptcy estate to realize the values of any unsecured assets, including the value obtainable in the market in a distressed situation and statutory restrictions imposed on the bankruptcy estate. Any of the issues described above may lead to a significant or total loss on an investment in the Shares.

The Shares are governed by Norwegian law and there are risks of changes to such laws

The Shares are governed by Norwegian law in effect as at the date of this Prospectus. No assurance can be given as to the impact of any possible judicial decision or change to such laws or administrative practices after the date of this Prospectus.

3. RESPONSIBILITY FOR THE PROSPECTUS

THE BOARD OF DIRECTORS OF PANORO ENERGY

The Board of Directors of Panoro Energy (the "**Board of Directors**" or the "**Board**") accepts responsibility for the information contained in this Prospectus. The Board of Directors hereby declares that, having taken all reasonable care to ensure that such is the case, the information contained in this Prospectus is, to the best of our knowledge, in accordance with the facts and contains no omissions likely to affect its import.

14 December 2018

Julien Balkany
Chairman

Alexandra Herger
Board member

Torstein Sanness
Board member

Garrett Soden
Board member

Hilde Ådland
Board member

4. GENERAL INFORMATION

4.1 PRESENTATION OF FINANCIAL AND OTHER INFORMATION

4.1.1 Financial information

The Group's audited consolidated financial statements as of, and for the years ended, 31 December 2017, 2016 and 2015 have been prepared in accordance with the International Financial Reporting Standards, as adopted by the EU ("**IFRS**"). The Group's audited consolidated financial statements as of, and for the years ended, 31 December 2017, 2016 and 2015 are together referred to as the "**Audited Financial Statements"** and incorporated by reference to this Prospectus. The Group's unaudited interim consolidated financial statements as of, and for the nine month periods ended, 30 September 2018 and 30 September 2017 (the "**Interim Financial Statements**"), have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" ("**IAS 34**") and are incorporated by reference to this Prospectus. The Audited Financial Statements and Interim Financial Statements are together referred to as the "**Financial Statements**". The Audited Financial Statements have been audited by Ernst & Young AS, as set forth in their auditor's report included herein.

The Company presents the Financial Statements in US$ (presentation currency) rounded to the nearest thousands.

The Company's auditor, Ernst & Young AS regarded the Board of Directors' application of the going concern assumption as reasonable, but regarded the uncertainties surrounding this assumption as particularly important for a full understanding of users of the financial statements and drew attention to the disclosure of these uncertainties without qualifying the financial statements.

The following emphasis of matters were included in the independent auditor's reports, respectively to the 2015 and 2016 annual accounts:

2015: *According to Note 1 and information in the Board of Director's report the appropriateness of the going concern assumption is dependent on the Company's ability to fund the future development of its assets. This condition, along with other matters as set forth in Note 1 and the Board of Director's report, indicate the existence of a material uncertainty that may cast significant doubt about the company's ability to continue as a going concern. The financial statement has been prepared under the assumption of going concern and realization of asset and settlement of debt in normal operations. No provisions or write-downs have been made for any losses that may occur if this assumption is no longer present. Our opinion is not qualified in respect of this matter"*.

2016: *"We draw attention to Note 1, Note 2.2b and the Board of Director's Report which indicate that the Company may require funding for future capital investments in existing projects or working capital requirements due to timing uncertainties regarding the legal dispute on Aje. Our opinion is not modified in respect of this matter."*

The independent auditor's report for 2017 did not contain any emphasis of matter.

4.1.2 Non-IFRS financial measures

In this Prospectus, the Company presents certain non-IFRS financial measures and ratios:

- Net profit margin represents net profit / (loss) as a percentage of total revenue.
- EBIT represents operating income / (loss) ("**EBIT**").
- EBIT margin represents EBIT as a percentage of total operating revenue.
- EBITDA represents operating income before depreciation and write-downs ("**EBITDA**").
- EBITDA margin represents EBITDA as a percentage of total operating revenue.
- Capital expenditures represent the sum of purchases of fixed assets and intangible assets.
- Free cash flow represents EBITDA less total Capital Expenditures.
- Cash conversion rate represents EBITDA less total Capital Expenditures as a percentage of EBITDA.
- Net interest expenses represent the sum of net foreign exchange (loss)/gain, interest costs net of income / effect of re-measurement of bond liability, and other financial costs.
- Interest coverage ratio represents EBIT divided by the sum of other financial income, changes in fair value of financial current assets, interest expenses and other financial expense.

The non-IFRS financial measures presented herein are not recognised measurements of financial performance under IFRS, but are used by management to monitor and analyse the underlying performance of the Company's business and operations. Investors should not consider any such measures to be an alternative to profit and loss for the period, operating profit for the period or any other measures of performance under generally accepted accounting principles.

The Company believes that the non-IFRS measures presented herein are commonly used by investors in comparing performance between companies. Accordingly, Panoro discloses the non-IFRS financial measures presented herein to permit a more complete and comprehensive analysis of its operating performance relative to other companies across periods. Because companies calculate the non-IFRS financial measures presented herein differently, the non-IFRS financial measures presented herein may not be comparable to similarly defined terms or measures used by other companies.

4.1.3 Industry and market data

This Prospectus contains statistics, data, statements and other information relating to markets, market sizes, market shares, market positions and other industry data pertaining to the Group's business and the industries and markets in which it operates. Unless otherwise indicated, such information reflects the Group's estimates based on analysis of multiple sources, including data compiled by professional organisations, consultants and analysts and information otherwise obtained from other third party sources, such as annual and interim financial statements and other presentations published by listed companies operating within the same industry as the Group, as well as the Group's internal data and its own experience, or on a combination of the foregoing. Unless otherwise indicated in this Prospectus, the basis for any statements regarding the Group's competitive position is based on the Company's own assessment and knowledge of the market in which it operates.

The Company confirms that where information has been sourced from a third party, such information has been accurately reproduced and that as far as the Company is aware and is able to ascertain from information published by that third party, 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 Company does not intend, and does not assume any obligations to, update industry or market data set forth in this 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 Company 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 predictive 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.

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.

4.1.4 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 NOTICE REGARDING FORWARD LOOKING STATEMENTS

This Prospectus includes "forward-looking" statements, including, without limitation, projections and expectations regarding the Group's future financial position, business strategy, plans and objectives. When used in this document, the words "anticipate", "believe", "estimate", "expect", "seek to" and similar expressions, as they relate to the Group or its management, are intended to identify forward-looking statements. Such forward-looking statements involve known and unknown risks, uncertainties and other factors, which may cause the actual results, performance or achievements of the Group, or, as the case may be, the industry, to materially differ from any future results, performance or achievements expressed or implied by such forward-looking statements. Such forward-looking statements are based on numerous assumptions regarding the Group's present and future business strategies and the environment in which the Group will operate. Factors that could cause the Group's actual results, performance or achievements to materially differ from those in the forward-looking statements include but are not limited to:

- the competitive nature of the markets in which the Group operates,
- global and regional economic conditions,
- government regulations,
- changes in political events, and
- force majeure events.

Some important factors that could cause actual results to differ materially from those in the forward-looking statements are, in certain instances, included with such forward-looking statements and in the section entitled "Risk Factors" (Section 2) in this Prospectus.

These forward-looking statements speak only as of the date of this Prospectus. Panoro undertakes no obligation to publicly update or revise any forward looking statements, whether as a result of new information, future events or otherwise, other than as required by law or regulation

Given the aforementioned uncertainties, prospective investors are cautioned not to place undue reliance on any of these forward-looking statements.

5. THE PRIVATE PLACEMENT

5.1 THE PURPOSE OF THE PRIVATE PLACEMENT AND USE OF PROCEEDS

The net proceeds of the Private Placment is estimated to be NOK 234.9 million (approximately US$ 28 million). The Company, through its 60% jointly controlled company, has entered into an agreement with OMV Exploration and Production GmbH (the "**Seller**") to acquire 100% shares in OMV Tunisia Upstream GmbH (the "**Target**"). The acquisition is a strategically important move for the Company and is complementary to its presence already established in the country.

Net proceeds of US$ 18 million will be used to finance the Company's 60% equity share of the acquisition of OMV Tunisia Upstream GmbH (the "**OMV Transaction**"). Approximately US$ 8 million of the remaining net proceeds will be used for oil and gas development projects, particularly in Gabon and Tunisia and approximately US$ 2 million for general working capital. It is not possible to allocate specific amounts or specify timing for Gabon and Tunisia development projects as investment decisions are dictated by JV operators' investment decisions, plans, availability of equipment (e.g. rigs and long lead items) and budgets which have not yet been sanctioned or committed at joint venture level by Panoro.

5.2 THE PRIVATE PLACEMENT

5.2.1 Overview of the Private Placement

On 6 November 2018, the Company announced a possible private placement of NOK 250.8 million. Following a pre-sounding, Panoro Energy and the Managers invited certain institutional and professional investors to participate in a book-building process in the Private Placement. The book building process commenced on 6 November 2018 at 16:30 and closed on 7 November 2018 at 00:10 for the issuance of placement shares corresponding to gross proceeds of NOK 250.8 million. The price was set at NOK 16.10 per share and 15,580,000 shares has been issued, following approval by the Extraordinary General Meeting ("**EGM**") and registration of the Placement Shares with the Norwegian Register of Business Enterprises.

The Board allocated the Placement Shares to investors based on consultations with the Managers. The allocation principles, in accordance with normal practice for institutional placements, included criteria such as, but not limited to, current ownership in the Company, timeliness of the application, price leadership, relative order size, sector knowledge, perceived investor quality and investment horizon. The Board of Directors decided to set aside the Shareholders' preferential right to subscribe for Shares.

In a board meeting held on 5 November 2018, the Company's Board of Directors resolved to call for an extraordinary general meeting of the Company scheduled for 29 November 2018. The Board of Directors proposed to approve the issuance of the Placement Shares and thereby to set aside existing shareholders' pre-emptive rights for subscription of new shares. The Board believes that this was in the best interest of the Company and the shareholders as reducing transaction risk and the time period from the transaction until the Company receives funds is imperative inter alia in order to secure funding to complete the acquisition of the Target. The Board is of the opinion that the private placement has allowed the Company to raise capital more quickly and, at a lower discount compared to a rights issue. Also, the Board is of the view that, in the current market situation and based on feedback from possible investors, a private placement had a greater chance of success than a rights issue. Further, in order to give shareholders who did not participate in the Private Placement the possibility to subscribe Shares at the same price as applicable to the Private Placement, the Board proposed to carry out a subsequent share issue.

At the EGM, the issuance of the Placement Shares was approved.

The EGM passed the following resolution to increase the Company's share capital in relation to the Private Placement:

1. *The Company's share capital is increased by NOK 779,000, from NOK 2,340,380 to NOK 3,119,380 by issue of 15,580,000 new shares, each having a face value of NOK 0.05.*

2. *Existing shareholders' preferential right to subscribe the shares is set aside.*

3. *The shares shall be subscribed no later than 15 December 2018 on a separate subscription form by SpareBank 1 Markets AS or Pareto Securities AS on behalf of, and pursuant to proxies from, the investors having ordered and been allocated shares in accordance with the Company's decision to allocate the shares.*
4. *The shares are subscribed at a price of NOK 16.10 per share.*
5. *The subscription amount is to be paid to the Company's account 9380.06.87118, IBAN: NO94 9380 0687 118, Swift: DNBANOKK no later than 15 December 2018.*
6. *The shares entitle to dividends as from the time of registration with the Register of Business Enterprises.*
7. *Assumed costs for the placement is approximately USD 1,900,000, which primarily relates to advisers' fees.*

The percentage of immediate dilution resulting from the Private Placement for Panoro Energy's shareholders is approximately 24.97%[1].

5.2.2 Issuance and Listing of the Placement Shares

The Placement Shares issued pursuant to the resolution by the EGM was issued and registered with the Norwegian Register of Business Enterprises and the VPS on 6 December 2018.

The Placement Shares were first registered on a separate ISIN (ISIN NO0010839012), and are expected to be registered with the Company's ordinary ISIN NO NO0010564701 following the approval of this Prospectus. The Placement Shares are subject to application for admission to trading on Oslo Stock Exchange. The Company expects the Placement Shares will be listed on Oslo Stock Exchange on or about 17 December 2018. The Placement Shares will not be sought admitted to trading on any other regulated market than Oslo Stock Exchange.

The Placement Shares carry full shareholder rights equal to the existing ordinary Shares of the Company. For a description of rights attaching to Shares in the Company, see section 12 of this Prospectus.

5.3 SUBSEQUENT OFFERING

5.3.1 Cancellation of subsequent offering

On 11 December 2018, the board of directors cancelled a contemplated subsequent offering due to Panoro shares trading below NOK 13 per share since 19 November 2019, compared to the subscription price of NOK 16.10 per share for the subsequent offering, meaning that interested investors may purchase Panoro shares in the market at a substantially lower price than the subscription price for the subsequent offering. For this reason, the board decided to cancel the subsequent offering as the prevailing market conditions so dictate, in line with authorisation given by the shareholders at the EGM.

5.4 VPS REGISTRATION

The Company's Shares are duly issued under Norwegian law and subject to the provisions of the Norwegian Public Limited Companies Act. The Shares are registered with VPS, the Norwegian Central Securities Depository. The Company's VPS registrar is Nordea Bank AB (publ), filial i Norge, Registrars department, Essendrops gate 7, 0368 Oslo, Norway.

The Placement Shares have as from issue been placed on a separate ISIN NO 0010839012. Following publication of this Prospectus, the Placement Shares will be transferred to the Company's ordinary ISIN NO 0010564701 and will be listed on Oslo Børs under the ticker code PEN.

[1] Calculated as the number of shares issued divided by the new total share count for the Company post completion of the Private Placement

5.5 SHARE CAPITAL FOLLOWING THE PRIVATE PLACEMENT

As of the date of this Prospectus, the Company's share capital is NOK 3,119,380 divided into 62,387,600 shares, each with a nominal value of NOK 0.05, including shares issued under the Private Placement. The Company's share capital is fully paid up and issued in accordance with Norwegian Law.

5.6 PROCEEDS AND COSTS

The transaction costs of the Company related to the Private Placement are estimated at approximately US$ 1.9 million, and accordingly the net proceeds of the Private Placement will be approximately US$ 28 million (or approximately NOK 234.9 million).

No expenses or taxes are charged to the subscribers in the Private Placement by the Company or the Managers.

5.7 DILUTION

The Company had 46,807,600 Shares outstanding prior to the Private Placement. A total of 15,580,000 new Shares was issued in the Private Placement, resulting in a dilution of approximately 24.97%[1] for existing shareholders who did not participate in the Private Placement.

5.8 MANAGERS AND ADVISORS

The Private Placement is being managed by Pareto Securities AS and SpareBank 1 Markets AS. Michelet & Co Advokatfirma AS is acting as Company's legal counsel in connection to the Private Placement.

5.9 JURISDICTION AND GOVERNING LAW

This Prospectus shall be governed by and construed in accordance with Norwegian law. Any dispute arising out of, or in connection with, this Prospectus shall be subject to the exclusive jurisdiction of Oslo District Court.

5.10 INTEREST OF NATURAL AND LEGAL PERSONS IN THE PRIVATE PLACEMENT

Pareto Securities AS and SpareBank 1 Markets AS serve as Managers in connection with the Private Placement and receives a success based fee and commission in this regard. The fee is a fixed percentage fee, calculated on the basis of the gross proceeds raised in the Private Placement.

The Manager and its affiliates are currently providing, and may provide in the future, investment and commercial banking services to the Company and its affiliates in the ordinary course of business, for which they may receive and may continue to receive customary fees and commissions. The Managers, its employees and any affiliate may currently own Shares in the Company.

Beyond the abovementioned, the Company is not aware of any interest of any natural or legal persons nor conflicts of interest involved in the Private Placement.

5.11 SUBSCRIPTIONS IN THE PRIVATE PLACEMENT BY MAJOR SHAREHOLDERS, MANAGEMENT, SUPERVISORY, ADMINISTRATIVE BODIES AND PERSON/ENTITIES SUBSCRIBING FOR MORE THAN FIVE PER CENT OF THE OFFERINGS

The table below provides an overview of members of management, supervisory and administrative bodies that participated in the Private Placement and other persons/entities that subscribed for more than five per cent of the Private Placement:

Investor	Shares subscribed	Share of offering

[1] Defined as total of new Shares issued in the Private Placement divided by the total number of Shares following the Private Placement.

Kistefos AS	4,968,944	31.89%
Sundt AS	1,614,906	10.37%
Julien Balkany or investment funds controlled by him (Chairman of the Board)	434,782	2.79%
Torstein Sanness (Director)	62,111	0.40%
John Hamilton (CEO)	6,211	0.04%
Qazi Qadeer (CFO)	6,211	0.04%
Richard Morton (Technical Director)	6,211	0.04%
Hilde Adland (Director)	3,105	0.02%

5.12 DISPARITY BETWEEN SUBSCRIPTION PRICE AND CASH COST FOR SUBSCRIPTIONS MADE BY MANAGEMENT

During the last 12 months prior to the date of this Prospectus, members of management have subscribed for Shares at a subscription price which materially deviates from the Subscription Price. The reason for this is that such members of management have been granted Restricted Share Units ("**RSUs**") as part of the Company's shareholder approved incentive program. Subject to certain conditions, each RSU gives the holder the right to subscribe for Shares against payment of the par value (NOK 0.05) of the Shares. The table below shows number of Shares subscribed by members of management pursuant to the RSUs for the last 12 months. No member of the Company's board have subscribed for shares at a subscription price which differs from the Subscription Price or the price applicable to the private placement announced in June 2018.

Name	Number of Shares subscribed last 12 months pursuant to RSU program	Subscription price per Share
John Hamilton	53,000	NOK 0.05
Qazi Qadeer	26,501	NOK 0.05
Richard Morton	21,200	NOK 0.05

6. CONSOLIDATED FINANCIAL INFORMATION

6.1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Group's audited consolidated financial statements as of, and for the years ended, 31 December 2017, 2016 and 2015 have been prepared in accordance with the International Financial Reporting Standards, as adopted by the EU. The Group's audited consolidated financial statements as of, and for the years ended, 31 December 2017, 2016 and 2015 are together referred to as the "**Audited Financial Statements"** and are incorporated by reference to this Prospectus. The Group's unaudited interim consolidated financial statements as of, and for the nine month periods ended, 30 September 2018 and 2017 (the "**Interim Financial Statements**"), have been prepared in accordance with International Accounting Standard 34 "Interim Financial Reporting" ("**IAS 34**") are incorporated by reference to this Prospectus. The Audited Financial Statements and Interim Financial Statements are together referred to as the "**Financial Statements**".

The Company presents the Financial Statements in US$ (presentation currency) rounded to the nearest thousands.

The selected financial data set forth below may not contain all of the information that is important to a potential investor of shares in the Company. As a result, the data should be read in conjunction with the relevant financial statements and the notes to those statements.

6.2 FUNDING AND TREASURY POLICIES AND BASIS FOR PREPARATION

The following tables present the data extracted from the audited historical financial statements of the Company's annual reports as of and for each of the three years ended 31 December 2017, 2016 and 2015. The interim financial information for the financial quarters ended 30 September 2018 and 2017 have been extracted from Panoro Energy's unaudited Interim Financial Statements published in the Company's 2018 and 2017 third quarter reports.

For information regarding accounting policies and the use of estimates and judgements, please refer to note 2 of the Audited Financial Statements, incorporated by reference in this Prospectus.

For the period covered by the Financial Statements, the Company operates predominantly in one business segment being the exploration of oil and gas in Africa. After the Company took a decision to cease all operations in Brazil, the segment has been classified as a discontinued operation. Brazilian items have been reported as discontinued operations in the financial years 2015, 2016 and 2017.

6.3 CONDENSED CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

		3 months ended		**9 months ended**			**12 months ended**
		30 September		**30 September**			**31 December**
US$ 000	**2018**	**2017**	**2018**	**2017**	**2017**	**2016**	**2015**
	Unaudited	*Unaudited*	*Unaudited*	*Unaudited*	*Audited*	*Audited*	*Audited*
CONTINUING OPERATIONS							
Revenue							
Oil and Gas revenue	2,642	3,117	7,267	4,444	6,021	5,461	-
Other income	-	-	-	497	497	-	-
Total revenue	2,642	3,117	7,267	4,941	6,518	5,461	-
Expenses							
Operating costs	(2,104)	(1,933)	(5,176)	(4,634)	(6,858)	(4,558)	-
Exploration related costs	(457)	(16)	(531)	(325)	(343)	(660)	(1,877)
Non-recurring dispute costs	(539)	(330)	(634)	(950)	(995)	-	-

	3 months ended		9 months ended		12 months ended		
	30 September		30 September		31 December		
US$ 000	**2018**	**2017**	**2018**	**2017**	**2017**	**2016**	**2015**
	Unaudited	*Unaudited*	*Unaudited*	*Unaudited*	*Audited*	*Audited*	*Audited*
General and administrative costs	(1,509)	(897)	(3,573)	(2,826)	(3,655)	(4,063)	(4,823)
Severance and restructuring costs	-	-	-	-	-	-	(38)
Depreciation	(822)	(404)	(2,309)	(2,010)	(1,898)	(2,231)	(90)
Impairment of assets	-	-	-	(25,970)	(28,576)	(55,795)	(32,445)
Share based payments	(66)	(60)	(163)	(97)	(149)	(47)	-
Total operating expenses	**(5,497)**	**(3,640)**	**(12,386)**	**(36,812)**	**(42,474)**	**(67,354)**	**(39,273)**
Operating loss	(2,855)	(523)	(5,119)	(31,871)	(35,956)	(61,893)	(39,273)
Net foreign exchange (loss)/gain	19	(2)	8	11	30	(33)	(25)
Interest costs net of income	(96)	12	(263)	18	(254)	43	73
Other financial costs	(38)	(34)	(108)	(103)	(136)	(104)	(14)
Loss before income taxes	**(2,970)**	**(547)**	**(5,482)**	**(31,945)**	**(36,316)**	**(61,987)**	**(39,239)**
Income tax benefit / (expense)				18	4	-	(46)
Net loss from continuing operations	**(2,970)**	**(547)**	**(5,482)**	**(31,927)**	**(36,312)**	**(61,987)**	**(39,285)**
DISCONTINUED OPERATIONS							
Net income / (loss) from discontinued operations	(27)	(29)	(116)	(217)	(277)	(649)	(582)
Net loss for the period	**(2,997)**	**(576)**	**(5,598)**	**(32,144)**	**(36,589)**	**(62,636)**	**(39,867)**
Exchange differences arising from translation of foreign operations	-	(1)	(3)	(3)	(3)	(10)	(19)
Other comprehensive loss for the period (net of tax)	**-**	**(1)**	**(3)**	**(3)**	**(3)**	**(10)**	**(19)**
Total comprehensive loss	**(2,997)**	**(577)**	**(5,601)**	**(32,147)**	**(36,592)**	**(62,646)**	**(39,886)**
Net loss attributable to:							
Equity holders of the parent	(2,997)	(576)	(5,598)	(32,144)	(36,589)	(62,636)	(39,867)
Total comprehensive loss attributable to:							
Equity holders of the parent	(2,997)	(577)	(5,601)	(32,147)	(36,592)	(62,646)	(39,886)
Earnings per share							
(US$) – Basic and diluted - Income/(loss) for the period attributable to equity holders of the parent - Total	(0.07)	(0.01)	(0.13)	(0.76)	(0.86)	(1.61)	(0.17)
(US$) – Basic and diluted - Income/(loss) for the period attributable to equity holders of the parent – Continuing operations	(0.07)	(0.01)	(0.13)	(0.75)	(0.85)	(1.60)	(0.17)

6.4 CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

US$ 000	As at 30 September 2018	As at 31 December 2017	2016	2015
	(Unaudited)	*(Audited)*	*(Audited)*	*(Audited)*
ASSETS				
Non-current assets				
Intangible assets				
Licenses and exploration assets	13,596	13,596	25,971	31,033
Total intangible assets	**13,596**	**13,596**	**25,971**	**31,033**
Tangible assets				
Production assets and equipment	23,407	9,902	25,285	-
Development assets	-	1,694	-	70,195
Property, furniture, fixtures and equipment	241	102	169	266
Other non-recurrent assets	129	134	122	962
Total tangible assets	**23,777**	**11,832**	**25,576**	**71,423**
Total non-current assets	**37,373**	**25,428**	**51,547**	**102,455**
Current assets				
Crude oil inventory	1,736	1,398	163	-
Materials inventory	1,470			
Trade and other receivables	1,574	615	1,724	1,693
Cash and cash equivalents	19,441	6,317	4,768	10,948
Restricted cash	127	1,500	520	-
Total current assets	**24,348**	**9,830**	**7,175**	**12,641**
TOTAL ASSETS	**61,721**	**35,258**	**58,722**	**115,096**
EQUITY AND LIABILITIES				
Equity				
Share capital	331	299	305	193
Share premium	304,925	297,490	297,503	288,858
Treasury shares	-	(503)	-	-
Additional paid-in capital	122,019	122,205	122,101	122,054
Total paid-in equity	**427,275**	**419,491**	**419,909**	**411,105**
Other reserves	(43,407)	(43,405)	(43,404)	(43,394)
Retained earnings	(364,364)	(358,766)	(322,177)	(259,540)
Total equity attributable to shareholder of the parent	**19,504**	**17,320**	**54,328**	**108,171**
Non-current liabilities				
Decommissioning liability	3,637	2,039	1,925	1,856
Long-term non-recourse loan	7,600	2,197	-	-
Long-term licence obligations	7,956	-	-	-
Deferred tax liability	-	-	-	4,376
Other non-current liabilities	6,847	6,892	88	-
Total non-current liabilities	**26,040**	**11,128**	**2,013**	**6,232**
Current liabilities				
Accounts payable and accrued liabilities	7,816	6,737	2,287	692

US$ 000	As at 30 September 2018	As at 31 December 2017	2016	2015
	(Unaudited)	*(Audited)*	*(Audited)*	*(Audited)*
Short-term non-recourse loan	5,306	-	-	-
Other short-term liabilities	3,000			
Corporation tax liability	55	73	94	1
Total current liabilities	**16,177**	**6,810**	**2,381**	**693**
TOTAL EQUITY AND LIABILITIES	**61,721**	**35,258**	**58,722**	**115,096**

6.5 CONSOLIDATED STATEMENTS OF CASHFLOWS

US$ 000	3 months ended 30 September 2018	2017	9 months ended 30 September 2018	2017	12 months ended 31 December 2017	2016	2015
Cash flows from operating activities	*Unaudited*	*Unaudited*	*Unaudited*	*Unaudited*	*Audited*	*Audited*	*Audited*
Net (loss) / income for the year before tax – Continuing operations	(2,970)	(547)	(5,482)	(31,945)	(36,316)	(61,987)	(39,239)
Net (loss) / income for the year before tax – Discontinued operations	(27)	(10)	(116)	(161)	(203)	(514)	(582)
Net (loss) / income for the year before tax	**(2,997)**	**(557)**	**(5,598)**	**(32,106)**	**(36,519)**	**(62,501)**	**(39,821)**
Adjusted for:							
Depreciation	822	404	2,309	2,010	1,898	2,231	90
Exploration related costs	457	16	531	325	343	660	1,877
Impairment and asset wrote-off	-	-	-	25,970	28,576	56,566	32,823
Net finance costs	134	22	371	85	390	61	(59)
Share-based payments	66	60	163	97	149	47	-
Foreign exchange loss / (gain)	(19)	2	(8)	(11)	(30)	33	25
Increase / (decrease) in trade and other payables	1,591	(1,691)	1,042	3,831	4,084	1,657	(838)
(Increase) /decrease in trade and other receivables	(885)	36	(959)	177	463	(1,188)	(583)
(Increase) /decrease in inventories	(810)	387	(1,808)	(776)	(1,235)	(163)	-
Taxes paid	(9)	(21)	(45)	(40)	(71)	(41)	(46)
Net cash flows from operating activities	**(1,650)**	**(1,342)**	**(4,002)**	**(438)**	**(1,952)**	**(2,638)**	**(6,532)**
Cash flows from investing activities							
Proceeds from disposal of Assets	-	-	-	11,737	12,737	-	-
Net cash acquired at acquisitions	8,271	-	8,271	-	-	-	-
Investment in exploration, production and other assets	(6,302)	-	(14,024)	(7,685)	(7,685)	(12,617)	(22,549)
Movement in related non-current assets	5,183	-	12,905	-	-	813	(962)
Net cash flows from investing activities	**7,152**	**-**	**7,152**	**4,052**	**5,052**	**(11,804)**	**(23,511)**
Cash flows from financing activities							

US$ 000	3 months ended 30 September 2018	2017	9 months ended 30 September 2018	2017	12 months ended 31 December 2017	2016	2015
Net proceeds from Equity Private Placement and Treasury Shares	8,580	(509)	8,580	(509)	(509)	8,774	-
Net financial income (net of charges paid)	4	-	23	(63)	(65)	18	59
Movement in restricted cash balance	(127)	-	1,373	(980)	(980)	(520)	-
Net cash flows from financing activities	**8,457**	**(509)**	**9,976**	**(1,552)**	**(1,554)**	**8,272**	**59**
Effect of foreign currency translation adjustment on cash balances	1	4	(2)	3	3	(10)	(9)
Change in cash and cash equivalents during the period	**13,960**	**(1,847)**	**13,124**	**2,065**	**1,549**	**(6,180)**	**(29,993)**
Cash and cash equivalents at the beginning of the period	5,481	8,680	6,317	4,768	4,768	10,948	40,941
Cash and cash equivalents at the end of the period	**19,441**	**6,833**	**19,441**	**6,833**	**6,317**	**4,768**	**10,948**

6.6 CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

US$ 000	Issued capital	Share premium	Treasury Shares	Additional paid-in capital	Retained earnings	Other reserves	Currency translation reserve	Total
At 1 January 2015 - (Audited)	**56,333**	**288,858**	**-**	**65,914**	**(219,672)**	**(37,647)**	**(5,730)**	**148,056**
Net income (loss) - Continuing Operations	-	-	-	-	(39,285)	-	-	(39,285)
- Discontinued Operations	-	-	-	-	(582)	-	-	(582)
Other comprehensive income/(loss)	-	-	-	-	-	-	(18)	(18)
Total comprehensive income/(loss)	56,333	288,858	-	65,914	(259,539)	(37,647)	(5,748)	108,171
Reduction in registered share capital	(56,140)	-	-	56,140	-	-	-	-
At 31 December 2015 - (Audited)	193	288,858	-	122,054	(259,539)	(37,647)	(5,748)	108,171
Net income (loss) - Continuing Operations	-	-	-	-	(61,987)	-	-	(61,987)
- Discontinued Operations	-	-	-	-	(651)	-	-	(651)
Other comprehensive income/(loss)	-	-	-	-	-	-	(10)	(10)
Total comprehensive income/(loss)	193	288,858	-	122,054	(322,177)	(37,647)	(5,758)	45,523
Share Issue for cash	112	9,295	-	-	-	-	-	9,407
Transaction cost on Share Issue	-	(650)	-	-	-	-	-	(650)
Employee share options	-	-	-	47	-	-	-	47
At 31 December 2016 - (Audited)	305	297,503	-	122,101	(322,177)	(37,647)	(5,758)	54,327
Net income (loss) - Continuing Operations	-	-	-	-	(36,312)	-	-	(36,312)
- Discontinued Operations	-	-	-	-	(277)	-	-	(277)
Other comprehensive income/(loss)	-	-	-	-	-	-	-	-
Total comprehensive income/(loss)	305	297,503	-	122,101	(358,766)	(37,647)	(5,758)	17,738

US$ 000	Issued capital	Share premium	Treasury Shares	Additional paid-in capital	Retained earnings	Other reserves	Currency translation reserve	Total
Purchase of own shares	(6)	-	(503)	-	-	-	-	(509)
Transaction cost on share buy back	-	(13)	-	-	-	-	-	(13)
Employee share options	-	-	-	149	-	-	-	149
Employee share options charge / (benefit)	-	-	-	(45)	-	-	-	(45)
At 31 December 2017 - (Audited)	299	297,490	(503)	122,205	(358,766)	(37,647)	(5,758)	17,320
Net income (loss) - Continuing Operations					(5,482)			(5,482)
- Discontinued Operations					(116)			(116)
Other comprehensive income/(loss)							(2)	(2)
Total comprehensive income/(loss)	299	297,490	(503)	122,205	(364,364)	(37,647)	(5,760)	11,720
Sale of own shares	6	(503)	503					6
Share issue for cash	26	8,295						8,321
Transaction costs on share issue		(250)						(250)
Employee share options charge / (benefit)				165				165
Employee share options grant charge / (benefit)	-	(107)	-	(351)	-	-	-	(458)
At 30 September 2018 - (Unaudited)	**331**	**304,925**	**-**	**122,019**	**(364,364)**	**(37,647)**	**(5,760)**	**19,504**

6.7 TREND INFORMATION AND SIGNIFICANT CHANGES TO PANORO ENERGY'S FINANCIAL POSITIONS SINCE 31 DECEMBER 2017

In July 2018, the Company announced completion of acquisition of DNO Tunisia AS (now renamed to Panoro Tunisia Exploration AS, "**PTE**"), assuming unfulfilled work obligations and retaining US$ 8.6 million in cash after completion adjustments. A private placement and sale of treasury shares which launched simultaneously, raised gross proceeds of US$ 8.3 million which strengthened the Group's funding situation considerably. Further details are outlined in section 7.5.

In September 2018, the Company achieved first oil production started from the Tortue field and concluded the successful drilling and completion of the Ruche North East (DRNEM-1) appraisal well located within the Dussafu PSC, offshore Gabon.

Except for the significant developments described above and the OMV Transaction as described in section 7.7, there has been no significant change in the financial or trading position of the Group since 31 December 2017.

The Company has not experienced any changes or trends outside the ordinary course of business that are significant to the Company after 30 September 2018 and to the date of this Prospectus. The Company does not know of any trends, uncertainties, demands, commitments or events that are reasonably likely to have a material effect on the Company's prospects for the current financial year.

6.8 SEGMENT INFORMATION

6.8.1 Operating Segments of Panoro Energy

From 2014, the Group operated predominantly in one business segment being the exploration of oil and gas in West Africa. After the Company took a decision to cease all operations in Brazil, the segment has been classified as a discontinued operation. As such, the segment information for December 31, 2017 does not include Brazilian operations. However, for the purpose of comparative information, the Brazilian segment has been included.

On 30 July 2018, the Company has completed the acquisition of DNO Tunisia AS (renamed subsequently to Panoro Tunisia Exploration AS) from DNO ASA as described in section 6.7. Panoro Tunisia Exploration AS operates in Tunisia and is classified as a new exploration segment namely North Africa.

The Group's reportable segments, for both management and financial reporting purposes, are as follows:

The West African segment holds the following assets:

- The Dussafu licence representing the Group's 8.333% working interest in the Dussafu Marin exploration licence in Gabon.
- The OML 113-Aje represents the Group's 16.255% paying interest (12.1913% revenue interest) in the OML 113-Aje exploration licence in Nigeria.

The North African segment holds the following assets:

- The Sfax Offshore Exploration Permit (containing the Ras El Besh Concession) representing the Group's 87.5% participating interest as operator in the Sfax Offshore Exploration Permit and the Ras El Besh Concession in Tunisia.
- The Hammamet Offshore Exploration Permit representing the Group's 46% interest as non-operator. This permit is in the process of being relinquished.

The 'Corporate and others' category consists of head office and service company operations that are not directly attributable to the other segment.

Management monitors the operating results of business segments separately for the purpose of making decisions about resources to be allocated and of assessing performance. Segment performance is evaluated based on capital and general expenditure after disposal of subsidiary in Brazil.

Nine months ended 30 September 2018

US$ 000 (unaudited)	**West Africa**	**North Africa**	**Corporate**	**Total - Continuing operations**	**Brazil - Discontinued operations**	**Total**
Revenue (net)	7,267	-	-	7,267	-	7,267
EBITDA	(1,001)	(775)	(871)	(2,647)	-	(2,647)
Depreciation	(2,213)	(54)	(42)	(2,309)	-	(2,309)
Impairment	-	-	-	-	-	-
Profit / (loss) before tax	(3,625)	(822)	(1,035)	(5,482)	(116)	(5,598)
Net profit / (loss)	(3,625)	(822)	(1,035)	(5,482)	(116)	(5,598)
Segment assets	40,518	11,404	9,783	61,705	16	61,721
- Additions to licenses and exploration assets	6,302	-	-	6,302	-	6,302

Nine months ended 30 September 2017

US$ 000 (audited)	**West Africa**	**Corporate**	**Total - Continuing operations**	**Brazil - Discontinued operations**	**Total**
Revenue (net)	4,941	-	4,941	-	4,941
EBITDA	(2,213)	(1,581)	(3,794)	(41)	(3,835)
Depreciation	(1,958)	(52)	(2,010)	-	(2,010)
Impairment	(25,970)	-	(25,970)	-	(25,970)
Profit / (loss) before tax	(30,312)	(1,633)	(31,945)	(161)	(32,106)
Net profit / (loss)	(30,312)	(1,615)	(31,927)	(217)	(32,144)
Segment assets	24,235	7,012	31,247	140	31,387
- Additions to licenses and exploration assets	8,445	-	8,445	-	8,445

Year ended 31 December 2017

US$ 000 (audited)	**West Africa**	**Corporate**	**Total - Continuing operations**	**Brazil - Discontinued operations**	**Total**
Revenue (net)	1,824	-	1,824	-	1,824
EBITDA	(2,587)	(1,148)	(3,735)	(35)	(3,770)
Depreciation	(1,571)	(35)	(1,606)	-	(1,606)
Impairment	(25,970)	-	(25,970)	-	(25,970)
Profit / (loss) before tax	(34,945)	3,547	(31,398)	(188)	(31,586)
Net profit / (loss)	(34,945)	3,563	(31,382)	(188)	(31,570)
Segment assets	24,032	8,812	32,844	186	33,030
- Additions to licenses and exploration assets	8,445	-	8,445	-	8,445

Year ended 31 December 2016

US$ 000 (audited)	**West Africa**	**Corporate**	**Total - Continuing operations**	**Brazil - Discontinued operations**	**Total**
Revenue (net)	5,461	-	5,461	-	5,461
EBITDA	(49)	(3,771)	(3,820)	(103)	(3,923)
Depreciation	(2,134)	(97)	(2,231)	-	(2,231)
Impairment	(55,608)	-	(55,608)	(419)	(56,027)
Profit / (loss) before tax	(60,286)	(1,701)	(61,987)	(514)	(62,501)
Net profit / (loss)	(60,286)	(1,701)	(61,987)	(514)	(62,501)
Segment assets	52,698	5,901	58,599	123	58,722
- Additions to licenses and exploration assets	13,503	-	13,503	-	13,503

Year ended 31 December 2015

US$ 000 (audited)	**West Africa**	**Corporate**	**Total - Continuing operations**	**Brazil - Discontinued operations**	**Total**
Revenue (net)	-	-	-	-	-
EBITDA	(1,954)	(4,784)	(6,738)	(112)	(6,850)
Depreciation	-	(90)	(90)	-	(90)
Impairment	(32,445)	-	(32,445)	(493)	(32,938)
Profit / (loss) before tax	(36,714)	(2,525)	(39,239)	(582)	(39,821)
Net profit / (loss)	(36,714)	(2,571)	(39,285)	(582)	(39,867)
Segment assets	103,698	11,120	114,818	278	115,096
- Additions to licenses and exploration assets	25,168	-	25,168	-	25,168

6.9 SELECTED OTHER FINANCIAL INFORMATION

The non-IFRS financial measures presented in this Prospectus are not recognised measurements of financial performance or liquidity under IFRS, but are used by Management to monitor and analyse the underlying performance of the Company's business and operations. In particular, non-IFRS financial measures should not be viewed as substitutes for any income statement, cash flow or balance sheet items shown herein and in accordance with IFRS. See Section 4.1 ("**Presentation of financial and other information**").

In US$ 000, except for percentages and ratios	**9 months ended 30 September**		**12 months ended 31 December**		
	2018	**2017**	**2017**	**2016**	**2015**
Net profit	(5,601)	(32,147)	(36,592)	(62,646)	(39,886)
Net profit margin (%)[1]	-77.07%	-650.62%	-561.40%	-1147.15%	n.m.
EBIT	(5,119)	(31,871)	(35,956)	(61,893)	(39,273)
EBIT margin (%)[2]	-70.44%	-717.17%	-597.18%	-1133.36%	n.m.
EBITDA	(2,647)	(3,794)	(5,333)	(3,820)	(39,183)
EBITDA margin (%)[3]	-36.42%	-85.37%	-88.57%	-69.95%	n.m.
Free cash flow[4]	(16,901)	(43,719)	(9,688)	(10,938)	(39,183)
Cash conversion rate (%)[5]	638.50%	1152.32%	181.66%	286.33%	100.00%

In US$ 000, except for percentages and ratios	**9 months ended 30 September**				**12 months ended 31 December**
	2018	**2017**	**2017**	**2016**	**2015**
Net interest expenses$^{(6)}$	(363)	(74)	(360)	(94)	34
Interest coverage ratio (x)$^{(7)}$	n.m	n.m	n.m	n.m	n.m

1) Net profit margin represents Net profit divided by Total revenue

2) EBIT margin represents EBIT divided by Total revenue

3) EBITDA margin represents EBITDA divided by Total revenue

4) Free cash flow represents EBITDA less total capital expenditures

5) Cash conversion rate represents EBITDA less total capital expenditures as a percentage of EBITDA

6) Net interest expenses represent the sum of Net foreign exchange (loss)/gain, Interest costs net of income / effect of re-measurement of bond liability, and other financial costs

7) Interest coverage ratio represents EBIT divided by the sum of Other financial income, Changes in fair value of financial current assets, Interest expenses and Other financial expense

6.10 STATUTORY AUDITORS

The Company's auditor for the years ended 31 December 2015, 2016 and 2017 is Ernst & Young, Dronning Eufemias gate 6, P.O. Box 20, NO-0051 Oslo, Norway. Ernst & Young is a member of the Norwegian Institute of Public Accountants (Den Norske Revisorforening). Their address is Dronning Eufemias gate 6, Oslo Atrium, P.O. Box 20, NO-0051 Oslo, Norway. Ernst & Young AS has been the Company's auditor throughout the period covered by financial information included in this Prospectus.

Ernst & Young AS has not audited, reviewed or produced any report on any information provided in this Prospectus, except for the statement relating to the pro forma financials, please see section 7.8.

The financial figures for the financial years ended 31 December 2015, 2016 and 2017 are audited. The financial figures presented for the Group for the interim information for the nine months ended 30 September 2017 and 2018 are unaudited.

There have been no audit qualifications in connection with the 2015, 2016 and 2017 financial statements for Panoro Energy.

In the 2015 audit report, the Company's auditors Ernst & Young AS regarded the Board of Directors' application of the going concern assumption as reasonable, but considered the uncertainties surrounding the Company's ability to raise future funding as matter of emphasis for a full understanding of users of the financial statements. They draw attention to Board of Directors discussion of the uncertainty concerning the Company's funding situation that was present at the time of the audit report, without qualifying its report, with the following wording: *"According to Note 1 and information in the Board of Director's report the appropriateness of the going concern assumption is dependent on the Company's ability to fund the future development of its assets. This condition, along with other matters as set forth in Note 1 and the Board of Director's report, indicate the existence of a material uncertainty that may cast significant doubt about the company's ability to continue as a going concern. The financial statement has been prepared under the assumption of going concern and realization of asset and settlement of debt in normal operations. No provisions or write-downs have been made for any losses that may occur if this assumption is no longer present. Our opinion is not qualified in respect of this matter"*.

In the 2016 audit report, the Company's auditors Ernst & Young AS regarded the Board of Directors' application of the going concern assumption as reasonable, but regarded the Company's need for possible funding for future capital investment or working capital due to timing uncertainties surrounding the legal dispute on Aje. They draw attention to disclosures made in the annual report without qualifying their opinion in the audit report, with the following wording: *"We draw attention to Note 1, Note 2.2b and the Board of Director's Report which indicate that the*

Company may require funding for future capital investments in existing projects or working capital requirements due to timing uncertainties regarding the legal dispute on Aje. Our opinion is not modified in respect of this matter."

The independent auditor's report for 2017 did not contain any emphasis of matter.

7. OPERATING AND FINANCIAL REVIEW

Since the activity in Panoro Energy ASA is limited the discussion in the following section is focusing on the Group, i.e. including Panoro Energy ASA's consolidated subsidiaries. The financial statements of Panoro Energy is incorporated by reference, see section 15.2 "Documents Incorporated by Reference" in this Prospectus.

The following discussion of the financial condition and results of operations should be read in conjunction with the financial statements included in this Prospectus. The following discussion may contain forward-looking statements that are based on current assumptions and estimates by Panoro Energy's management regarding future events and circumstances. Panoro Energy's actual results could differ materially from those expressed or implied by the forward-looking statements as a result of many factors, including those described in Section 2 "Risk factors". The selected historical consolidated financial data for Panoro Energy discussed in this section is based on the financial information as presented in the annual reports of years ended 31 December 2015, 2016 and 2017 and unaudited interim consolidated financial statements of the Company for the nine months ended 30 September 2017 and 2018.

7.1 Management's discussions and analysis of financial conditions and results of operations

7.1.1 Three months ended 30 September 2018 vs 30 September 2017

Panoro Energy reported a loss of US$ 3 million for the three months to 30 September 2018, compared to a loss of US$ 0.6 million in the same period in 2017.

Oil and gas revenue in the three months to 30 September 2018 was US$ 2.6 million compared to US$ 3.2 million in the same period in 2017. Revenue is based on the Company's entitlement barrels and the difference in revenue is a result of lower sales of the Company's net entitlement during the third quarter of 2018.

Costs attributed to operations were US$ 2.1 million at Aje for the third quarter 2018. This compares to US$ 1.9 million in the same period of 2017.The increase is consistent with the level of activity in the respective quarters. Exploration related costs increased by US$ 0.4 million in 3Q 2018 and General and Administrative costs by US$ 0.6 million in 3Q 2018 mainly as a result of the acquisition of Panoro Tunisia Exploration AS, in comparison to the same period in 2017. Depreciation, depletion and amortisation increased by US$ 0.4 million mainly for the three months to 30 September 2018, again due to the acquisition of Panoro Tunisia Exploration AS and initial depreciation of Tortue oil field, offshore Gabon, following the commencement of production in September 2018. Non-recurring costs during the three months ended 30 September 2018 of US$ 0.5 million relate to transaction costs of the Panoro Tunisia Exploration AS acquisition and US$ 0.3 million in the same period 2017 related to the Aje dispute.

Panoro Energy reported a net loss of US$ 3.0 million from continuing operations for the third quarter, 2018, compared to a loss of US$ 0.5 million in the same quarter in 2017. The current quarter loss is higher due to lower volumes lifted on Aje, the higher non-recurring transaction costs and additional costs related to the acquisition of Panoro Tunisia Exploration AS.

Net loss for the period from discontinued operations in Brazil was US$ 27 thousand for the current quarter, compared to the same period in 2017 at US$ 29 thousand.

The total net loss was US$ 3.0 million, compared to a net loss of US$ 0.6 million in the previous year.

7.1.2 Nine months ended 30 September 2018 vs 30 September 2017

Panoro Energy reported a loss of US$ 5.5 million for the nine months to 30 September 2018, compared to a loss of US$ 31.9 million in the same period in 2017.

Oil and gas revenue in the nine months to 30 September 2018 was US$ 7.3 million and include the oil and gas revenue from the two liftings from the Aje field during 2018 and the associated Aje operating costs. Revenue is based on the Company's entitlement barrels; the revenue was generated by the sale of the net entitlement volume of 105,129 bbls. This compares to revenue of

US$ 4.4 million in the nine months to 30 September 2017 from the sale of the Company's net entitlement barrels of 87,389 bbls.

Panoro Energy reported a net loss of US$ 5.5 million from continuing operations for the nine months to 30 September 2018, a decrease in loss of US$ 26.5 million, compared to a loss of US$ 31.9 million in the same period in 2017. The decrease in loss was mainly due to the inclusion of Aje impairment charges in 2017.

Exploration related costs increased to US$ 0.5 million in the nine months to 30 September 2018, up from US$ 0.3 million in same period in 2017, with 2018 including the effect of exploration related costs of US$ 0.4 million which form part of the acquisition of DNO Tunisia AS.

General and Administration costs from continuing operations were US$ 3.6 million in the nine months to 30 September 2018, up from US$ 2.8 million for the same period in 2017, reflecting the inclusion of US$ 0.4 million for Tunisia and new business activities undertaken during 2018. Non-recurring transaction costs of US$ 634 thousand primarily relate to acquisition projects which has been expensed as incurred.

Depreciation for the period was US$ 2.3 million, increasing from US$ 2.0 million in the same period in 2017, predominantly relating to the depreciation of the Aje Cenomanian oil field in both periods. However, 2018 reflects the initial depreciation of Tortue oil field, following first oil in the third quarter, 2018 and also the inclusion of depreciation charges as part of the acquisition of DNO Tunisia AS.

The operating loss from continuing operations was thus a US$ 5.1 million for the nine months to 30 September 2018, compared to a loss of US$ 31.9 million in the same period of 2017. The change relates to the inclusion of impairment charges on Aje field in 2017.

Net financial items amounted to an expense of US$ 363 thousand in the current period compared to an expense of US$ 74 thousand in the same period in 2017. This is due to accretion of notional interest on the Aje Asset Decommissioning Liability and finance charges.

Loss before tax from continuing activities was US$ 5.5 million for the nine months to 30 September 2018, compared to the loss of US$ 31.9 million for the same period in 2017. The higher loss in 2017 is originating from impairment charges on Aje field.

Net loss for the period from discontinued operations in Brazil was US$ 116 thousand for the current period, compared to a net loss of US$ 217 thousand for the same period in 2017.

The total net loss for the nine months to 30 September 2018 was US$ 5.6 million, compared to a net loss of US$ 32.1 million for the same period in 2017.

Minor movement in respective periods to other comprehensive income was a result of currency translation adjustments for reporting purposes.

7.1.3 Year ended 31 December 2017 vs 31 December 2016

Panoro Energy reported a loss of US$ 36.3 million from continuing operations for the year ended 31 December 2017, compared to a loss of US$ 62.0 million in the same period in 2016. The decrease in loss was a direct result of the lower impairment charges in 2017.

Operating loss includes the oil and gas revenue from the four liftings from the Aje field during 2017 and the associated operating costs and the gain on the sale of a 25% stake in Dussafu.

Oil and gas revenue in the period was US$ 6.0 million and is based on the Company's entitlement barrels; the revenue was generated by the sale of the net entitlement volume of 113,367 bbls. Other Income in the same period of US$ 0.5 million represents the net gain on disposal of the 25% working interest in Dussafu. Oil & gas revenue in the same period of 2016 was US$ 5.5 million and was generated by the sale of the net entitlement volume of 110,539 bbls.

Operator G&A and related overheads decreased to US$ 0.3 million in the year ended 31 December 2017, down from US$ 0.7 million in same period in 2016.

General and Administration costs from continuing operations were US$ 3.7 million for year ended 31 December 2017, down from US$ 4.1 million for the same period in 2016. In 2017, US$ 1.0 million of costs directly related to the Aje dispute have been reported separately as non-recurring dispute costs; there were no such costs in the same period in 2016. This amount is net of an award of US$ 0.4 million reimbursement of costs pursuant to Court orders.

Depreciation for the period was US$ 1.9 million decreasing from US$ 2.2 million in the same period in 2016 with both periods relating to the depreciation of the Aje Cenomanian oil field. 2017 is a comparatively lower charge following an impairment exercise on Aje.

Operating loss from continuing operations was thus a negative US$ 36 million for the year ended 31 December 2017, compared to a negative US$ 61.9 million in the same period of 2016.

Net financial items amounted to an expense of US$ 360 thousand in the current period compared to an expense of US$ 94 thousand in the same period in 2016. This is due to accretion of notional interest on the Aje Asset Decommissioning Liability during 2017 and finance charges.

Net loss from continuing operations was US$ 36.3 million for the year ended 31 December 2017 compared to the loss of US$ 62.0 million for the same period in 2016. The decrease in loss in 2017 is predominantly due to the inclusion of impairment provision for Aje and Dussafu in 2016.

Net loss for the period from discontinued operations in Brazil was US$ 277 thousand for the period, compared to a net loss of US$ 649 thousand for the same period in 2016. The total net loss for the year ended 31 December 2017 was US$ 36.6 million, compared to a net loss of US$ 62.6 million for the same period in 2016.

7.1.4 Year ended 31 December 2016 vs 31 December 2015

Panoro Energy reported a net loss of US$ 62.0 million from continuing operations for the year ended 31 December 2016, compared to a loss of US$ 39.3 million in 2015. The increase in loss was significantly affected by the inclusion of impairment charges in 2016.

Operating loss includes the oil and gas revenue from the first two liftings from the Aje field and the associated operating costs. In addition to the inclusion of Aje's liftings, an overall decline in G&A and exploration related costs was also noted. Oil and gas revenue in the period was US$ 5.5 million and is based on the Company's entitlement barrels. The revenue was generated by the sale of the net entitlement volume of 110,539 bbls.

From commencement of commercial production, field operating costs per production barrel were US$ 27.30/bbl and US$ 30.42/bbl with royalties included. Through a carry arrangement, under the OML 113 Joint Operations Agreement (JOA), the Company's share of capital and operating expenditure is 16.255% (paying interest), whereas the allocation of revenue to the Company is at 12.1913% (revenue interest). Based on the net barrels produced which the Company is entitled to sell, Panoro's operating costs per barrel equated to US$ 36.40/bbl and US$ 40.55/bbl with royalties included. The revenue allocation of 12.1913% will increase to 16.255% once certain pre-defined financial thresholds are met under the JOA. Operating costs will continue to be reviewed aggressively at the JV level; on a normalised production range, the operating cost per barrel is expected to reduce in line with previous estimates.

Exploration related costs and operator G&A decreased to US$ 0.7 million in the year ended 31 December 2016, down from US$ 1.9 million in 2015. This is consistent with the majority of the Aje operator general and administrative costs since first oil being classified as operating costs during 2016.

General and Administration costs from continuing operations decreased to US$ 4.1 million for the year ended 31 December 2016 compared to US$ 4.8 million in the comparative period in 2015, culminating in a year-on-year decrease of 15.8%. The reduction is a result of continued cost saving efforts and by currency variations on GBP denominated costs.

Depreciation for the year ended 31 December 2016 was US$ 2.2 million increasing from US$ 90 thousand in the same period in 2015 as a direct result of the commencement of the depreciation of the Aje Cenomanian oil field in 2016.

During the year ending 31 December 2016, the Company recorded a provision for impairment totalling US$ 55.9 million against its investment in Aje asset in Nigeria (US$ 38.8 million) and Dussafu asset in Gabon (US$ 17.1 million). The Aje impairment is a result of application of accounting principles to determine the recoverable amount of the asset as of the balance sheet date. It has been considered following triggers and factors that include amongst others, the recent Aje well performance, rationalisation of historically high exploration costs and a reflection of risks associated with the asset in the current environment. In order to make such determinations, qualitative and quantitative factors were considered. The Dussafu impairment was the result of the effect of lower oil prices at the time and was considered to be a fair and current reflection on the Company's valuation of the carrying value of the asset. The recognition of such provision was in line with the relevant accounting guidance and does not represent an underlying change in technical view of either of the assets.

Operating loss from continuing operations was thus a negative US$ 61.9 million for the year ending 31 December 2016, compared to a negative US$ 39.3 million in 2015.

Net financial items amounted to an expense of US$ 94 thousand in the current period compared to an income of US$ 34 thousand in the same period in 2015. This is due to accretion of US$ 69 thousand notional interest on the Aje Asset Decommissioning Liability.

Loss before tax from continuing activities was US$ 62.0 million for the year ending 31 December 2016 compared to the loss of US$ 39.3 million for the same period in 2015. The increase in loss in 2016 is predominantly due to the inclusion of impairment provisions for both Dussafu and Aje.

Net loss for both periods from discontinued operations was US$ 0.6 million.

7.2 MANAGEMENT'S DISCUSSIONS OF FINANCIAL POSITION

7.2.1 30 September 2018 vs 31 December 2017

Movements in the Group statement of financial position during the nine months to 30 September 2018 were a combination of the following:

Non-current assets amounted to US$ 37.4 million at 30 September 2018, an increase of US$ 11.9 million from 31 December 2017.

The overall movement in total non-current assets relates to capital additions on Dussafu in the period of US$ 14.0 million, partially offset by the effect of the Aje depreciation charge of US$ 2.2 million. Property, furniture, fixtures and equipment reflects the inclusion of assets which form part of the acquisition of DNO Tunisia AS.

Other non-current assets remained unchanged at US$ 0.1 million for both periods and mainly relates to the tenancy deposit for office premises.

Current assets amounted to US$ 24.3 million as of 30 September 2018, compared to US$ 9.8 million at 31 December 2017.

During the nine months to 30 September 2018, the Company completed the acquisition (the "**Transaction**") of DNO Tunisia AS (now renamed to Panoro Tunisia Exploration AS "**PTE**"). The Company assumed the unfulfilled work obligations as part of the Transaction, also retaining approximately US$ 8.6 million in cash after completion adjustments.

Also during the period, An Equity Private Placement of 10% of Panoro's share capital and sale of treasury shares was launched simultaneously with the Transaction, which resulted in a significantly oversubscribed issue, raising gross proceeds of US$ 8.3 million net to Panoro.

In addition, trade and other receivables stood at US$ 1.6 million, an increase from US$ 0.6 million at the end of December 2017. US$ 1.7 million has been accumulated and held on the balance sheet as the cash cost of Aje crude oil inventory and materials inventory of US$ 1.5 million as part of the Transaction.

Consequently, cash and cash equivalents stood at US$ 19.4 million at 30 September 2018, compared to US$ 6.3 million at 31 December 2017.

Equity amounted to US$ 19.5 million as of 30 September 2018, compared to US$ 17.3 million at the end of December 2017. The change reflects completion of the Private Placement, the sale of the Company's treasury shares and also the loss for the period.

Non-current liabilities were US$ 26.0 million as at 30 September 2018, compared to US$ 11.1 million as at 31 December 2017.

The increase includes the non-recourse loan from BW Energy on Dussafu, which has now been split and reclassified into long-term (US$ 7.6 million) and short-term (US$ 5.3 million). As of 30 September 2018, Panoro's drawdown on the non-recourse loan was at the loan facility's ceiling of US$ 12.5 million, with additionally US$ 0.4 million of accumulated interest, compared to US$ 2.2 million as at 31 December 2017. The non-recourse loan became repayable through Panoro's allocation of the cost oil in accordance with the Dussafu PSC, after paying for the proportionate field operating expenses, following First Oil on Dussafu, achieved during the period. During the repayment phase, Panoro will still be entitled to its share of profit oil, as defined in the PSC, from the Dussafu operations.

In addition, Panoro has assumed the unfulfilled work obligations as part of the Transaction and as such, US$ 8.0 million is reflected in long-term licence obligations.

Decommissioning provisions for both the Aje and Dussafu fields have been recognised for US$ 3.6 million, following the oil production start-up at Dussafu, during the quarter.

Other non-current liabilities include US$ 6.8 million associated with historic cash calls on Aje, which will be settled from surplus funds, where available, from Aje crude sales after paying for current costs and JV liabilities.

Current liabilities amounted to US$ 16.2 million at 30 September 2018, compared to US$ 6.8 million at the end of December 2017.

US$ 5.3 million reflects the reclassification in part of the Dussafu non-recourse loan and US$ 3.0 million of the short-term portion of unfulfilled work obligations as part of the Transaction. Although there is an increase in accounts payable, accruals and other liabilities compared to 31 December 2017, there is an underlying reduction in current Aje operational payables of US$ 1.5 million. The tax liability of US$ 0.1 million remain unchanged and relates to recognised historical tax liability in Brazil.

In addition to these, US$ 6.8 million is classified as long-term liabilities which as per the terms agreed between OML 113 Joint Venture partners, certain transitional arrangements were introduced whereby unpaid cash calls will not be immediately payable. During the transition period, any excess funds from Panoro's entitlement of crude liftings after paying for its share of operating expenditure shall be used to repay unpaid cash calls. We do not anticipate any use of Panoro's cash resources and expect it to be funded from the sale of our share of Aje crude. An Aje lifting was scheduled for November, which will provide net proceeds to Panoro in the region of US$ 2.5 million; Panoro's share of these proceeds will reduce Aje related payables (which includes operating costs) in the fourth quarter 2018.

7.2.2 31 December 2017 vs 31 December 2016

Movements in the Group statement of financial position during 2017 were a combination of the following:

Non-current assets amounted to US$ 25.4 million at 31 December 2017, a decrease of US$ 26.1 million from 31 December 2016. The overall decline in total non-current assets was a result of the sale of 25% stake in Dussafu during the period and impairment provisions, offset by capital expenditure on both the assets.

Property, furniture, fixtures and equipment remained largely unchanged at US$ 0.1 million.

Other non-current assets remained unchanged at US$ 0.1 million for both periods and relates mainly to the tenancy deposit for office premises.

Current assets amounted to US$ 9.8 million as of December 31, 2017, compared to US$ 7.2 million at 31 December 2016.

Trade and other receivables stood at US$ 0.6 million, a decrease from US$ 1.7 million at the end of December 2016. The movement is due predominantly to the realisation of sale proceeds due for Aje's liftings during the period, offset by Panoro's portion of unspent cash held in Dussafu JV. US$ 1.4 million has been accumulated and held on the balance sheet as the cash cost of Aje crude oil inventory.

Cash and cash equivalents stood at US$ 6.3 million at 31 December 2017, not including US$ 1.5 million cash which was released back to the Company, with interest post-period-end, having been held as collateral against dispute costs by the UK Court Funds Office. This represents an increase from US$ 4.8 million cash and cash equivalents at 31 December 2016. The increase is mainly attributed to the collection of the sale proceeds relating to the disposal of 25% stake in Dussafu during the period and proceeds from the Aje liftings during the period. This has been offset by the payment of Aje cash calls of US$ 4.0 million and the repurchase of 1,000,000 Panoro shares for US$ 0.5 million. US$ 1.5 million of Aje dispute cash collateral remains as restricted cash during the period, although released back to Company post-period-end, increasing from US$ 0.5 million as at 31 December 2016.

Equity amounted to US$ 17.3 million as of 31 December 2017, compared to US$ 54.3 million at the end of December 2016. The change reflects the loss for the period and the effect of the repurchase of 1,000,000 Panoro shares in August 2017.

Total non-current liabilities of US$ 11.1 million for the year ended 31 December 2017, compared to US$ 2.0 million for the same period in 2016 including the decommissioning provision for the Aje field. There is also the inclusion of the non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of 31 December 2017, Panoro's drawdown on the non-recourse loan was US$ 2.2 million. The nonrecourse loan is repayable through Panoro's allocation of the cost oil in accordance with the Dussafu PSC, after paying for the proportionate field operating expenses. The repayment will start at First Oil on Dussafu. During the repayment phase, Panoro will still be entitled to its share of profit oil, as defined in the PSC, from the Dussafu operations.

Other non-current liabilities include US$ 6.8 million associated with historic cash calls on Aje, which will be settled from surplus funds, where available, from Aje crude sales after paying for current costs and liabilities.

Current liabilities amounted to US$ 6.8 million at 31 December 2017, compared to US$ 2.4 million at the end of December 2016.

Accounts payable, accruals and other liabilities amounted to US$ 6.7 million, an increase from US$ 2.3 million at the end of December 2016. The increase represents Aje operational accruals and higher corporate trade payables as at 31 December 2017. The tax liability of US$ 0.1 million is in relation to historical tax liability in Brazil.

Since the settlement of the Aje dispute, the Company has performed a review of historical costs incurred and recognised the liabilities associated with such expenditures in the balance sheet. The proportionate joint venture liabilities resulting from the workover and side-tracks at Aje-5 have been higher than anticipated and as such have resulted in proportional liabilities of US$ 6.1 million as of 31 December 2017. Such liabilities are current in nature and are expected to be repaid in full by the end of financial year 2018. In addition to these, US$ 6.8 million is classified as long-term liabilities which as per the terms agreed between OML 113 Joint Venture partners, certain transitional arrangements were introduced whereby unpaid cash calls will not be immediately payable. During the transition period, any excess funds from Panoro's entitlement of crude liftings after paying for its share of operating expenditure shall be used to repay unpaid cash calls. In addition to this, commercial arrangements agreed as part of the interim settlement measures are expected to have the effect of increasing Panoro's existing revenue interest for the remainder of 2018. It is anticipated that operating costs for OML 113 will be funded in entirety from the sale of our share of Aje crude during 2018.

7.2.3 31 December 2016 vs 31 December 2015

Movements in the Group statement of financial position during 2017 were a combination of the following:

Non-current assets amounted to US$ 51.5 million at December 31, 2016, a decrease of US$ 50.9 million from 31 December 2015. This can be analysed as: capital additions during the period were US$ 14.3 million, offset by US$ 60.3 million impairment charges US$ 1.0 million expensing of Aje pre-commencement costs and US$ 2.2 million depreciation charges.

Property, furniture, fixtures and equipment was US$ 169 thousand decreasing from US$ 266 thousand at 31 December 2015. The decrease represents the depreciation of office premises in 2016 information technology upgrades carried out in 2015.

Other non-current assets decreased to US$ 0.1 million as at 31 December 2016 as a result of the capitalisation of the Rubicon FPSO guarantee deposit of US$ 0.8 million. The remaining US$ 0.1 million relates to the tenancy deposit for office premises.

Current assets amounted to US$ 7.2 million per December 31, 2016, compared to US$ 12.6 million per 31 December 2015.

Trade and other receivables stood at US$ 1.7 million for both periods. This reflects the utilisation of the cash calls paid during the year, resulting in a similar receivable balance of prepaid cash calls at the end of both periods. In addition, US$ 0.2 million has been accumulated and held on the balance sheet as the cash cost of Aje crude oil inventory. US$ 0.6 million and US$ 0.2 million, both amounts relating to the first Aje cargo lifting for sales proceeds and tax receivable respectively.

Cash and bank balances stood at US$ 5.3 million at 31 December 2016, of which US$ 0.5 million cash was set aside as security of costs in relation to the ongoing dispute on OML 113), a decrease from US$ 10.9 million at 31 December 2015. The decline is due to investment in assets and corporate expenses in the period, offset by the receipt of revenues for the two Aje liftings in the period.

Equity amounted to US$ 54.3 million as per 31 December 2016, compared to US$ 108.2 million at the end of December 2015. The change reflects the loss for the period, accentuated by the impairment charges against both Aje and Dussafu, offset by the capital increase in 2016.

Total non-current liabilities of US$ 2.0 million as of 31 December 2016 compared to US$ 6.2 million at the end of December 2015. The decrease primarily relates to the reversal of the Aje Field deferred tax liability which has been unwound as part of the impairment review of the Aje field. The decommissioning provision for the Aje field has remained at US$ 1.9 million for both periods. US$ 0.1 million is held in long-term liabilities and is in relation to historical tax liability in Brazil.

Current liabilities amounted to US$ 2.4 million at December 31, 2016, compared to US$ 0.7 million at the end of December 2015.

Accounts payable, accruals and other liabilities amounted to US$ 2.3 million, an increase from US$ 0.7 million at the end of December 2015. The increase represents increased operational accruals on Aje, royalty due on Aje's second lifting and higher corporate trade payables and accruals as at 31 December 2016. The tax liability of US$ 0.1 million is in relation to historical tax liability in Brazil.

7.3 MANAGEMENT'S DISCUSSIONS AND ANALYSIS OF CASH FLOWS

7.3.1 Three months ended 30 September 2018 vs 30 September 2017

Operating cash outflow in the three months to 30 September 2018 was US$ 1.7 million compared to a cash outflow of US$ 1.3 million in the same period in 2017. The movement is primarily explained by working capital movements in the comparative period.

In the third quarter of 2018, investing cash inflows were US$ 7.2 million compared with no cash flow movement for the same period in the previous year. The net cash inflow in 2018 mainly relates to US$ 8.6 million cash retained after completion adjustments as part of the acquisition of

DNO Tunisia AS (now renamed to Panoro Tunisia Exploration AS), offset by the net effect of investment in Dussafu of US$ 6.3 million, funded to a value of US$ 5.2 million through the non-recourse loan from the Operator BW Energy. The zero cash flow movement in the three months ended 30 September 2017 is the net effect of investment in Dussafu of US$ 6.2 million, fully funded through the non-recourse loan from the Operator BW Energy.

Net cash flow from financing activities represented a cash inflow of US$ 8.5 million during the three months to 30 September 2018, predominantly comprising of the net proceeds from equity private placement and sale of treasury shares. The movement in restricted cash of US$ 0.1 million in this period relates to cash held in relation to a labour dispute inherited as part of the DNO acquisition. This compares to a cash outflow in the same period in the previous year of US$ 0.5 million, predominantly as a result of cash used for the buyback of shares in the Company.

Foreign exchange impact on cash balances was negligible during both quarters.

7.3.2 Nine months ended 30 September 2018 vs 2017

Operating cash outflow for the nine months ended 30 September 2018 was US$ 4 million compared to a cash outflow of US$ 0.4 million for the nine months ended 30 September 2017. The movement is primarily explained by working capital movements in the comparative period.

In the nine months ended 30 September 2018, investing cash inflows were US$ 7.2 million compared to an inflow of US$ 4.1 million for the same period in the previous year. The net cash inflow in 2018 mainly relates to US$ 8.6 million cash retained after completion adjustments as part of the the acquisition of DNO Tunisia AS (now renamed to Panoro Tunisia Exploration AS), offset by the net effect of investment in Dussafu of US$ 14 million, funded to a value of US$ 12.9 million through the non-recourse loan from the Operator BW Energy. 2017 mainly relates to the disposal of a 25% stake in Dussafu, offset by investment in oil and gas assets.

Net cash flow from financing activities represented a cash inflow of US$ 10 million during the first nine months of 2018, predominantly comprising of the net proceeds from equity private placement and sale of treasury shares. The movement in restricted cash of US$ 1.4 million relates predominantly to US$ 1.5 million of collateral previously held, and subsequently released back to the Company against a dispute at Aje, marginally offset by US$ 0.1 million cash held in relation to a labour dispute inherited as part of the DNO acquisition. This compares to a cash outflow in the same period in the previous year of US$ 1.6 million, predominantly as a result of cash held as collateral against the dispute at Aje and cash used for the buyback of shares in the Company.

Foreign exchange impact on cash balances was negligible during both periods.

7.3.3 Year ended 31 December 2017 vs 31 December 2016

Net cash flow from operating activities amounted to negative US$ 2.0 million in 2017, compared to negative US$ 2.6 million in 2016. The decline is primarily explained by lower costs in 2017 brought about by a reduction in exploration and related G&A costs resulting from the sale of 25% of Dussafu, combined with cost saving initiatives introduced by Management such as conducting a tender process for the Group's statutory audits, reduction in the use of third-party consultants, bringing projects in-house, reduction in seismic and geological software licenses and renegotiating terms with long-standing suppliers.

Net cash flow from investing activities was an inflow of US$ 5.1 million in 2017, compared to an outflow of US$ 11.8 million in 2016. The net cash inflow in 2017 mainly relates to the disposal of a 25% stake in Dussafu, offset by investment in oil and gas assets.

Net cash flow from financing activities represented a cash outflow of US$ 1.6 million in 2017, predominantly comprising US$ 1.0 million of movement in restricted cash where US$ 1.5 million was held as collateral against our dispute at Aje, however funds were returned to the Company post-period end. In addition to this, the Company purchased 1,000,000 of its own shares for approximately US$ 0.5 million. This compares to a cash inflow in 2016 of US$ 8.3 million, where proceeds from a private placement of US$ 8.8 million were offset by US$ 520 thousand of restricted cash, held in connection with the dispute at Aje.

Foreign exchange impact on cash balances was a positive US$ 3 thousand in 2017 and a negative US$ 10 thousand in 2016.

Cash and cash equivalents thus increased to US$ 6.3 million.

7.3.4 For the year ended 31 December 2016 vs 31 December 2015

Net cash flow from operating activities amounted to negative US$ 2.6 million in 2016, compared to negative US$ 6.5 million in 2015. The decline is primarily explained by lower costs throughout 2016 brought about by cost saving initiatives introduced by Management.

Net cash flow from investing activities was an outflow of US$ 11.8 million in 2016, compared to an outflow of US$ 23.5 million in 2015. The cash outflow in 2016 mainly relates to investment in oil and gas assets.

Net cash flow from financing activities represented a cash inflow of US$ 8.3 million in 2016, predominantly comprising US$ 8.8 million of net proceeds from a private placement, net interest income from investments US$ 18 thousand offset by US$ 520 thousand of restricted cash. This compares to a cash inflow from financing activities of US$ 59 thousand in 2015.

Foreign exchange impact on cash balances was a negative US$ 33 thousand in 2016 and a negative US$ 25 thousand in 2015.

Cash and cash equivalents thus declined to US$ 4.8 million (2015: US$ 10.9 million).

7.4 INVESTMENTS

7.4.1 Historical investments

The table below summarizes the Company's investments in years 2014 to 2017 and for the nine months ended 30 September 2018 (US$ 000):

	2014	2015	2016	2017	30 Sept 2018
Licenses, exploration assets and development assets	13,417	2,827	1,876	2,993	-
(Of which expensed)	(1,523)	(829)	(583)	(211)	-
(Of which transferred to development assets)	(6,537)	-	-	-	-
Development assets	6,537	25,026	10,979	1,380	-
Production assets	-	-	1,231	12,273	14,024
Discontinued operations / held for sale assets	-	-	-	-	-
Total principle investments	11,894	27,024	13,503	16,435	14,024

In August 2018, the Company has acquired DNO Tunisia AS for no cash consideration and deferred consideration of US$ 13.2 million payable on achieving operational milestones described in section 8.2.1. A total of US$ 10.5 million of assets were acquired together with a corresponding set of liabilities mainly towards unfulfilled license obligations, thereby making the consideration nil. The DNO Transaction has strategic value for Panoro, which provides access to local establishment and interest in exploration licenses (subject to renewal). In conjunction with the OMV Transaction, the organisation set-up acquired with DNO Transaction will supplement Panoro in becoming in developing a foothold in a new geography.

There were no significant investments made after 30 September 2018.

Nine months ended 30 September 2018

During the first nine months of 2018, Panoro invested US$ 14 million in Dussafu, of which US$ 12.5 million was carried by the operator, BW Energy through its non-recourse loan to Panoro. All costs related to the fast track development of the Dussafu Licence, ensuring the JV partners achieved the completion of Phase 1 Dussafu development on time and on budget, culminating in first oil production in September 2018, as forecasted. To achieve this, US$ 5.4 million was invested to drill and complete the two production wells, DTM-2H and DTM-3H, with additional investment of US$ 0.6 million on the DTM-3 appraisal side-track. Costs related to the FSPO, BW Adolo, its deployment and subsea hook-up operations, drilling of DRNEM-1 and project management, planning and long-lead inventory costs were US$ 8 million.

During the third quarter 2018, the Company has completed the acquisition of 100% of the shares in DNO Tunisia AS (subsequently renamed to Panoro Tunisia Exploration AS; "**PTE**") from DNO ASA. Although, there was no cash consideration payable on completion, DNO is to receive a deferred consideration of up to US$ 13.2 million paid from future production from the operated Sfax Offshore Exploration Permit. By virtue of the acquisition, Panoro assumed all existing permit rights and unfulfilled work obligations and at completion, and the cash balance of US$ 8.6 million in DNO Tunisia AS. An estimated penalty payment of US$ 3 million is due for historical breach of work program obligations, offset by a cash receipt of US$ 1.1 million from a former joint venture partner for their portion of the estimated penalty.

2017

During 2017, Panoro completed the sale of a 25% of its working interest in the Dussafu license to BW Energy for US$ 12 million, with BW Energy also providing a non-recourse loan of up to US$ 12.5 million to progress the fast-track Dussafu development. Having committed US$ 1 million in the first half of 2017 towards engineering and drilling management projects, Panoro approved the new operator's proposed work program and budget in July 2017, to move forward at full speed with the development of the Dussafu oilfields, offshore Gabon. In doing so, Panoro committed to a further US$ 1.5 million for the remainder of 2017, towards the development plan consisting of two initial wells at Tortue in the Gamba and Dentale reservoirs. During the second half of 2017, the development of the Tortue oil field continued according to plan with various installation activities carried out in preparation for the drilling and main installation phase at Tortue. The contract for the use of the Adolo FPSO was agreed and the Field Development Plan approval obtained from the Gabonese Government. The development gathered pace throughout 2017, with investment of US$ 0.6 million for the commencement of drilling activities on the first two development well, DTM-2H and DTM-3H and subsequent side-track well to DTM-3.

During 2017 at Aje, the existing Aje-5 well was re-entered successfully, before being subject to a workover intervention and subsequent necessary side-track of the well, which during this work timeframe reduced Aje's productivity and incurred costs of approx. US$8 million. Subsequently, the Aje field returned to the expected production levels of both the Aje-4 and Aje-5 wells, with the Aje-4 well producing from the Cenomanian oil reservoir and the Aje-5 well producing from the oil rim of the Turonian reservoir, averaging 307 barrels of oil per day net to Panoro. There were four oil liftings from the field during 2017 generating revenue of US$ 6 million from the sale of Panoro's net entitlement volume of 113,367 bbls.

2016

Activities in Dussafu during the year for approx. US$ 0.8 million were with the agreement of both Joint Venture (JV) partners, limited to subsurface studies to enhance the prospect inventory and further refinement of drilling plans for a potential development. However, ongoing discussions during that time with potential farm-in partners were the major focus for 2016, while also examining other initiatives such as refined development plans. As such, JV partners engaged to move the project forward with purchase of long lead equipment for approx. US$ 0.4 million for the development that started at the Tortue field, ultimately leading to first oil at Dussafu in 2H 2018.

The Aje field development progressed during the first half of 2016, with an investment of approx. US$ 1.7 million for the completion of two production wells, Aje-4 and Aje-5 in readiness for first oil. Production was expected from both wells from the Cenomanian oil reservoir. Additional investment during 2016 of approx. US$ 8.9 million related to the Front Puffin FPSO facilities and moorings, subsea flowlines, umbilicals and subsea control systems, all facilitating the hook up to the pre-installed STP buoy and preparations being made for the first introduction of hydrocarbons, with first oil production in May 2016. Stabilised production through to the end of the year culminated in average production of 515 barrels of oil per day net to Panoro. There were two oil liftings from the field during 2016 generating revenue from the sale of Panoro's net entitlement volume of 110,539 bbls.

2015

Development assets costs related to spending on OML 113 license during the year was US$ 25.0 million excluding US$ 1.0 million that was expensed to the statement of comprehensive income and did not meet capitalisation criteria. The majority of the costs spent in 2015 on the Aje project related to drilling and completion activities and payments for mobilisation of the FPSO.

Exploration on the Dussafu license was US$ 2.8 million (including US$ 0.8 million that was expensed to the statement of comprehensive income as it did not meet capitalisation criteria), mostly related to technical studies on the existing discoveries and interpretation and processing of 3D seismic data.

2014

Spending on Aje license during the year was US$ 7.1 million (including US$ 0.5 million that was expensed to the statement of comprehensive income as it did not meet capitalisation criteria), related to acquisition of 3D seismic, preparation and progression of Field Development Plan and procurement and ordering of FPSO, umbilical flowlines, manifold and control systems. After taking Final Investment Decision on phase 1 of the Aje two well oil development, US$ 6.5 million transferred to development assets.

On the Dussafu license, the Company's spending was US$ 6.3 million (including US$ 1.0 million that was expensed to the statement of comprehensive income as it did not meet capitalisation criteria) mostly related to pre-FEED studies and progression towards securing Field Development Plan approval and granting of the Exclusive Exploitation Authorisation Area.

7.4.2 Investments in progress and firm commitments

Subsequent to 30 September 2018, by virtue of the arrangement with Beender, Panoro has contributed all shares in PTE to Sfax Petroleum Corporation AS, which is the vehicle used for the joint venture with Beender Petroleum for the joint development of investments in Tunisia. As a result, all of the investment in progress and firm obligations in PTE mentioned above are reduced to Panoro's 60% participating interest in Sfax Petroleum Corporation AS.

As part of the DNO Transaction, as of 30 September 2018, the group has acquired (prior to Beender participation) unfulfilled work obligations of an estimated US$ 8 million long term and US$ 3 million short term as part of the Transaction. These relate to an estimate to meet the minimum work commitments as per license terms in Hammamet (under relinquishment) and Sfax Offshore Exploration Permit. These may be funded by either of or a combination of existing cash resources, cash flows from producing assets with the additional option to utilise the Mercuria Junior Loan facility described in section 8.3.1.Immediate investments in progress includes expenditure on OMV acquisition of US$ 18 million from Private Placement proceeds. Other future investments are likely to include development capital for oil and gas development projects particularly in Gabon and Tunisia of approximately US$ 8 million (after Beender participation) and general working capital of US$ 2 million. It is not possible to allocate specific amounts or specify timing for Gabon and Tunisia development projects as investment decisions are dictated by JV operators' investment decisions, plans, availability of equipment (e.g. rigs and long lead items) and budgets which have not yet been sanctioned or committed at joint venture level by Panoro.

7.5 RECENT DEVELOPMENT AND TRENDS

In July 2018, the Company announced completion of the acquisition of PTE (the DNO Transaction). The acquisition is a strategic fit for growth plans to establish a portfolio of assets in Tunisia. The transaction has provided Panoro with an established team in place and access to two new assets in a new geography. In addition to assuming the unfulfilled work obligations as part of the transaction, PTE also retained approximately US$ 8.6 million in cash.

A private placement of 10% of the Company's share capital and sale of treasury shares was also launched simultaneously with the transaction in June 2018 which resulted in a significantly oversubscribed issue, raising gross proceeds of US$ 8.3 million net to Panoro. DNO ASA also participated in the private placement with a subscription equivalent to approximately 5.64% of the total enlarged outstanding shares of the Company at the time of subscription. The June 2018 private placement and sale of treasury shares settled and during the third quarter.

In September 2018, the Company achieved first oil production from the Tortue field and concluded the successful drilling and completion of the Ruche North East (DRNEM-1) appraisal well located within the Dussafu PSC, offshore Gabon.

The Company has raised US$ 30 million in a Private Placement significantly strengthening its liquidity position. See section 5 "*The Private Placement*" for further information about the Private Placement.

Except as set out above, the liquidity effects of the Private Placement as described in section 8.2 "*Capitalisation and indebtedness*", there have been no significant changes in the financial or trading position of the Group since the date of its latest financial information included in this Prospectus.

7.6 EXTERNAL FACTORS AFFECTING THE BUSINESS

The Company faces several external factors that affect its business:

7.6.1 Demand

- Cost of oil relative to the cost of other energy sources such as renewables, nuclear, etc.;
- Commodity prices, included but not limited to oil prices, coal prices, and renewable energy prices.
- The availability of alternative energy sources;
- Customer's preferences to quality of the oil product;
- Expectations regarding future energy prices;
- Technological changes that could make other sources of energy more competitive than oil;

7.6.2 Regulatory, political, economic and environmental conditions

- Changes in law and regulations affecting the oil exploration and production industry;
- Political and military conflicts;
- Negative global or regional economic or political conditions, as well as environmental concerns and regulations, particularly in oil consuming regions, which could reduce energy consumption or growth in energy consumption;
- Changes in corporate tax regimes;
- Import and export bans;
- Strikes and wage fluctuations

7.6.3 Supply

- The cost of oil extraction and the number of new wells to be drilled;
- Environmental requirements;
- The depletion rate of older producing oil fields;
- The number of oil barrels on storage worldwide;
- Weather conditions; and
- Prevailing oil prices

7.6.4 Financial markets

- Currency fluctuations;
- Availability of credit and other forms of financial liquidity; and
- Increases in the supply of oil

7.7 SUMMARY OF THE OMV TRANSACTION

7.7.1 Overview

On 6 November 2018 Panoro's newly incorporated 60% jointly controlled company Panoro Tunisia Production AS ("**Buyer**") reached an agreement (the "**Agreement**") with OMV Exploration & Production GmbH (the "**Seller**") to acquire OMV Tunisia Upstream GmbH (the "**Target**"). The Target holds a 49% interest in five oil production concessions in Tunisia and 50% of Thyna Petroleum Services ("**TPS**") which serves as the operating company for the concessions. OMV's reasons to sell the Target (the "**OMV Transaction**") was to focus on larger projects in the south of Tunisia.

The Target has participation in five concessions namely, Guebiba/El Hajib, Rhemoura, El Ain, Cercina, and Cercina South (together, the "**Concessions**") which are located onshore and offshore near the city of Sfax, and bordering Panoro's recently acquired Sfax Offshore Exploration Permit ("**SOEP**"). The oil fields on these Concessions at present collectively produce approximately 2,000 bopd net to the Target's share from 14 wells. The fields have been in production since the 1990s, avail of full infrastructure to handle and transport crude oil, and are managed with disciplined HSE standards. The remaining interest in the Concessions and TPS is held by ETAP, the Tunisian state oil company.

The Concessions are also positioned to unlock the potential in SOEP. SOEP's discoveries and prospects can in the future be tied into the existing TPS infrastructure and pipeline system. The combination of the Concessions and SOEP enables the long-term future to be realised to the benefit of Panoro, ETAP and Tunisia. The Concessions hold significant strategic value for Panoro in realising its goal of becoming a full cycle E&P company with high quality assets, well managed operations, in a focus country.

The Concessions are currently jointly-managed and jointly-operated by ETAP and the Target through TPS, a long standing and respected joint-venture operating company. TPS is located in the city of Sfax and has approximately 180 employees and contractors. Panoro will have the right to appoint the Deputy General Manager and Development Manager in TPS. The future strategy and work programme at TPS will be jointly managed by Panoro and ETAP (the "**TPS JV**") and the TPS JV have already identified several opportunities to increase production and reserves from the Concessions.

The consideration for the OMV Transaction is US$ 65 million (the "**Consideration**") which is payable in cash and with an effective date of 1 January 2018. At completion which is expected to take place on or about 19 December 2018, a downward, preliminary adjustment of the Consideration will be made, expected to be approximately US$ 14.5 million representing completion adjustments as per the agreement, offset by US$ 2 million of working capital adjustments (reflecting a payment for crude and materials inventory) million and a net of cash of approximately US$ 4.5 million remaining with the Target) resulting in a final payable amount of US$ 57 million.

7.7.2 Background and the reason for the OMV Transaction

The Board of Directors' strategy for Panoro Energy over the past few years has been to become more focused for growing its position in Africa through continuing an active search for new opportunities to grow its business through value accretive acquisitions. In conjunction with the recent acquisition of DNO Tunisia AS, which Panoro acquired from DNO ASA, the OMV Transaction offers significant synergies in the form of a well-established organisation structure in country to manage the assets and harness the full potential of the concessions. The OMV Transaction also adds a sizeable production in Panoro's portfolio and complements the strategy and growth plans the Company aspires to achieve.

This OMV Transaction not only fully addresses the Board of Directors strategic guidance, but will further strengthen the Company and build an even stronger platform to take advantage of longer-term growth opportunities in Africa. As a consequence, the OMV Transaction has centred on two main priorities:

- Maximization of shareholder value through value accretive acquisitions, and
- Ensure balanced growth while retaining a strong financial position

7.7.3 The significance of the OMV Transaction to the Company

The OMV Transaction is in itself transformational for the Company which will increase Panoro's assets by approximately 240% compared to the 2017 audited statement of financial position. Furthermore, the OMV Transaction is expected to significantly increase Panoro's current oil production from the Dussafu and Aje fields. Furthermore, the increase in production will also have a significant effect on the revenue generated by the business on an annual basis.

As a result of the OMV Transaction the Company will:

- Be able to take on new growth and opportunities within the portfolio and unlock value in Tunisia;
- Reduce financial risk and diversification in the asset portfolio;
- Have an improved cash situation and capital structure creating a platform for growth further growth plans

7.7.4 OMV Exploration and Production GmbH (the "Seller")

The Seller is a fully owned subsidiary of OMV Aktiengesellschaft ("**OMV**") and holds, amongst many other interests, investment in the Target. OMV is producing and marketing oil and gas with group sales of EUR 20 billion and a workforce of around 20,700 employees in 2017 making OMV Aktiengesellschaft one of Austria's largest listed industrial companies.

7.7.5 The structure and consideration of the OMV Transaction

The OMV Transaction comprises the acquisition of all shares in the Target which holds a 49% share in five producing concessions and a 50% investment in TPS. The OMV Transaction is funded through a combination of proceeds from the Private Placement, investment proceeds from a co-investor Beender Petroleum Tunisia Limited ("**Beender**") and a secured acquisition loan ("**Mercuria Loan**") from Mercuria Asset Holdings (Hong Kong) Ltd ("**Mercuria**") (details are given in section 7.7.7 below).

The consideration for the shares in the Target comprises a base consideration of US $65 million, reduced by approximately US$ 14.5 million representing completion adjustments, offset by working capital adjustments of US$ 2 million (reflecting a payment for crude and materials inventory) and net cash of approximately US$ 4.5 million remaining with the Target at completion, resulting in the estimated final payable amount to US$ 57 million.

No agreements have been entered into in connection with the OMV Transaction for the benefit of the Company's senior employees or board members of the Company and no such agreements are expected to be entered into.

The OMV Transaction will be funded from the following sources (numbers are approximate):

- Senior secured loan from Mercuria US$ 27 million
- Investment from Beender US$ 12 million
- Private Placement and existing cash US$ 18 million

7.7.6 Joint Arragement with Beender

In November 2018, Panoro has agreed a strategic Joint Arrangement with Beender, a privately held oil and gas company focussed on proven oil fields with upside. Through the agreement, Beender and Panoro have agreed to jointly pursue all Tunisian opportunities through a new holding company Sfax Petroleum Corporation AS ("**Sfax Petroleum**"), which is the holding company for the Buyer and the recently acquired PTE. Beender has agreed to subscribe in cash for shares giving it 40% of Sfax Petroleum and will fund its pro-rata share of the Buyer's equity requirement at the completion of the acquisition (US$ 12 million). Through its subscription for shares of Sfax Petroleum, Beender will acquire a pro rata share of all benefits and liabilities associated with the Panoro's Tunisian businesses. Beender and Panoro have agreed a shareholder agreement and subscription agreement which sets out the basis for the operation and governance of the Sfax Petroleum.

7.7.7 Mercuria Loan

Mercuria Energy Group Holding SA, one of the world's largest independent energy traders, through its subsidiary Mercuria Asset Holdings (Hong Kong) Ltd ("**Mercuria**"), is providing an acquisition Senior Secured Loan facility of US$ 27 million ("**Senior Loan**") to the Buyer. In addition, Mercuria will make an additional junior loan facility available for a further $8 million ("**Junior Loan**"), which the Buyer will retain as an option at this time.

Key terms of the Senor Loan and Junior Loan arrangements are set out in section 8.3 “Borrowings”.

7.7.8 Description of OMV Tunisia Upstream GmbH (the “Target”)

7.7.8.1 Overview

OMV Tunisia Upstream GmbH, a company organised and existing under the laws of Austria, registered at the Commercial Court of Vienna under number 476279k and having its registered address at Trabrennstrasse 6-8, 1020 Vienna, Austria.

7.7.8.2 Board of Directors and management

The Board of Directors of the Target are Seller nominated personnel that will resign on completion of the OMV Transaction and will be replaced by Panoro nominated Directors from current management.

7.7.8.3 Employees

The Target has no employees as of the date of this Prospectus.

7.7.8.4 Business of OMV Tunisia Upstream GmbH

The Target holds a 49% interest in five oil production concessions in Tunisia and 50% of TPS which serves as the operating company for the concessions.

The Concessions are located onshore and offshore near to the city of Sfax, and bordering Panoro’s recently acquired SOEP. The oil fields together currently produce approximately 2,000 bopd net to Target’s share from 14 wells. The fields have been in production since the 1990s, avail of full infrastructure to handle and transport crude oil, and are managed with disciplined HSE standards. The remaining interest in the Concessions and TPS is held by ETAP, the Tunisian state oil company.

7.7.8.5 Material contracts

The Target, has not for the two years immediately preceding the date of this Prospectus, entered into any material contract, other than contracts entered into in the ordinary course of business.

7.7.8.6 Financial Information of the Target

The historical information of the Target has been extracted without adjustments, from the accounting records of the Seller. The accounting policies adopted and applied on preparation of this extracted unaudited historical financial information of the Target are consistent with the policies of the audited Group accounts which have been incorporated by reference. Due to lack of availability of historical information that is consistent with Panoro’s accounting policies, only the statement of financial position as of 30 September 2018 has been included below that represents the provisional Purchase Price Allocation of the consideration payable.

7.7.8.6.1 Acquisition of the Target

	Panoro's Share **At 60%** *US$ '000*
Purchase Price Allocation	
<u>Assets</u>	
Goodwill	16,589
Production reserves	29,104
Investment in associate / Joint venture	38

	Panoro's Share At 60%
	US$ '000
Production assets and equipment	16,568
Development assets	701
Other non-recurrent assets	140
Crude oil inventory	1,063
Inventories	2,687
Trade and other receivables	3,137
Cash and cash equivalents	2,700
TOTAL ASSETS	**72,727**
Liabilities	
Provision for decommissioning	16,421
Provision of current taxes	3,887
Trade and other payables	1,026
Non-financial liabilities	602
Deferred tax liability	16,589
TOTAL LIABILITITES	38,525
NET ASSETS ACQUIRED	**34,202**

Panoro's entitlement of the acquired assets and liabilities has been represented at 60% as per the Joint Arrangement with Beender.

7.7.8.6.2 Operational and Financial Metrics

As noted in section 7.7.8.6 above, pro forma income statement information is not provided due to a lack of available historical information which is consistent with the policies of the audited Group accounts. The following information is presented instead, having been extracted without adjustments, from the records of the Seller:

Nine months ended 30 September 2018	**Target**	**Panoro's share at 60%**
Income statement		
Sales revenues (US$ 000)	28,635	17,181
Estimated taxes on income (US$ 000)	(10,777)	(6,466)
Production for the period (Target's portion) (bbls)	522,320	313,392

7.7.8.6.3 Significant Change

No significant change to the acquired assets and business operations is expected post completion of the OMV Transaction.

7.8 UNAUDITED PRO FORMA FINANCIAL INFORMATION

7.8.1 Pro forma requirement and the OMV Transaction

On 7 November 2018, Panoro Tunisia Production AS (the "**Buyer**") signed an agreement with OMV Exploration & Production GmbH (the "**Seller**") to acquire 100% of the shares in OMV Tunisia Upstream GmbH ("**OMV Tunisia**"). OMV Tunisia holds a 49% interest in five oil production concessions in Tunisia and 50% of Thyna Petroleum Services SA ("**TPS**"), which serves as the operating company for the concessions. This transaction is hereafter referred to as the "**OMV Transaction**". The details of the OMV Transaction can be further referred to in section 7.7 of this document.

The consideration for the shares in OMV Tunisia comprises a gross base consideration of US $65 million, reduced by approximately US$ 14.5 million representing completion adjustments, offset by working capital adjustments of US$ 2 million reflecting a payment for crude and materials inventory and net cash of approximately US$ 4.5 million remaining with OMV Tunisia, thereby reducing the final payable amount to US$ 57 million. The cash consideration of US$ 57.0 million is expected to be paid upon closing of the OMV Transaction. Panoro's effective participation in the OMV Transaction is 60% ownership through Sfax Petroleum Corporation AS (as discussed below in section 7.7.6), whereby will be liable for US$ 34.2 million of the cash consideration.

In order to fund the OMV Transaction, the following funding arrangements have been made:

- Panoro has issued new shares through an equity private placement of US$ 30 million in December 2018. The use of proceeds amongst others, includes payment of Panoro's share of the OMV Transaction consideration. The equity private placement in connection with the OMV Transaction has been further described above in section 7.7 and is herein referred to as the "**Private Placement**".

- Panoro has entered into a joint arrangement with Beender Petroleum Tunisia Limited ("**Beender**"), by establishing a Norwegian domiciled, jointly controlled company Sfax Petroleum Corporation AS (hereafter referred to as "**Sfax Corp**"). Sfax Corp is the holding company of Panoro Tunisia Production AS. Panoro's equity ownership in Sfax Corp is 60% whereas Beender holds the remaining 40%.

  The holding structure post OMV Transaction with Beender is as follows:

  - Panoro and Beender holds 60% and 40% respectively, of the shares in Sfax Corp.
  - Sfax Corp through holding subsidiaries holds 100% shares in OMV Tunisia.
  - Panoro therefore effectively holds 60% interest in OMV Tunisia by virtue of the Joint Arrangement with Beender through 60% investment in Sfax Corp.

- Panoro has arranged a Senior Secured loan facility of US$ 27 million from Mercuria Asset Holdings (Hong Kong) Ltd. ("**Mercuria**") as described in section 8.3.1. Panoro Tunisia Production AS, in which Panoro has 60% indirect interest through a joint arrangement with Beender, is the holder of the facility.

Panoro's share of the OMV Transaction consideration is to be funded through the Private Placement and Panoro's portion of the loan by Mercuria amounting to US$ 16.2 million hereafter referred to as the "**Financing**".

The OMV Transaction is expected to complete on or about 19 December 2018 and represents a significant gross change as defined in Commission Regulation (EC) No. 908/2004 of 29 April 2004, which sets out the requirements to prepare pro forma financial information that needs to be included in a prospectus.

The acquisition of OMV Tunisia and the financing are for the purpose of the unaudited condensed pro forma financial information referred to as the "**Transactions**". The unaudited condensed pro forma financial information is prepared to illustrate how the Transactions would have affected the Company's statement of financial position as of 31 December 2017 had they been completed on that date.

Annex II of the Commission Regulation requires the preparation of a pro forma statement of financial position as of 31 December 2017 as if the Transactions occurred on that date and a pro forma statement of profit and loss for 2017 as if the Transactions occurred on 1 January 2017.

Due to the following reasons, no pro forma profit and loss financial information has been prepared as if the Transactions were completed on 1 January 2017:

- OMV Tunisia, for 2017, lacks allocation of company overhead costs and other items required to provide a complete and relevant income statement; and
- The assets have been carved out from the Seller's own books and due to confidentiality restrictions, the Company does not have access to the necessary historical information to extract relevant historical income statement financial information for 2017.

7.8.2 Joint Arrangement with Beender

Beender, a fully owned subsidiary of Beender Petroleum Limited, a privately held oil and gas company focussed on proven oil fields with upside, has participated in the acquisition of the OMV Tunisia together with Panoro and by virtue of a strategic agreement, Beender and Panoro have agreed to jointly pursue all Tunisian opportunities through a new holding company Sfax Corp, which is the holding company of OMV Tunisia and PT Exploration. Beender has agreed to subscribe in cash for shares giving it 40% of Sfax Corp which, together with Beender's share of the Mercuria facility, to fund its pro-rata share of the Buyer's consideration at the completion of the acquisition. Through its subscription for shares of Sfax Corp, Beender will have effectively acquired a 40% pro rata share of all benefits and liabilities associated with the Panoro's Tunisian businesses. Beender and Panoro have entered into a shareholder agreement which sets out the basis for the operation and governance of the Sfax Corp.

7.8.3 Purpose of the unaudited condensed pro forma financial information

The unaudited condensed pro forma financial information set out below has been prepared by the Company for illustrative purposes to show how the Transactions might have affected the statement of financial position as of 31 December 2017 as if they occurred on that date.

The qualitative description of the potential impact on the Company's income statement for the year 2017, had the OMV Transaction completed on 1 January 2017, has been included in section 7.8.9.

The unaudited condensed pro forma financial information has been compiled to comply with the Norwegian Securities Trading Act and the applicable EU-regulations pursuant to section 7-7 of the Norwegian Securities Trading Act. This information is not in compliance with SEC Regulation S-X, and had the securities been registered under the U.S. Securities Act of 1933, this unaudited Pro Forma Financial Information, including the report by the auditor, would have been amended and /or removed from the Prospectus.

The assumptions underlying the pro forma adjustments, for purpose of deriving the unaudited pro forma financial information, are described in the notes to the condensed unaudited pro forma financial information. Neither these adjustments nor the resulting unaudited pro forma financial information have been audited in accordance with Norwegian generally accepted auditing standards. Each reader should carefully consider the financial information of the Company and the notes thereto and the basis for preparation, accounting policies and the notes to the unaudited pro forma financial information.

The unaudited condensed pro forma financial information does not include all of the information required for financial statements under IFRS and should be read in conjunction with the historical financial information of the Company.

7.8.4 Basis of preparation

The sources of the historical unadjusted financial information included in the pro forma statement of financial position as of 31 December 2017 are:

- For the Company, the audited consolidated financial statements for the period ended 31 December 2017 prepared in accordance with International Financial Reporting Standards as adopted by the EU (IFRS). The audited consolidated financial statements are included in Appendix 4 to this Prospectus. EY issue an unqualified audit opinion on the Company's 2017 financial statements with no matters of emphasis reported.
- For OMV Tunisia, the unaudited statement of financial position as of 31 December 2017 has been extracted from the underlying accounting records reported as part of the audited consolidated financial statements of OMV Aktiengesellschaft prepared under IFRS as adopted by the EU. The account balances were mapped to the Company's chart of accounts in order to align the balances to the statement of financial position line items of the Company.

The unaudited pro forma financial information has been prepared under the assumption of going concern. All of the financial information in the pro forma is prepared and presented in US$ thousands, unless stated otherwise.

7.8.5 Accounting policies applied

The consolidated financial statements of the Company have been prepared in compliance with IFRS as adopted by the EU. The unaudited pro forma financial information has been compiled using accounting policies consistent with those applied by the Company in 2017.

The Company will not adopt any new policies in 2018 as a result of the acquisition or otherwise, with the exception of IFRS 15 and IFRS 9 which have been adopted by the Company effective from 1 January 2018. Please refer to the financial statements for 2017 for description of the accounting policies.

The financial information for the OMV Tunisia is extracted from underlying accounting records reported as part of the audited consolidated financial statements of OMV Aktiengesellschaft prepared under IFRS as adopted by the EU for the year ended 31 December 2017. Accounting policies are consistent with those applied and adopted in the Company's financial statements for the year ended 31 December 2017. The unaudited pro forma financial information includes unaudited pro forma statement of financial position as of 31 December 2017, and descriptions and notes to the unaudited pro forma financial information.

Following the OMV Transaction, a review of key accounting policies has been made, in order to identify policies that could be applicable to the Company and need to be adopted for the purpose of preparing the pro forma financial information. Based on this review, the following key accounting policy has been adopted for the purpose of the preparation of the Company's financial statements for the year ended 31 December 2018, and also in the preparation of unaudited pro forma financial information:

a) *Associated companies and joint arrangements*

As described in section 7.7.6, Panoro will enter into a joint arrangement through a shareholder agreement with Beender, whereby Panoro and Beender jointly own and control 60% and 40% of Sfax Corp respectively The Sfax Corp, through its subsidiaries holding 100% shares in the Buyer, OMV Tunisia and PT Exploration.

Associated companies are those entities in which the Company has significant influence, but not control or joint control over the financial and operating policies. Joint arrangements, which are arrangements of which the Group has joint control together with one or more parties, are classified into joint ventures and joint operations. Joint ventures are joint arrangements in which the parties that share control have rights to the net assets of the arrangement. Joint operations are joint arrangements in which the parties that share joint control have rights to the assets, and obligations for the liabilities, relating to the arrangement.

For joint operations, the Company's share of all assets, liabilities, income and expenses is included in the consolidated financial statements. Acquisitions of interests in a joint operation, in which the activity of the joint operation constitutes a business, are accounted for according to the relevant IFRS 3 principles of accounting for business combinations.

OMV Tunisia has a 49% interest in five oil and gas concessions alongside ETAP at 51%. In addition, OMV Tunisia owns 50% of the shares in Thyna Petroleum Services SA ("TPS") which operates the five oil and gas concessions. TPS being a joint operating company, is not considered a subsidiary of OMV Tunisia.

The 49% interest in the five oil and gas concessions are managed through an operating agreement between OMV Tunisia and ETAP which requires unanimity in most of the operational decision making. OMV Tunisia has rights to the assets, and obligations for the liabilities, relating to the arrangement. The five oil concessions are therefore considered a joint operation.

TPS operates on a cost basis and bills all the spending back to the JV partners. The sole purpose of existence of TPS is to manage the named concessions and it does not generate any meaningful income or results. OMV Tunisia has no rights to the assets, or obligations for the liabilities, in the joint arrangement. The investment in TPS is therefore considered a joint venture and accounted for using the equity method.

Panoro's investment in Sfax Corp is 60%, which is governed by a shareholder agreement with Beender and requires unanimity of both parties in all major decision making. Panoro has a right to the assets, and obligation for the liabilities, relating to the arrangement. As a result, on application of the aforementioned accounting policy, Panoro will only include 60% of the account balances and transactions on a line by line basis in its financial statements by proportionally consolidating the results and balances of Sfax Corp and its subsidiaries and excludes TPS (which is accounted for using equity method).

7.8.6 Limitations

Due to its nature, the unaudited pro forma financial information addresses a hypothetical situation, and, therefore, does not represent the Company's actual financial position or results. Investors are cautioned not to place undue reliance on this unaudited pro forma financial information.

7.8.7 Unaudited pro forma condensed statement of financial position as of 31 December 2017

(US $ '000)	Panoro Energy ASA (consolidated) IFRS 31/12/2017	OMV Tunisia Upstream GmbH IFRS 31/12/2017 (unaudited)	Pro forma adjustments 31/12/2017 (unaudited)	Notes	Pro forma 31/12/2017 (unaudited)
ASSETS					
Non-current assets					
Intangible assets					
Goodwill	-	-	16,589	(a)	16,589
Licenses and exploration assets	13,596	-	-		13,596
Production rights	-	-	29,104	(a)	29,104
Total intangible assets	**13,596**	**-**	**45,693**		**59,289**
Tangible assets					
Production assets and equipment	9,902	19,556	-		29,458
Development assets	1,694	553	-		2,247
Property, furniture, fixtures and equipment	102	-	-		102
Deferred tax assets	-	3,083	-		3,083
Other non-recurrent assets	134	-	-		134
Total tangible assets	**11,832**	**23,192**	**-**		**35,024**
Total non-current assets	**25,428**	**23,192**	**45,693**		**94,313**
Current assets					
Crude oil inventory	1,398	453	-		1,851
Inventories	-	3,871	-		3,871
Trade and other receivables	615	2,587	-		3,202
Cash and cash equivalents	6,317	-	9,336	(e)	15,653
Restricted cash	1,500	-	-		1,500
Total current assets	**9,830**	**6,911**	**9,336**		**26,077**
TOTAL ASSETS	**35,258**	**30,103**	**55,029**		**120,390**
EQUITY AND LIABILITIES					
Equity					
Share capital	299	25	68	(a), (b), (e)	392
Share premium	297,490	-	28,007	(b),(d), (e)	325,497
Treasury shares	(503)	-	-		(503)
Additional paid-in capital	122,205	3,576	(3,576)	(a)	122,205
Total paid-in equity	**419,491**	**3,601**	**24,499**		**447,591**
Other reserves	(43,405)	-	-		(43,405)
Retained earnings	(358,766)	-	(1,997)	(a),(c),(d)	(360,763)
Total equity attributable to shareholder of the parent	**17,320**	**3,601**	**22,502**		**43,423**
Non-current liabilities					
Decommissioning liability	2,039	17,063	-		19,102
Long-term liabilities	2,197	-	15,938	(c)	18,135
Deferred tax liabilities	-	3,226	16,589	(a)	19,815
Other non-current liabilities	6,892	905	-		7,797
Total non-current liabilities	**11,128**	**21,195**	**32,527**		**64,850**
Current liabilities					
Accounts payable and accrued liabilities	6,737	-	-		6,737
Corporation tax liability	73	5,307	-		5,380
Other current liabilities	-	-	-		-
Total current liabilities	**6,810**	**5,307**	**-**		**12,117**
TOTAL EQUITY AND LIABILITIES	**35,258**	**30,103**	**55,029**		**120,390**

7.8.8 Notes to the pro forma statement of financial position

The key adjustments and assumptions that have been considered in the preparation of the pro forma financial information are included in Notes (a) to (f) below.

Note (a) Acquisition of OMV Tunisia Upstream GmbH

A preliminary Purchase Price Allocation has been prepared identifying the OMV Tunisia's assets, liabilities and contingent liabilities and necessary adjustments are being made to the Company's statement of financial position. The allocated values are preliminary due to the fact that the carrying values as a basis for allocation are on a date before the closing of the actual OMV Transaction and also the time required to finalise the closing adjustments with the Seller post completion. As a result of the closing adjustments with the Seller, the estimated fair value of the consideration might change until acquisition completion date. A revision of Purchase Price Allocation on completion date will be made in the Company's 2018 annual report.

A table of Purchase Price Allocation as of 30 September 2018 values reflecting Panoro's proportionate 60% interest in OMV Tunisia is as follows:

Purchase Price Allocation	**Panoro's share at 60%**		
Amounts in US$ 000	Carrying value	Fair value adjustment	Purchase Price Allocation
Assets			
Goodwill	0	16,589	16,589
Production rights	0	29,104	29,104
Investment in associate / Joint venture	38	0	38
Production assets and equipment	16,568	0	16,568
Development assets	701	0	701
Other non-recurrent assets	140	0	140
Crude oil inventory	1,063	0	1,063
Inventories	2,687	0	2,687
Trade and other receivables	3,137	0	3,137
Cash and cash equivalents	2,700	0	2,700
TOTAL ASSETS	**27,034**	**45,693**	**72,727**
Liabilities			
Decommissioning liability	16,421	0	16,421
Other non-current liabilities	3,887	0	3,887
Accounts payable and accrued liabilities	1,026	0	1,026
Corporation tax liability	602	0	602
Deferred tax liability	0	16,589	16,589
TOTAL LIABILITIES	**21,936**	**16,589**	**38,525**
NET ASSETS ACQUIRED	**5,098**	**29,104**	**34,202**

Deferred tax liability and Goodwill

Tax is recognised on the temporary difference between the assets' tax base and fair value recognised in the statement of financial position. For the purposes of the acquisition accounting, under IFRS, the deferred tax liability has been recognised on the fair value uplift that represents a temporary difference between the acquisition date carrying amount and the acquisition value of the assets. A tax rate of 57% has been used for computing the deferred tax liability, which is the tax rates applicable to the five concessions acquired through the OMV Transaction. As a consequence of the recognition of deferred tax liability on acquisition, a technical goodwill of the same amount has also been recognised as per the requirements of IFRS 3 – Business Combinations.

(Unaudited)	**Panoro at 60%**
	US$ 000
Fair value uplift	29,104
Deferred tax calculated at applicable tax rate of 57%	16,589
Goodwill generated on recognition of deferred tax on acquisition	16,589

Consolidation adjustments of elimination of equity balances on 31 December 2017

For the purpose of the pro forma information, share capital and additional paid in capital of OMV Tunisia's opening balances, have been reclassified to retained earnings. The effect of this adjustment is as follows:

Amounts in US$ 000	**OMV Tunisia**
	(Unaudited)
Elimination of issued share capital	-25
Elimination of additional paid in capital	-3,576
Impact of eliminations on retained earnings	3,601
Overall effect of eliminations on equity balances	0

The overall effect of the adjustments in note (a) are as follows:

- *Intangible assets have increased by US$ 45.7 million*: The entire fair value uplift of US$ 29.1 million has been allocated to the acquisition of production rights and established on a market based calculation in line with IFRS 13. As a result of this transaction, technical goodwill of US$ 16.6 million has been recognised on the acquisition date.
- *Cash and cash equivalents decreased by US$ 34.2 million*: The purchase consideration of US$ 34.2 million has been included as a cash outflow to show the payment of consideration on the closing of the OMV Transaction
- *Deferred tax liability increased by US$ 16.6 million:* Deferred tax liability has been recognised at US$ 16.6 million on the provisional purchase price allocation of the fair value uplift in accordance with IFRS 3.
- *Effect of equity balances for elimination:* The overall effect on equity balances included reduction of share capital elimination of US$ 0.03 million; additional paid in capital elimination of US$ 3.6 million; and increase in retained earnings of US$ 3.6 million. The overall effect of these eliminations was nil.
- *Effect of Fair value adjustments on retained earnings decreased by US$ 5.1 million:* The difference between the purchase consideration paid of US$ 34.2 million and US$ 29.1 million of net fair value adjustments, has resulted in a decrease of US$ 5.1 million in retained earnings. The net effect of changes in retained earnings of US $ 1.5 million described above represents the movement in net assets between 31 December 2017 and 30 September 2018 and thus eliminating the result for this period.

Taxation

An assessment of taxes has been made on the fair value adjustment at the time of acquisition, and the difference in uplift adjustment is considered a permanent difference, which is unlikely to be an allowable expense for tax purposes. For tax purposes, the tax depreciation bases will continue to be the historical tax base for each concession.

Note (b) *Equity Private Placement*

In conjunction with the OMV Transaction, Panoro launched a Private Placement in November 2018 which raised a subscription of US$ 30 million in gross proceeds. This amount has been included in the pro forma adjustments. As part of Private Placement, 15,580,000 new shares were issued each at NOK 16.10 per share and exchange rate of NOK 8.36 to US$ 1 has been used for the purpose of conversion.

The effect of this adjustment is as follows:

- Increase in cash and cash equivalents by US$ 30 million
- Increase in issued share capital by US$ 94 thousand
- Increase in share premium by US$ 29.9 million

Note (c) *Proceeds from Mercuria Loan*

Mercuria Energy, through its subsidiary Mercuria Assets Holdings (Hong Kong) Ltd ("**Mercuria**"), has provided an acquisition Senior Secured Loan facility of US$ 27 million ("**Senior Loan**") to the Buyer. In addition, Mercuria has also made available an additional junior loan facility for a further US$ 8 million ("**Junior Loan**"), which the Buyer will retain as an option and not utilise this for acquisition of OMV Tunisia. The Mercuria loan financing agreement is expected to be signed in December 2018 prior to the completion of the OMV Transaction. Details of the loan arrangement are included in section 8.3.1.

For the purpose of preparation of the pro forma financial information, it has been assumed that the gross proceeds from the Senior Tranche of Mercuria loan were drawn-down as if the draw-down had happened as of 31 December 2017. Panoro's attributable liability for Mercuria loan is 60% by virtue of the Joint Arrangement with Beender and as such has been proportionately accounted for at US$ 16.2 million in the pro forma adjustments.

Costs and fees associated with the draw-down and arrangement of the Senior and Junior loan, incurred on loan funds to be spent on the OMV Transaction are:

- Structuring fee for the Senior Loan facility - 1.25% of loan amount at US$ 0.3 million payable in cash
- Legal costs associated with loan documentation estimated at - US$ 0.1 million payable in cash

The table below summarises the net cost attributable to Panoro:

Amounts in US$ 000 – (unaudited)	**Loan facility costs - Gross**	**Panoro's share at 60%**
Senior Loan structuring fee	337	202
Legal costs	100	60
Total	437	262

The effect of the above adjustments is as follows:

- Increase in Long-term liabilities by US$ 16.2 million (Draw-down of Senior Loan)
- Increase in cash and cash equivalents by US$ 16.2 million (Draw-down of Senior loan)
- Increase in unamortised borrowing costs by US$ 0.3 million (offset for presentation purposes with Long-term liabilities)
- Decrease in cash and cash equivalents by US$ 0.3 million (payment of borrowing costs)

A reconciliation of the Senior Loan balance after adjustments is as follows:

Amounts in US$ 000 – (Unaudited)	**Loan Balance**
Long-term liabilities	16,200
Unamortised borrowing costs	-262
Long-term liabilities (net of unamortised costs)	15,938

Note (d) *Transaction costs*

The effect of transaction costs in connection with the OMV Transaction and the Private Placement has been estimated and included as an adjustment for the purposes of the preparation of pro forma information in this section. The overall estimated cost directly attributable to the equity issue is US$ 1.9 million which includes (but not limited to) fee for advisors and managers, legal costs, auditor confirmation, legal and compliance, cost of general meeting and listing and prospectus related fees. The costs in relation to the OMV Transaction is estimated at US$ 0.5 million and has been expensed in retained earnings.

The effect of this adjustment on the unaudited pro forma statement of financial position is as follows:

- Decrease in share premium account by US$ 1.9 million
- Decrease in retained earnings account by US$ 0.5 million
- Decrease in cash and cash equivalents by US$ 2.4 million

Note (e) *Reconciliation of pro forma adjustments impacting cash and cash equivalents and equity items*

A table has been prepared to reconcile the pro forma adjustments made to the cash and cash equivalents and equity items on the unaudited pro forma statement of financial position as of 31 December 2017.

Reconciliation of pro forma adjustments to:

CASH AND CASH EQUIVALENTS		*(Unaudited)*
Adjustments:	Reference	*US$ 000*
Payment of OMV Transaction purchase consideration	Note (a)	-34,202
Proceeds from Private Placement	Note (b)	30,000
Proceeds from draw-down of Mercuria Loan	Note (c)	16,200
Payment of Borrowing costs	Note (c)	-262
Payment of Transaction costs	Note (d)	-2,400
Net pro forma adjustment to cash and cash equivalents		**9,336**

SHARE CAPITAL		
Adjustments:	Reference	*US$ 000*
Private Placement	Note (b)	93
Elimination of share capital OMV Tunisia	Note (a)	-25
Net pro forma adjustment to share capital		**68**

SHARE PREMIUM		
Adjustments:	Reference	*US$ 000*
Private Placement	Note (b)	29,907
Share issue costs	Note (d)	-1,900
Net pro forma adjustments to share premium		**28,007**

ADDITIONAL PAID-IN CAPITAL		
Adjustments:	Reference	*US$ 000*
Elimination of paid-in capital OMV Tunisia	Note (a)	-3,576
Net pro forma adjustment to additional paid-in capital		**-3,576**

RETAINED EARNINGS		
Adjustments:	Reference	*US$ 000*
Fair value adjustments purchase price allocation	Note (a)	29,104
Consideration for OMV Tunisia	Note (a)	-34,202
Elimination of paid in capital OMV Tunisia	Note (a)	3,601
Acquisition costs	Note (d)	-500
Net pro forma adjustment to retained earnings		**-1,997**

7.8.9 Description of the impact on the Income Statement for 2017 if the OMV Transaction had been completed 1 January 2017

As described in section 7.8.1, had the five concessions been acquired on 1 January 2017, Panoro would have accounted for the proportionate share of revenue, operating costs, depreciation depletion and amortisation and general and administrative expenses and taxes for in relation to the OMV Tunisia. The estimate of such revenues and costs are uncertain due to lack of availability of information from the Seller, for which reasons have been explained in section 7.8.1.

Panoro Energy has recorded transaction costs of approximately US$ 0.5 million which have resulted from the OMV Transaction and as such would be been recorded in the income statement for the year ended 31 December 2017.

Furthermore, an interest charge for the Mercuria loan would have been recorded in the income statement for the year ended 31 December 2017.

7.8.10 Report on unaudited pro forma financial information ended 31 December 2017

Ernst & Young AS has issued an Independent Assurance Report in accordance with ISAE 3420 "assurance engagements to report on the compilation of pro forma financial information included in a prospectus" on the unaudited pro forma financial information included as Appendix 3. Ernst & Young AS has not audited, reviewed or produced any report on any other information provided in this Prospectus.

8. LIQUIDITY AND CAPITAL RESOURCES

Panoro Energy obtains its sources of funding from equity and debt funding.

On 7 November 2018, Panoro Energy raised gross US$ 30 million (approximately NOK 250.8 million) in new equity in the Private Placement, directed at Norwegian and international institutional investors. See section 5 "The Private Placement" for further information regarding the Company's Private Placement.

The Company has in place a non-recourse loan from BW Energy ("**BWE Loan**") in relation to the funding of the Dussafu development. As of 30 September 2018, Panoro's drawdown on the non-recourse loan was US$ 12.5 million (31 December 2017: US$ 2.2 million).

On completion of the OMV Transaction, Panoro Tunisia Production AS, a Jointly controlled company with Beender, will also draw-down on the Senior Loan of US$ 27 million (Panoro's share at 60% equals US$ 16.2 million). The details of the Mercuria Loan are included in section 8.3 below.

There are no limitations on transferring cash between the Group subsidiaries and the Company with the exception of companies owned jointly with Beender, whereby under the Mercuria Loan agreement, the borrowing company and OMV Tunisia collectively have to maintain a minimum of US$ 3.5 million of cash and cash equivalents throughout the loan term. Further details on Mercuria loan covenants is included in section 8.3.1 Cash resources representing the Group's funding resource at the date of this prospectus was US$ 38.6 million.

8.1 WORKING CAPITAL STATEMENT

Within 12 months

The Company is of the opinion that the Group's working capital is sufficient for the Group's present requirements, for the period covering at least 12 months from the date of this Prospectus. For the purpose of this statement, "working capital" means the ability to access cash and other available liquid resources in order to meet liabilities as they fall due, and "present requirements" means 12 months from the date of this prospectus.

After 12 months

From the Company's perspective, the difficulty and uncertainty with estimating cash flows beyond twelve months is caused by timing of investment decisions made by the licence partnerships and oil price fluctuations. However, with the Company's current forecasts, the working capital of the Group is forecasted to be sufficient through this period.

8.2 CAPITALISATION AND INDEBTEDNESS

The information presented below should be read in conjunction with the other parts of this Prospectus, in particular section 6 "Consolidated Financial Information", and the Financial Statements and Interim Financial Information and the notes related thereto, incorporated by reference in this Prospectus (see section 15.2).

The following table shows the actual capitalisation and indebtedness as per 30 September 2018 of The Company in first column. The numbers for the Company as of 30 September 2018 are unaudited and have been derived from the unaudited interim financial statements for the nine months ended 30 September 2018. The adjustments necessary to present the capitalisation and indebtedness after considering the material events are described in section 8.2.1 below are included in the second column. The capitalisation and indebtedness on a pro forma basis, as of 30 September 2018, after taking into account adjustments as described in section 8.2.1 is presented in the third column. The compilation of the capitalization and indebtedness table as such is unaudited.

Amounts in US$ '000 - (unaudited)	**Panoro Group 30 September 2018**	**Adjustments** *See Note 8.2.1*	**Adjusted Panoro Group 30 September 2018**
Capitalisation and indebtedness			
Current debt			
Guaranteed	-	-	-
Secured*	5,306	2,640	7,946
Unguaranteed/Unsecured	7,871	1,628	9,499
Total current debt	13,177	4,268	17,445
Non-current debt (excluding current portion of long-term debt)			
Guaranteed	-	-	-
Secured*	7,600	13,560	21,160
Unguaranteed/Unsecured	6,847	3,887	10,734
Total non-current debt	14,447	17,447	31,894
Shareholders' equity			
Share capital	331	93	424
Legal reserve	426,944	28,007	454,951
Other reserves	(407,771)	-	(407,771)
Total shareholders' equity	19,504	28,100	47,604
Total capitalisation and indebtedness	47,128	49,815	96,943

Amounts in US$ '000 - (unaudited)	**Panoro Group 30 September 2018**	**Adjustments** See Note 8.2.1	**Adjusted Panoro Group 30 September 2018**
Net indebtedness			
A. Cash	19,568	12,799	32,367
B. Cash equivalents	-	-	-
C. Trading securities	-	-	-
D. Liquidity (A+ B+C)	19,568	12,799	32,367
E. Current financial receivable	1,574	3,137	4,711
F. Current bank debt	-	-	-
G. Current portion of non-current debt	5,306	2,640	7,946
H. Other current financial debt	7,871	1,628	9,499
I. Current financial debt (F+G+H)	13,177	4,268	17,445
J. Net current financial indebtedness(I-E-D)	(7,965)	(11,668)	(19,633)
K. Non-current bank loans	-	-	-
L. Bond issued	-	-	-
M. Other-non current loans	14,447	17,447	31,894
N. Non-current financial indebtedness (K+L+M)	14,447	17,447	31,894
O. Net financial indebtedness (J+N)	6,482	5,779	12,261

***-**refer to section 8.3 for description of secured assets.

8.2.1 Material changes in capitalization and indebtedness since 30 September 2018

Since 30 September 2018 and up to the date of this Prospectus, the following significant changes in capitalization and indebtedness have occurred which have been reflected adjustments in the above table.

The above capitalisation and indebtedness table includes the following adjustments:

Successful completion of US$ 30 million equity issue

On 7 November 2018 the Company announced a successful private placement of 15,580,000 shares directed towards the 100 largest existing shareholders as registered with the VPS as of 6 November 2018, the Company's management and the members of the Board of Directors, and selected external investors who could lawfully participate in the Private Placement. The placement was done at a share price of NOK 16.10 per share, and the share capital increase represents approximately 33.29 per cent of existing outstanding shares. The gross proceeds from the private placement is NOK 250,838,000 approximating to US$ 30 million at the date of the announcement. The allocation and issue of the Placement Shares was subject to (i) all necessary corporate resolutions being made, including approval at the EGM (held on 29 November 2018), (ii) no termination of the share purchase agreement related to the acquisition of OMV Tunisia Upstream GmbH from OMV Exploration & Production GmbH, and (iii) payment being received for the New Shares.

The Private Placement of US$ 30 million is offset by issue costs of approximately US$ 1.9 million. Exchange rate of NOK 8.36 to US$ 1 has been applied to the adjustments. All figures are unaudited.

The OMV Transaction

In connection with the OMV Transaction which is expected to complete on or about 19 December 2018, the Company has consolidated assets and liabilities at its share of 60% interest in the joint arrangement.

The effect of the OMV Transaction (assumed to be completed) on the capitalisation and indebtedness is as follows:

- Trade and other receivables increased by US$ 3.1 million, whereas the liabilities increased by US$ 5.1 million;
- Increase in liabilities through the draw-down of Senior Secured Loan form Mercuria by US$ 16.2 million (net to Panoro); and
- Reduction in cash and cash equivalents as a result of the payment of consideration to OMV of US$ 34.2 million (net to Panoro) and cash acquired at date acquisition of US$ 2.7 million.

Liquidity

As of 30 September 2018, Panoro held approximately US$ 19.6 million of cash resources available as liquidity. As a consequence of the above events, the Company may have, as of the date of this prospectus, approximately US$ 36.4 million of liquidity in the form of cash and cash equivalents after taking into account the proceeds of the equity issue and payment of cash calls towards Dussafu license and general and administration expenses since 30 September 2018 but excluding the drawdown of the Senior Secure Loan from Mercuria (US$ 16.2 million) and payment of the OMV Transaction US$ 31.5 million (including cash acquired). This number excludes proceeds from the first Dussafu crude lifting.

Non-financial assets of US$ 3.2 million, non-financial liabilities in the form of contingent unfulfilled work obligations of US$ 11 million and US$ 3.6 million in relation to the asset retirement and decommissioning provision, has not been included in the table above.

Contingent and indirect indebtedness

There are no indirect or contingent indebtedness as of 30 September 2018 and to the date of this prospectus except for below:

Deferred consideration payable to DNO ASA

As per the terms of the agreement with DNO ASA, Panoro is obliged to pay a maximum of US$13.2 million of deferred consideration based on future production from Sfax Offshore Exploration Permit in Tunisia. This payment is only subject to commencement of production from Sfax Offshore Exploration Permit which is still at an exploration stage and therefore a contingency.

Uncertainties surrounding abandonment liabilities

In Brazil, termination agreements for the surrender of Coral and Cavalho Marinho licences have been signed between the JV partners and Brazilian Regulator ANP. The next steps involve various regulatory clearances before dissolution of JV operations. The Company's formal exit from its historical Brazilian business is still ongoing with slow progress towards the approval of abandonment by the Brazilian regulators. Management is working actively with the operator Petrobras to bring matters to a close and to ensure that the ongoing costs are kept to a minimum. However, the timing and eventual costs of such conclusion is uncertain at this stage.

8.3 BORROWINGS

The Company's borrowings and planned maturity profile is set out in the following table:

Lender	Interest	Balance to be repaid *US$ '000*	Repayable within one year* *US$ '000*	Repayable after one year* *US$ '000*	Potential term of repayment
Mercuria Senior Secured Loan	US$ 3-month LIBOR + 6.0% p.a., paid quarterly on drawn amounts	16,200	2,640	13,560	Up to 5 years.
BW Energy	7.5% per annum on outstanding balance, compounded annually.	12,906	5,306	7,600	No fixed term, subject to complete recovery as described below.

*The above table shows the estimated repayment of principal under the loans and accrued interest up to 30 September 2018. Interest and loan repayments of these loans are described below and are dependent on several variables such as future oil production, future oil prices and future interest rates that will determine the interest payments. As such, it is not possible to estimate interest maturity and has not been included in the table above.

8.3.1 Loan from Mercuria

Mercuria Assets Holdings (Hong Kong) Ltd ("**Mercuria**"), has provided for the acquisition a Senior Secured Loan facility of US$ 27 million ("**Senior Loan**") to the Company's 60% owned company Panoro Tunisia Production AS (the "**Buyer**"). In addition, Mercuria has also made available an additional Junior Loan facility for a further $8 million ("**Junior Loan**"), which the Buyer will retain as an option at this time. The effective borrowing for Panoro at 60% interest in the Buyer, will be US$ 16.2 million in the Senior Secured Loan facility and US$ 4.8 million in the Junior Loan facility.

Key terms of the Senior Loan and Junior Loan arrangements, respectively, are:

<u>Senior Loan terms</u>

Senior Loan Amount	US$ 27 million
Tenor	5 years
Interest	US$ 3-month LIBOR + 6.0% p.a., paid quarterly on drawn amounts
Structuring Fee	1.25% of the Loan Amount
Repayment	Quarterly amortization of a quantum to be finalized based on the Agreed Model at closing, expected to start at US$1.1 million per quarter for the first 7 quarters, followed by US$ 1.35 million per quarter over the following 3 quarters, after this US$ 1.25 million for a single quarter and US$ 1.75 million per quarter thereafter until loan is repaid.
Cash Sweep	Borrower shall apply towards early repayment of the Senior Loan by way of quarterly cash sweep, the minimum between i) 50% of its net cash flows (after operating expenses, capital expenditures, quarterly amortisation and interest payments), and ii) 100% of excess cash above US$3.5 million (the "Reserve Amount")
Ranking	Senior Secured, pari-passu with credit exposure related to the hedging instruments.
Financial covenants	See below

Security	See below
Repayment	See below

Junior Loan terms

Junior Loan Amount	Up to US$ 8 million
Tenor	6 years
Interest	US$ 3-month LIBOR + 8.0% p.a. paid in cash.
Drawdown Fee	The equivalent of 500bps applied to the Junior Loan principal amount, and payable at draw-down of loan at the subscription price of the new equity raised on the financial markets to finance the Acquisition (the "Subscription Price"). The Drawdown Fee payable is US$ 400,000 equivalent to 207,702 Panoro shares. This fee payable in Panoro shares only at Drawdown of Junior Loan facility.
Structuring Fee	The equivalent of 400bps applied to the Junior Loan principal amount, payable at closing at the Subscription Price, whether the Junior Loan is drawn or not. The Structuring Fee payable is US$ 320,000 equivalent to 166,162 Panoro shares. This fee is payable in Panoro shares on drawdown of Senior Loan facility.
Commitment Fee	A fee calculated at 40% of the Margin applicable to the Junior Loan Facility per annum on the undrawn amount of the facility for the Availability Period applicable to The Junior Loan Facility.
Availability Period	The date falling 6-month after Acquisition closing
Scheduled Maturity Date	6 years from the Closing Date
Cash Sweep	In both cases subject to minimum cash: (i) Before the full repayment of the Senior Loan, the Borrower shall apply 25% of its net cash flows (post Senior Facility debt service, including the Senior sweep) towards early repayment of the Facility by way of quarterly cash sweeps. (ii) After the full repayment of the Senior Loan, the Borrower shall apply 75% of its net cash flows towards early repayment of the Facility by way of quarterly cash sweeps.
Ranking	Secured, junior to the Senior Loan (subject to an inter-creditor agreement providing for a 180-day standstill period) but senior to all other obligations of the Borrower.
Financial covenants	See below
Security	See below
Repayment	See below

Financial Covenants

Financial covenants to be tested at the end of every 3 month period post-closing on the basis as agreed in the loan agreement:

- Field life coverage ratio: 1.50x
- Minimum cash balance of US$ 3.5 million to be maintained

- Debt service coverage ratio: between 1.15x and 1.25x subject to specifications in the loan agreement.
- Liquidity Test: Customary to the loan instrument.

Security Package and Parent Company Guarantee

Guarantee from Panoro Energy ASA, share pledge over shares in OMV Tunisia Upstream GmbH and from Panoro Tunisia Production AS, shareholder and intercompany loans (subordinated at all times), rights under hedging agreements, and the Account Management Agreement (for the Collection Account), negative pledge over the assets.

In case the guarantee placed by Panoro Energy ASA is called upon, the shareholders' agreement with Beender for the ownership on Sfax Petroleum Corporation AS provides that Sfax Petroleum Corporation AS shall indemnify Panoro Energy ASA. If Sfax Petroleum Corporation AS is unable to indemnify Panoro Energy ASA, such indemnification, pro rata to its ownership, shall be made by Beender.

Voluntary repayment

Loan may be repaid in full any time. Prepayment fees shall be applied to the prepayment as follows:

- Within 12 months of disbursement: 3.0%
- Between 12 and 24 months of disbursement: 2.0%

8.3.2 Loan from BW Energy

The Company's subsidiary Pan Petroleum Gabon BV has in place a non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of 30 September 2018, Panoro was fully drawn down on the non-recourse loan at US$ 12.5 million and had an accumulated interest of US$ 0.5 million. The non-recourse loan is repayable through Panoro's allocation of the cost oil in accordance with the Dussafu PSC, after paying for the proportionate field operating expenses. The repayment period has started after achieving production on Dussafu and will repaid from Panoro's portion of upcoming crude oil sales. During the repayment phase, Panoro will still be entitled to its share of profit oil from the Dussafu operations. The BWE loan is secured against Panoro's share of Cost Oil generated from extraction of hydrocarbons (as defined in the Dussafu Production Sharing Contract).

For the purpose of classification in the Group's statement of financial position as of 30 September 2018, the loan balance has been categorised in current portion due within one year at US$ 5.3 million and the non-current portion due after more than one year has been estimated at US$ 7.7 million. Since the repayment of the loan is linked to production and, impacted by oil prices and operating expenses, judgement has been exercised in estimation of these values. The actual repayments may therefore vary from the estimates in current and non-current portions recognised as of the date of the statement of financial position.

8.4 TREASURY AND FUNDING POLICY

The Company's operating currency is US$. For banks and financial institutions, only parties of credible standards are accepted. Any change of financial institutions (except minor issues) are approved by the Group CFO.

The Company continuously evaluates measures to strengthen its financial basis and to ensure that the Group are fully funded for its planned activities. The Group manages its capital structure and makes adjustments to it in light of changes in economic conditions.

Following the OMV Transaction, a hedging programme is being introduced for the production from the OMV concessions as per the Mercuria loan agreement, whereby approximately 600 bopd of the anticipated production of the OMV concessions, net to Panoro, is required to be hedged on a rolling basis over the period of the loan term to protect the oil price downside and ability to service debt. Other group production is anticipated to remain unhedged.

The Company's cash-reserves, of which the majority are in US$, will mostly be kept in interest-bearing accounts at the Company's bank facility providers Pareto Bank ASA.

8.5 PROPERTY, PLANT, AND EQUIPMENT

As of 30 September 2018, property, plant and equipment held by the Group, all of which are owned apart from US$ 0.1 million in the UK which are leased, are as follows:

Location	Production facilities and equipment	Fixtures, furniture and fittings	Total	Current average daily production
	US$ '000	*US$ '000*	*US$ '000*	*bopd*
Nigeria (Aje)	7,706	-	7,706	386
Gabon (Dussafu)	15,701	-	15,701	594
Tunisia	-	180	180	-
UK	-	61	61	N/A
Total	23,407	241	23,648	

The tangible properties located on licenses and concessions in Nigeria and Gabon and are held through Joint Ventures with partners.

In addition to these, from the date of the OMV Transaction completion, tangible assets of US$ 16.5 million will be consolidated which comprise of production assets (including platforms, pipelines and equipment).

Operating leases

The following table sets out the Group's future commitments of lease payments based on a standard rental period with minimum payments (i.e. fixed rental costs excluding additional lease payments calculated based on revenue) under (1) 1 year, (2) 1-5 years, (3) after 5 years, as of 30 September 2018. The lease rentals primarily relate to office premises in London which has a ten year lease period with a break clause in year five. At the end of the initial five year period the lease terms are subject to a mutual review and therefore only minimum payments up to such period are included in the table below.

US$ '000 (unaudited)	**As of 30 Sep 2018**
Minimum payment next year	1,265
Minimum payments 1-5 years	-
Minimum payments after 5 years	-

The office premises in London is sub-let from Elan Property B.V. and covers an area of approximately 2,196 square feet. The office space is purely used for office staff and related activities and contains normal office furniture, IT equipment and supplies.

The Group is also contracted through the OML 113 Joint Venture in a ten-year bare-boat charter of the FPSO vessel Front Puffin. The Group's share of lease rentals in the initial three-year contract period started from July 2016. The minimum rentals for the financial year ending 31 December 2018 is US$ 0.4 million and US$ 0.9 million up to the completion of the third anniversary from the commencement of commercial production in July 2019. After the initial three years, the lease is cancellable without penalties. The estimated rentals disclosed on this note are based on the Group's net paying interest of 16.255% in Aje Cenomanian oil development.

8.6 CURRENT OBLIGATIONS AND COMMITMENTS

Apart from capital expenditure obligations identified in section 9.8.4 "Specific Terms and Conditions of the Licenses", the Company has no current capital expenditure obligations related to its licenses and concessions. Discretionary capital spend decisions related to the continued development of current assets, especially Dussafu in Gabon (see section 9.5.6.2) and Sfax in Tunisia (see section 9.8.4.3), will determine financing needs for the foreseeable future.

8.7 GUARANTEES AND PLEDGES

The Company has provided a performance guarantee to the Brazilian directorate Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (the "**ANP**"), in terms of which the Company is liable for the commitments of Coral, Estrela do Mar, Cavalo Marinho licenses in accordance with the given concessions of the licenses. The guarantee is unlimited. The Company's subsidiary Panoro Energy do Brasil Ltda alongside its partners has entered into a termination agreement with ANP on all the licenses to conclude the relinquishment formalities on each license and as such the guarantee no longer has a significant exposure to the Company.

Under section 479A of the UK Companies Act 2006; two of the Company's indirect subsidiaries Panoro Energy Limited (Registration number: 6386242) and African Energy Equity Resources Limited (Registration number: 5724928) have availed exemption for audit of their statutory financial statements pursuant to guarantees issued by the Company to indemnify the subsidiaries of any losses towards third parties that may arise in the financial year ended 31 December 2017 in such Companies. The Company can make an annual election to support such guarantee for each financial year.

The Company issued a parent company guarantee to the State of Gabon to fulfil all obligations under the Dussafu Production Sharing Contract.

In July 2018, the Company and its jointly controlled company Panoro Tunisia Exploration AS has issued a guarantee to the Republic of Tunisia to fulfil all obligations under the Ras El Besh concession and Sfax Offshore Exploration permit in Tunisia. The guarantee is fixed to the monetary value of the fulfilment of minimum work obligations under the respective contracts which is estimated to be a maximum of US$ 16.6 million.

In July 2018, The Company has issued a performance guarantee on behalf of its jointly owned company Panoro Energy AS to fulfil the payment obligation of deferred consideration of up to US$ 13.2 million to DNO ASA once the milestones as agreed by parties are met.

There is no potential claim against these performance guarantees and all obligations meeting recognition criteria under IFRS, are already accounted for in the statement of financial position as of 30 September 2018.

In addition, in connection with the OMV Transaction, the Company has placed a parent company guarantee in favour of Mercuria Assets Holdings (Hong Kong) Ltd. to guarantee the obligations of Panoro Tunisia Production AS as borrower, please see section 8.3.1 above.

9. PRESENTATION OF THE COMPANY

9.1 INTRODUCTION

Panoro Energy ASA is an independent oil and gas exploration and production company based in London and listed on the Oslo Stock Exchange with ticker PEN. The Company holds exploration, development and production assets in Africa, namely OML 113 (Aje) offshore western Nigeria through its fully owned subsidiary Pan-Petroleum Aje Limited, the Dussafu License offshore southern Gabon through its fully owned subsidiary Pan-Petroleum Gabon B.V. and Sfax Offshore Exploration Permit and Ras El Besh Exploration Concession in Tunisia through its fully owned subsidiary Panoro Tunisia Exploration AS.

Panoro holds an 8.333% non-operated interest in the Dussafu Marin license offshore Gabon. The remaining 91.667% is owned by the operator BW Energy Gabon, a subsidiary of BW Offshore. There are five oil fields within the Dussafu Permit: Ruche, Tortue, Moubenga, Walt Whitman and Ruche North East. A plan for development of the discovered resources within the Dussafu permit was approved by the Gabonese Government and an Exclusive Exploitation Authorisation ("the Ruche area EEA"), covering an area of 850.5 km^2 and encompassing the five fields, was awarded in 2014. The first field to be developed is the Tortue field. The field came on to production in September 2018 with two horizontal wells producing oil into a leased FPSO. A second phase of development drilling is planned at Tortue in 2019. Current gross 2P reserves at Tortue are estimated to be 23.5 million barrels of oil (1.6 million barrels of oil equivalent net to Panoro). Tullow has confirmed their intent to exercise the 10% back-in right into the Dussafu license as stipulated in the production sharing contract (PSC). Tullow will be required to pay a portion of past costs and, following completion of this back-in, Panoro's interest in the Dussafu Marin license will be 7.5%.

Panoro has a 6.502% interest in OML 113 which is operated by Yinka Folawiyo Petroleum (YFP) and is located in the extreme western part of offshore Nigeria adjacent to the Benin border. The license contains the Aje field as well as a number of exploration prospects. The Aje Field was discovered in 1997 in water depths ranging from 100-1,500m. Five wells have been drilled to date on the Aje Field, all but one finding oil and gas. A Field Development Plan was approved in 2014, and the field came on production from 2 wells through a leased FPSO in May 2016. The field produces oil from the Cenomanian and Turonian oil rim and to date the field has produced about 2.7 million barrels of oil, gross. A second phase field development plan was prepared in 2017 describing development of the gas resources in the field. Future plans include additional development wells in the Cenomanian, the Turonian oil rim and the Turonian gas cap. Current gross 2P reserves are estimated to be 136 million barrels of oil equivalent (21 million barrels of oil equivalent net to Panoro).

Panoro, through its newly acquired subsidiary, Panoro Tunisia Exploration AS, holds an 87.5% participating interest in the Sfax Offshore Exploration Permit and the Ras El Besh Concession, offshore Tunisia. The Sfax Offshore Exploration Permit (containing the Ras El Besh Concession) lies in the prolific oil and gas Cretaceous and Eocene carbonate platforms of the Pelagian Basin offshore Tunisia. In the vicinity of the Permit area are numerous existing producing fields with infrastructure and spare capacity in pipelines and facilities. There are three oil discoveries on the permit, Salloum, Ras El Besh, and Jawahra, with gross recoverable oil estimated by the former operator of 20 million barrels. In addition to these discoveries there is considerable exploration potential in the Permit, and the previous operator's P50 unrisked gross estimate of prospective resources was 250 million barrels of oil.

The Company may, subject to a range of factors, many of which are beyond the control of the Company, seek to acquire other licenses. In the view of the Company, this is part of future strategies of the Company which is not prudent to discuss in the prospectus.

9.2 INCORPORATION, REGISTERED OFFICE AND REGISTRATION NUMBER

Panoro's legal and commercial name is Panoro Energy ASA. The Company was incorporated on 28 April 2009 under the name Startup 387 09 AS and was later renamed to New Brazil Holding ASA. In connection with the Merger and the listing of the Company's Shares on Oslo Børs, the Company was renamed to Panoro Energy ASA on 1 June 2010. The Company is a Norwegian Public Limited Company organised under Norwegian law, including the Norwegian Public Companies' Act. Panoro's registered organization number is 994 051 067. The Company's share are tradable on the Oslo Stock Exchange under the ticker code "PEN".

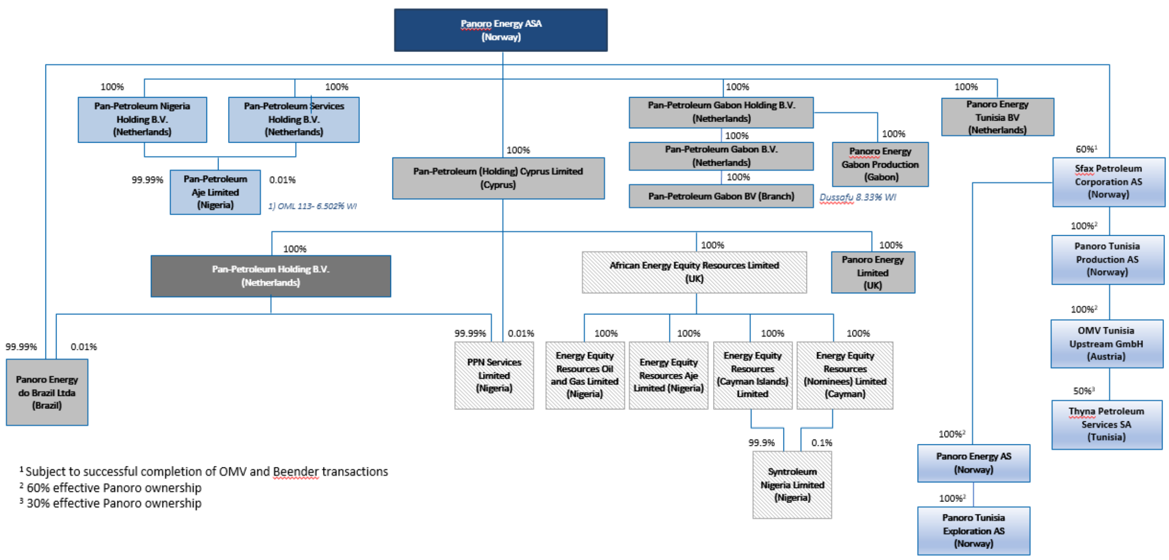
As of the date of this Prospectus, Panoro's registered share capital is NOK 3,119,380 divided into 62,387,600 Shares each with a nominal value of NOK 0.05. All the Shares are authorised and fully paid and are freely transferrable.

The Company has one class of shares, each Share carrying equal voting rights at general meetings. The Company's articles of association does not provide for limitations on the transferability or ownership of Shares.

Panoro's registered office is at c/o Michelet & Co Advokatfirma AS, Grundingen 3, 0250 Oslo, Norway. The Company's telephone number is + 44 203 405 1060. The Company has a correspondence office in London with address 78 Brook Street, London, W1K 5EF, United Kingdom.

9.3 LEGAL STRUCTURE

Following completion of the OMV Transaction, the legal structure of Panoro Energy will be as set out below:



The issuer principally acts as a holding company with activities in place to manage the group and provide funding to the material subsidiaries. Besides providing funding to subsidiaries the main activities of the Company include maintenance of corporate directorate, governance and shareholder interface, meeting listing requirements and compliance.

The Group consists of Panoro Energy ASA, which is the parent company and the following:

<u>Subsidiaries</u>

- Panoro Energy do Brasil Ltda
- Panoro Energy Limited
- African Energy Equity Resources Limited
- Pan-Petroleum (Holding) Cyprus Limited
- Pan-Petroleum Holding B.V.
- Pan-Petroleum Gabon Holding B.V.
- Pan-Petroleum Gabon B.V.
- Pan-Petroleum Nigeria Holding B.V.
- Pan-Petroleum Services Holding B.V.
- Panoro Energy Tunisia B.V.

- Pan-Petroleum Aje Limited (“**PPAL**”)
- Energy Equity Resources Aje Limited
- Energy Equity Resources Oil and Gas Limited
- Syntroleum Nigeria Limited
- PPN Services Limited
- Energy Equity Resources (Cayman Islands) Limited
- Energy Equity Resources (Nominees) Limited
- Panoro Energy Gabon Production SA

Jointly controlled companies
- Sfax Petroleum Corporation AS
- Panoro Energy AS
- Panoro Tunisia Exploration AS
- Panoro Tunisia Production AS
- *OMV Tunisia Upstream GmbH (following completion of OMV Transaction)

Joint operating company
- *Thyna Petroleum Services SA (acquired following completion OMV Transaction)

Material subsidiaries and jointly controlled companies

Company	Country of incorporation	Field of activity	Effective holding
Pan-Petroleum Gabon Holding B.V.	Netherlands	Holding company of the Group’s Gabon operations.	100%
Pan-Petroleum Nigeria Holding B.V.	Netherlands	Holding company of the Group’s Nigerian operations.	99.99%
Sfax Petroleum Corporation AS	Norway	Holding company of the Group’s Tunisian operations	60%
OMV Tunisia Upstream GmbH	Austria	Holding company of the Group’s Tunisian operations	60%

9.4 BRIEF HISTORY AND DEVELOPMENT

The below table briefly outlines the most important events and developments throughout the history of Panoro Energy ASA:

Date	Important material events
January 2005	The two companies Northern Oil ASA and NaturGass (USA) AS merged and changed its name to Norse Energy Corp. ASA (“**Norse Energy**”)
July 2005	Norse Energy was listed on the Oslo Stock Exchange under the ticker symbol “NEC”
April 2010	The Company and Pan-Petroleum Holding AS agreed a merger with the aim of creating a significant E&P company with assets and organisations complementary of each other
June 2010	Completion of de-merger from Norse Energy Corporation and Panoro Energy ASA inherits Brazilian business. The demerger and separation of the two business areas were assumed to optimise the capital structure and provide significant growth potential in the respective markets. Through the demerger, Panoro Energy acquired, among other things, 70% of the shares in Norse Energy do Brasil S.A ("**NEdB**")
June 2010	Panoro Energy ASA finalise merger with Pan-Petroleum Holding AS and through the acquisition seizes control of the remaining 30% of the shares in NedB

Date	Important material events
November 2010	Panoro completes successful US$ 140 million bond issue
November 2010	Completes sale of Ajapa field in Nigeria for US$ 30 million
January 2011	Farm-out of Brazilian Round-9 licenses completed with three exploration wells carried and US$ 15 million past costs reimbursed to Panoro.
February 2011	Completes NOK 550 million private placement
April to August 2011	Oil bearing discoveries in Gabon on Dussafu block on Ruche well and side-track
May 2013	Announcement of divestment of Brazilian subsidiary for US$ 140 million and contingent earn-out which included Panoro's 10% interest in Manati
July 2013	The Company completed the sale of its 20% interest in the MKB permit to Societe Nationale des Petroles du Congo ("**SNPC**") the operator of the MKB Permit in the Republic of Congo. The transaction was completed in July 2013
February 2014	Oil bearing discovery in Gabon on Dussafu block on Tortue well
March 2014	All the Joint Venture partners decided to relinquish the remaining BS-3 blocks, Estrela do Mar and Cavalo Marinho in Brazil. Divestment of Brazilian subsidiary completed following approval by the Brazilian regulatory authority ANP
March 2014	The government of Nigeria approved of a Field Development Plan ("FDP") for Aje
July 2014	Declaration of Commerciality and Award of Exclusive Exploitation Authorisation for Dussafu Block offshore Gabon
October 2014	Panoro and Joint Venture Partners make Final Investment Decision on OML 113 license (Aje field) in Nigeria
October 2014	Approval of development and production plan of Ruche discoveries, offshore Gabon
September 2015 – November 2015	Completion of production well operations on Aje field in Nigeria
February 2016	Completion of NOK 70 million Private Placement
April 2016	Completion of NOK 10 million subsequent offering
May 2016	First oil production from the Aje field, offshore Lagos
May 2016	Completion of reverse split of the Company's shares in the ration 10:1
April 2017	Completion of the sale of a 25% working interest in the Dussafu PSC for cash consideration of US$ 12 million and a capped limited recourse development loan to fund expenditures through first oil production
August 2017	Completion of share buy-back of 1,000,000 shares
January 2018	Approval of Field Development Plan ("FDP") for the Tortue oil field, part of the Dussafu asset, by the Gabonese regulator
January 2018	Drilling commenced on the DTM-2H production well on the Tortue oil field, located offshore Gabon and part of the Dussafu Marin Production Sharing Contract
February 2018	Announcement of updated oil reserves of the Tortue oil field, located offshore Gabon and part of the Dussafu Production Sharing Contract
April 2018	Successful drilling and completion of the first development well, DTM-2H, located in the Tortue field, within the Dussafu PSC, offshore Gabon
April 2018	Release of 2017 Annual Statement of Reserves incorporating the preliminary results of an updated Competent Persons Report (the "CPR") on its Aje field

Date	Important material events
	located in OML 113, offshore western Nigeria
May 2018	Successful drilling of the DTM-3 appraisal well located at the Tortue field, within the Dussafu License, offshore Gabon
June 2018	Successful drilling and completion of the second development well, DTM-3H, located in the Tortue field, within the Dussafu PSC, offshore Gabon
July 2018	Completion of the acquisition of DNO Tunisia AS
August 2018	Completion of NOK 67.3 million Private Placement of 4,250,219 and allotment and sale of 1,000,000 treasury shares
August 2018	Announcement of oil discovery in the Ruche North East Marin-1 well drilled in the Dussafu Marin PSC, offshore Gabon
September 2018	Achieved first oil production from the Tortue field and concluded the successful drilling and completion of the Ruche North East (DRNEM-1) appraisal well located within the Dussafu PSC, offshore Gabon

At present, the Company is focused on developing its Tunisian portfolio and phase 2 of the Tortue field in Gabon. Furthermore, following the licence renewal for OML 113 in Nigeria the Company is diligently working with its joint-venture partners on the next phase of activity at the field based around the submitted Turonian gas FDP and possible exploitation of the Turonian oil rim.

9.5 BUSINESS OVERVIEW

The Company has a balanced portfolio of quality assets in Africa which provides a strong platform for further growth. This section describes the assets in detail with their reserves and resources.

9.5.1 Reserves and resources

Panoro'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/WPC/ AAPG/SPEE) as issued in March 2007. The system is a recognized resource classification system in accordance to Oslo Børs' Circular 9/2009 "Listing and disclosure requirements for oil and natural gas companies". The maturity within each class is also described to help guide classification of a given asset. Further details of the SPE-PRMS can be found at: http://www.spe.org/industry/reserves/prms.php.

The Company's reserves have, on request by the Company, been verified by its certification agents; Gaffney, Cline & Associates, AGR TRACS International Ltd. and Netherland, Sewell & Associates, Inc. See section 16, "Statement regarding expert opinions" for more information about the Company's certification agents. The annual statement of reserves for the financial year ended 31 December 2017 can be found at http://mb.cision.com/Public/399/2509623/acdbbf219a5e5f69.pdf. The yearly updates of the annual statement of reserves can be found through http://www.panoroenergy.com/investors/annual-statement-of-reserves/.

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.

1P reserves are proven reserves that will be recovered with 90% probability. 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 reserves are proved (1P as above) plus probable reserves, which will be recovered with 50% probability. Probable reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proven Reserves (1P).

3P reserves are proven, probable, and possible volumes that will be recovered with 10% probability.

Contingent resources are the volumes of hydrocarbons expected to be produced from known accumulations: in the planning phase, where development is likely, where development is unlikely with present basis assumptions, and under evaluation. Contingent resources are reported as 1C, 2C, and 3C, reflecting similar probabilities as reserves

Reserves portfolio

As per 31 December 2017, Panoro had two assets with reserves and contingent resources, OML 113 and the Dussafu Permit. A description of these assets with status as of year-end 2017 is included below. The Annual Statement of Reserves at 31 December 2017 published in April 2018 was based on preliminary numbers for Aje. The CPR was subsequently finalised by AGR TRACS International and the table below represent the updated reserves and resources position.

As of 31 Dec 2017	Interest	1P (Low Estimate)				2P (Base Estimate)				3P (High Estimate)			
	%	Liquids MMbbl	Gas Bcf	Total MMboe	Net MMboe	Liquids MMbbl	Gas Bcf	Total MMboe	Net MMboe	Liquids MMbbl	Gas Bcf	Total MMboe	Net MMboe
On Production													
Aje Field Oil	12.1913	1.66	-	1.66	0.20	2.02	-	2.02	0.25	2.31	-	2.31	0.28
Total		**1.66**	**-**	**1.66**	**0.20**	**2.02**	**-**	**2.02**	**0.25**	**2.31**	**-**	**2.31**	**0.28**
Approved for Development													
Tortue Field	8.333	15.90	-	15.90	1.07	23.50	-	23.50	1.55	31.40	-	31.40	1.75
Total		**15.90**	**-**	**15.90**	**1.07**	**23.50**	**-**	**23.50**	**1.55**	**31.40**	**-**	**31.40**	**1.75**
Justified for Development													
Aje Field Oil	12.1913	0.50	-	0.50	0.07	0.94	-	0.94	0.14	1.76	-	1.76	0.26
Aje Field Cond.	12.1913	10.32	-	10.32	1.58	17.41	-	17.41	2.73	27.87	-	27.87	4.11
Aje Field LPG	12.1913	20.11	-	20.11	3.14	33.86	-	33.86	5.38	54.39	-	54.39	7.79
Aje Field Gas	12.1913	-	292.70	48.78	7.62	-	492.80	82.13	13.12	-	791.90	131.98	18.90
Total		**30.93**	**292.70**	**79.71**	**12.41**	**52.21**	**492.80**	**134.34**	**21.37**	**84.02**	**791.90**	**216.00**	**31.06**
Totals													
Total Reserves		**48.49**	**292.7**	**97.27**	**13.68**	**77.73**	**492.80**	**159.86**	**23.17**	**117.73**	**791.90**	**249.71**	**33.09**

During the period from 1 January 2018 until 31 October 2018, the total amount of oil produced from the Tortue field amounted to 0.524 MMbbl gross.

During the period from 1st January 2018 until 31st October 2018, the total amount of oil produced from the Aje field amounted to 0.892 MMbbl gross.

The reserves associated with the Tunisian assets as of 30 June 2018 are shown in Table 1 in section 9.5.2.2 below.

Contingent resources

Panoro's net contingent resources are from two assets as set out in the table below:

Asset	**2C MMBOE as of 31 December 2017**
Aje Field (OML 113)	1.1
Dussafu	1.5
Total	**2.6**

A more detailed description on the Company's key discoveries is provided in section 9.5.5.2 "OML 113 exploration and development" and 9.5.6.2 "Dussafu Development – Gabon".

Contingent resources associated with the Tunisian assets as of 30 June 2018 are shown in Table 2 in section 9.5.2.2 below.

9.5.2 Tunisia – TPS Assets (49% Working Interest) acquired through OMV Transaction

9.5.2.1 Overview of the Pelagian Basin

The TPS Assets lie within the northern portion of Gulf of Gabes which in turn forms part of the Pelagian Basin. The Pelagian Basin is primarily an offshore region of the Mediterranean, located off eastern Tunisia and north-western Libya and extending slightly into Italian and Maltese territorial waters. The region comprises large and shallow continental shelf sequences and was a stable platform during the Mesozoic and Paleogene times with dominance of shallow marine carbonates to the Southwest and grading to open marine shaly facies to the Northeast. This limit was controlled by active east-west and northwest-southeast fault systems. The Late Cretaceous is characterized by an extension forming local horst and graben structures. Subsidence and extension deposition continued during Paleocene and Eocene.

From Eocene to Oligocene ages, Alpine orogenic movements started to affect central Tunisia. At that time, differential subsidence formed the Kerkennah Arch bounded by depocenters to the northwest and southeast. During Neogene times, an inversion with active subsidence occurred in most of the area; caused by a NW-SE compressive phase well observed all over Tunisia and represented by the regional Late Miocene unconformity.

A major extensional phase characterized the late Miocene and the entire Kerkennah area was compartmentalised into relatively small faulted blocks. Cretaceous faults have been reactivated during this phase and several sets of younger Miocene faults were formed.

Stratigraphically, the Pelagian shelf is a stable carbonate platform developed on the northern margins of the Saharan platform during Cretaceous to early Tertiary times. The migration of the carbonate shelf margin in response to sea level variations through this period resulted in an intricate stratigraphic juxtaposition of lagoonal, carbonate shelf and deeper water sediments.

The Tunisian portion of the Pelagian Basin has been explored since the late sixties. The Exploration became very active after the discovery of El Bouri field (1 billion boe reserves) on the Libyan side and the Ashtart field (350 mmboe) within the Eocene El Garia nummulitic play. Continued exploration resulted in further discoveries within the El Garia and within a new wide range of reservoirs especially the Upper Cretaceous plays. The Gulf of Gabes contributes the vast majority of the Mesozoic and Cenozoic oil and gas reserves in Tunisia with most productive reservoirs lying in the Upper Cretaceous-Eocene levels.

These reserves are originating from two major intervals: Late Cenomanian - Early Turonian Bahloul black shales and Ypresian Bou Dabbous argillaceous limestones and marls source rocks. The Bahloul Formation has Type II kerogen and good generation capacity although often only thinly developed. The Bahloul is established to be the source rock for the immediately overlying and therefore ideally positioned Upper Cretaceous reservoirs. The Ypresian Bou Dabbous source rock comprises a series of marls and limestones which consist of Type II amorphous material with excellent oil-prone and associated wet gas potential. This system is prolific and accounts for the majority of fields in the Pelagian Basin in both Tunisia and Libya. Oil expelled from Bou Dabbous source rock migrated up-dip along intra-formational pathways and was hosted in the lateral equivalent nummulite banks of the Ypresian El Garia reservoir

Traps for known accumulations include fault blocks, low-amplitude anticlines, high-amplitude anticlines associated with reverse faults, wrench fault structures, and stratigraphic traps. Geological and geophysical evidence points to the existence of positive-relief paleo-structures since the Albian times. The Turonian NE-SW rift system developed in the Pelagian platform, causing horsts and tilted blocks to form. Old structures were dissected by the NW-SE faults producing faulted anticlines in the deep section and fault-bend "drape" fold features in the overlying sediments. Many traps also invoke a lateral stratigraphic element within the reservoir section. Within the northern part of Gulf of Gabes, facies belts from the proximal shelf margin out to the open marine environment persist within the prospective intervals, from the Upper Cretaceous to Lower Tertiary. Facies-belt transition zones can produce a lateral "porosity pinchout" which can form an effective lateral seal. This stratigraphic trapping component has been proven at the

Reineche level in the Chergui gas field lying immediately east of the TPS Assets and at the El Garia level in the Ashtart and Hasdrubal Shell operated fields, both located further offshore to the southeast.

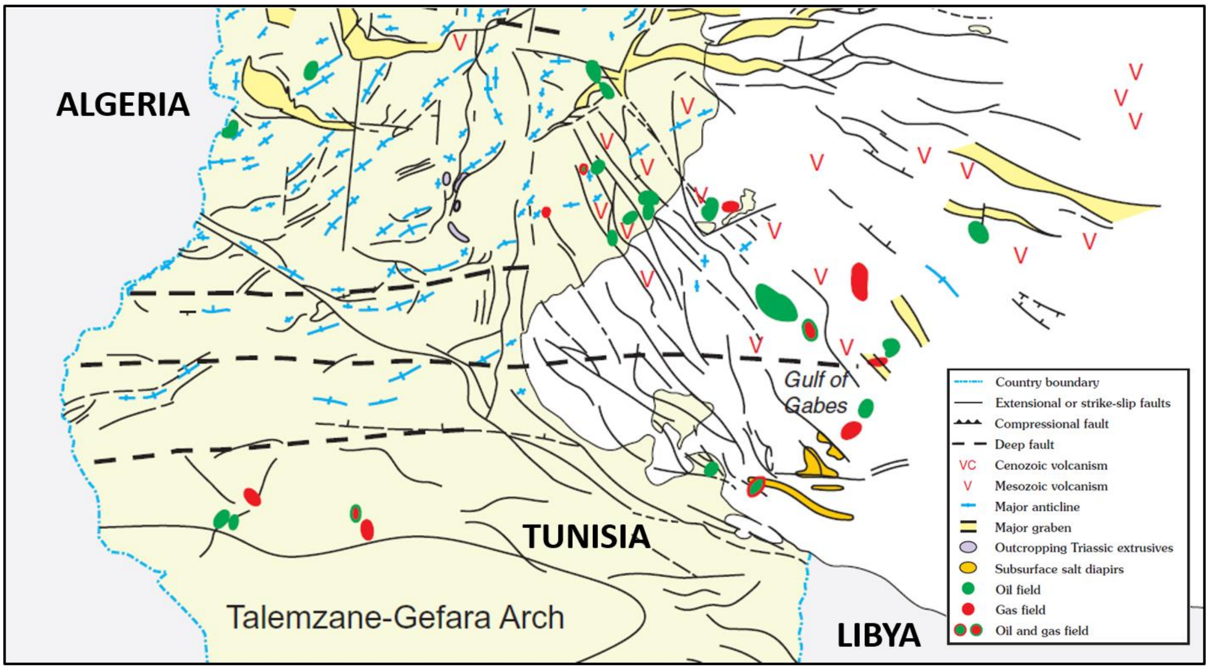


Figure 1: Oil and Gas Fields in the Gulf of Gabes/Pelagian Basin with major faults and anticlines

9.5.2.2 TPS Assets - Tunisia

Overview and background

The TPS Assets comprise five oil field concessions in the region of the city of Sfax, onshore and shallow water offshore Tunisia. The concessions are Cercina, Cercina Sud, Rhemoura, El Ain/Gremda and El Hajeb/Guebiba.

The fields were discovered by British Gas and Houston Oil and Minerals in the 1980's and early 1990's. Production started at the Guebiba field in 1981 and reached a peak of around 10,000 barrels of oil per day in 2009 with a total of 19 producing wells. British Gas sold their interest to Preussag Energy in 1997 and OMV acquired the TPS assets from Preussag in 2003. The TPS fields currently produce around 4,000 barrels of oil per day and are estimated to contribute approximately 9% of Tunisia's total oil production. Up to the end of June 2018 the TPS fields had produced a total of 54.1 million barrels of oil. The production at present is stable at around 4,000 barrels of oil per day. The independent CPR prepared by CGA indicates that production decline rate is around 2.5% per year and the fields remain economic up until the year 2033 (see Appendix 6).

OMV owns a 49% interest in the fields and a 50% interest in the TPS operating company. The remaining interests are held by the Tunisian State Oil Company ETAP.

The TPS Assets lie along the major structural and stratigraphic trends responsible for oil production in this part of Tunisia and located inside the play fairways for five of the main Cretaceous and Tertiary targets (Bireno, Douleb, Abiod, El Garia and Reineche). These plays are part of two major petroleum systems: Eocene and Upper Cretaceous. Both petroleum systems contain reservoir, source rock and seal.

Around 50 wells have been drilled in the TPS fields to date, whilst some of these wells have been abandoned, 14 remain on production with 5 wells currently shut-in awaiting workovers or reactivation. Two wells are used for disposal of produced water.

Production facilities consist of the various wellhead installations, connected via intra-field pipelines to processing, storage and transportation systems. Crude is transported to a storage and export terminal about 70 km south of the Assets at La Skhira.

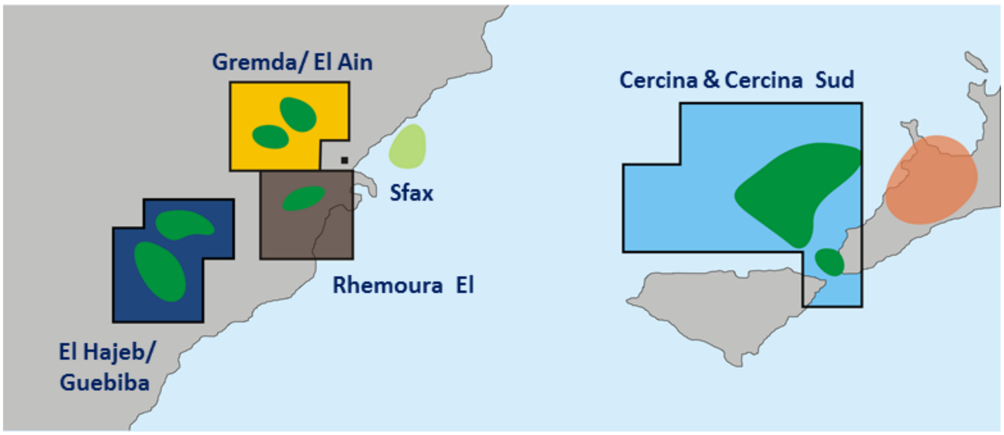


Figure 2: TPS Assets Map

Geological description

Guebiba and El Hajeb Fields

Rifting and synsedimentary faulting in the Upper Cretaceous have the main impact on the Bireno and Douleb reservoir deposition and trap shaping. The faults are mainly extensional with some indication of dextral strike-slip component. The structure of the Guebiba and El Hajeb field was formed by a combination of older compressional and younger extensional movements creating a faulted and fault limited anticline structure. The structure is compartmentalised by a predominantly NNW-SSE trending fault system with the throw of boundary faults varying between 430 to 540m on the western part and between 270 to 460m on the eastern part. Fault throw within the field varies between 10 and 40m. Guebiba is producing from Douleb and Bireno members.

The Douleb member consists of oolithic grainstone to wackestone, pelloidal, fossil debris. Oolithic and oo-bioclastic facies offer the best reservoir potential (porosity up to 25%). Deposition of the ooidal limestone took place in an agitated shallow marine environment, ranging from subtidal to intertidal and restricted lagoonal. The bioclastic limestones were deposited in a deeper depositional environment. Porosity is dominated by intraparticle porosity - parts of the ooidal grainstones, show a lack of cementation and display excellent poro-perm properties. In the Guebiba structure, the best porosities are encountered at the higher parts of the structure. This implies a preexisting relief favourable for the development of a range of porosities. Exposure to currents or a more sheltered position may explain the differences.

The Bireno member consists of wackestone to packstones, intercalated bioclastic rudstones, presence of stylolites and in the lower part, some dolomites and tight anhydrite beds. The Bireno displays intercrystalline matrix microporosity, microvuggy porosity, some intergranular and intraparticle porosity and some open fractures (porosity up to 23%). The depositional environment is shallow marine, sub- to supratidal and is divided into the four units, the UPF (Upper Peritidal Facies), the USM (Upper Shelf Margin): transitional, shallow marine, which constitutes the main reservoir, LPF (Lower Peritidal Facies) and LSM (Lower Shelf Margin).

Cercina Field

Cercina is a structurally complex and compartmentalized field. Extensional and compressional tectonics along with dextral shearing are reflected in the fault configuration of the area. The three main recognised fault groups at Reineche reservoir level are: NE-SW striking normal faults, with indicators of inversion (pre-tertiary and perpendicular to the regional compression direction), WNW-ESE Striking Faults which are normal faults with some dextral strike-slip component (consistent with the regional compression direction) and curved NW-SE normal listric faults. Compartmentalisation impacts on connected volumes and recovery factor (RF), resulting in significant non-connected volumes. Undrilled compartments offer potential upside for future field opportunities (especially in the centre and SE areas of the structure).

The Lower Reineche is the main reservoir and is interpreted to have been deposited in a high energy carbonate bank shoal setting. The Upper Reineche was most probably deposited in a lagoon environment with low energy. Latest studies demonstrate the presence of a paleo high in the Cercina area that acted as a carbonate bank separating a paleo low depression to the southwest (back bank) from an open marine slope setting to the northeast. The unit has a thickness of 10 to 12m and consists of clean and chalky carbonates with large flat B-form partially broken and nummulithoclastics characterised by interparticular and inter-crystalline porosity within a micritic or partly dolomitic matrix.

The Reineche Nummulitic limestone forms the reservoir component of the Reineche Member, having produced oil and gas in Cercina and Chergui fields. The Eocene Reineche Formation is subdivided from bottom to top into four units: the Lower Reineche Argillaceous Limestone unit (generally tight and considered to be non-reservoir), the Lower Reineche (forms the main reservoir), the Middle Reineche (tight, non-reservoir) and the Upper Reineche limestones. The Lower Reineche is the main reservoir with a thickness of 10 to 12m. Average porosity is between 17% and 21% and average permeability between 0.01 and 60mD. The reservoir appears to be fractured which enhances production considerably in the two best wells of the field (Cer-2 & Cer-3).

Rhemoura, El Ain and Gremda Fields

The structures are faulted and fault bounded NW-SE anticlines compartmentalised by normal faults. The throw is about by 10m. Gremda is compartmentalised from the El Ain structure by a NW-SE trending normal sealing fault and the Rhemoura field is characterised by a complex tectonic history. Whilst there is significant remaining potential in these fields, further structural work is required.

TPS Assets Production History

Guebiba

In 1981, production from the Douleb started with Gue-01, followed by Gue-02 (1998), Gue-05 (2004), and Gue-14 (2015). In 2005, water injection was initiated in the Douleb. In 2002, production from the Bireno started with Gue-3/4, followed by Gue-9 (2005), Gue-5A/10A (2007), and Gue-12 (2015). The suspended well Gue-10A is a side-track candidate to be completed as a Bireno producer with the possibility to commingle with the Douleb. At end 2016, Gue-14 was re-completed successfully as a commingled producer (Bireno + Douleb).

The TPS production strategy is focused on primary depletion, and secondary recovery by means of water-flooding. A recent success was achieved by commingling the Bireno and Douleb reservoirs in Guebiba after carrying out a long term production test. TPS has extensive experience in running and operating ESPs. The ESP downhole gauges are used for Artificial Lift performance and reservoir monitoring. Production System Optimisation workshops are held on a regular basis. Artificial Lift design, re-perforations, acid stimulation jobs etc. are captured in opportunity registers, planned and executed by TPS. The Guebiba field has stable production with good water handling capability.

Up to end June 2018, Guebiba and El Hajeb has produced a total of 21.3 million barrels of oil. Remaining best-estimate gross 2P reserves for Guebiba and El Hajeb are 8.6 million barrels.

Cercina

11 wells have been drilled at Cercina in the period 1991-1993. An initial production rate ~3,500 bopd was achieved from these wells. A further 3 wells (Cer-13/STH1A/15) were drilled in 2002-03. The wells commingle both the Upper and Lower Reineche layers in the West whilst the eastern wells produce from Lower Reineche only due to a pinch out of upper layer. Current production is ~2,000 bopd following the successful stimulation of Cer-STH1A.

Up to end June 2018, Cercina has produced a total of 16 million barrels of oil. Remaining best-estimate gross 2P gross reserves for Cercina are 7.7 million barrels.

Rhemoura

In 1993, production started from Rhe-01A (Douleb + Bireno commingled). PLTs were run on a regular basis (1993-95). Rhe-04 was drilled in 1993 and completed in the Bireno. In 2011, Rhe-01A was side-tracked to Rhe-01ASTG where RFTs confirmed strong aquifer support. The well was completed as a commingled producer on natural flow and regular PLTs were conducted in 2011-12. In 2012, artificial lift (ESP) was run and is a proven concept.

Up to end June 2018, Rhemoura has produced a total of 6.6 million barrels of oil. Remaining best-estimate gross 2P reserves for Rhemoura are 0.7 million barrels.

Gremda / El Ain

In 1982, the El Ain field was discovered by Gremda West 1. Shortly after the start-up of El Ain-01 in 1989, peak production of ~2,500 bopd was reached from the Bireno. In December 1992, production started from Gremda, however the field was abandoned after experiencing steep decline and a cumulative production of 61,000 bbl. El Ain-01 and El Ain-03SD are both currently suspended. The TPS partners are committed to improving production from the licence by securing and bringing El Ain-01 and El Ain-03SD back on-stream, running artificial lift in both wells (ESP) and extending the production licence.

Up to end June 2018, El Ain had produced a total of 10 million barrels of oil. Remaining best-estimate gross 2P reserves for El Ain are 2.1 million barrels.

TPS facilities

Of the 5 TPS fields, Rhemoura and El Ain fields are located in the highly populated areas of the city Sfax, whilst Guebiba and El Hajeb are in amidst olive groves and Cercina is a shallow offshore field. Two oils of different qualities are produced from the TPS fields. Oil from El Ain is light (39 deg API) and sold as Zarzatine blend, while the other fields produce a slightly heavier (31-33 deg API) crude. These two types are delivered to CFTP (Compagnie Franco Tunisienne des Petroles) and transported to TRAPSA (Compagnie Des Transports Par pipelines au Sahara), but stored separately. Crudes from El Ain, Rhemoura and the Bireno reservoir at Guebiba are sour, with hydrogen sulphide concentrations of several thousands of ppm. The TPS facilities are designed to handle this.

The Cercina field is located offshore near the Kerkennah Islands (20 km from shore) in a water depth of 3-5m. Cercina has seven oil producers, all activated with ESPs. All Cercina wells have surface wellheads and each wellhead is located on a small single-wellhead platform. The Delta platform hosts the main processing equipment such as separator skids, flare scrubbers, interconnecting piping, flaring facilities and the control room. The platform has space constraints due to its shape and existing installed equipment. Wells are linked through 4" and 2" flowlines to the Delta platform. Produced fluids are pumped to the Rhemoura site via 6", 35km oil/water pipeline. Cercina and Rhemoura fluids are commingled at the Rhemoura facility and transported to the Tank Battery through an 8"x12" concentric pipeline (14 km). The Cercina platform is powered by 3 generators which provide power for running the ESPs, export pumps and other utilities.

The Guebiba station is located amidst olive groves, 15 km south west of Sfax. The station processes fluids from Guebiba and the nearby El Hajeb field. It has four first stage separators, two dedicated for wells producing sour oil from the Bireno reservoir, one for wells producing from the Douleb reservoir and one for the El Hajeb wells. TPS recently added a second stage separation unit.

Fluids from all the TPS fields are gathered at the Tank Battery, where final processing takes place for Cercina, Rhemoura and El Ain produced volumes. Water is disposed of at the Tank Battery using two dedicated water disposal wells. Gas is partially used for power generation, with any remainder flared. After processing, the sour crude is transported via pipelines to the CFTP facility and La Shkira export terminal. El Ain crude is trucked to the CFTP facility.

TPS Assets Reserves

Gaffney, Cline & Associates ("**GCA**") has prepared a Competent Person's Report ("**CPR**") on the Reserves and Contingent Resources in the TPS Assets as at an effective date of 30th June 2018. The Reserves are shown in Table 1. The Reserves are tabulated on a gross basis and for the net interest to be acquired by Panoro. The anticipated economic life estimated by GCA in the 2P will last until 2034 for Cercina and until 2033 for El Hajeb/Guebiba, Gremda/El Ain and Rhemoura. The report can also be referred to in Appendix 6 to this document.

Concession	Gross Field			Interest to be acquired	Net to acquired interest		
	Proved	Proved + Probable	Proved + Probable + Possible		Proved	Proved + Probable	Proved + Probable + Possible
Cercina	3.4	7.7	10.0	49%	1.5	3.3	4.3
El Hajeb/Guebiba	5.4	8.6	12.1	49%	2.2	3.6	5.0
Gremda/El Ain	-	2.1	2.7	49%	-	0.9	1.2
Rhemoura	0.3	0.7	0.9	49%	0.1	0.3	0.4
Total	**9.0**	**19.0**	**25.8**		**3.8**	**8.1**	**10.9**

Table 1: Oil reserves as at 30th June 2018 (MMBbl)

The Contingent Resources are shown in Table 2.

Concession	Gross Field			Interest to be acquired	Net to acquired interest		
	1C	2C	3C		1C	2C	3C
Cercina	1.4	5.0	10.3	49%	0.6	2.1	4.4
Total	**1.4**	**5.0**	**10.3**		**0.6**	**2.1**	**4.4**

Table 2: Oil Contingent Resources as at 30th June 2018 (MMBbl)

9.5.3 Tunisia – Sfax Offshore Exploration Permit (Operator/87.5% Working Interest)

9.5.3.1 Overview of the Pelagian Basin

For a description of the Pelagian Basin were the Sfax Offshore Exploration Permit ("SOEP") is located see section 9.5.2.1.

9.5.3.2 Sfax Offshore exploration and development - Tunisia

Overview and background

The original PSC relating to the SOEP was signed on 20 July 2005 between the Tunisian national oil company ETAP, as Permit Holder, and Atlas Petroleum Exploration Worldwide Ltd. and Eurogas International Inc., collectively as Contractors. The initial licensed area was 4,036 km^2.

The Initial Exploration Period of four years started on 9 December 2005 and subsequently received a two-year Extension, plus a one-year Additional Extension. Thus, the Initial Exploration Period expired on 8 December 2012, at which point twenty percent (20%) of the initial area was relinquished. The current area of the SOEP is 3,228 km^2.

The First Renewal Period of three years duration started on 9 December 2012 and extended to 8 December 2015. On 23 December 2013, interest transfer agreements between APEX, Eurogas and DNO were approved by the Tunisian authorities. Prior to expiry of the First Renewal Period, DNO was granted a two-year extension from 9 December 2015 to 8 December 2017 and another additional extension until 8 December 2018. An application for a further three year renewal with a minimum one well exploration commitment was submitted and is currently under consideration by the authorities. Details of conditions for renewal will be known once the renewal is approved.

On 30 July 2018, Panoro Energy ASA acquired DNO Tunisia AS which has since changed its corporate name to Panoro Tunisia Exploration AS. The latter is the Operator with 87.5% working interest and 100% paying interest under the terms of an earn-out arrangement.

The SOEP is a large exploration license that covers 3,228 km^2 in the northern part of the Gulf of Gabes, southeast of the Tunisian city of Sfax. Approximately 50 km^2 of the SOEP, extends onshore, including small portions of the mainland and the southernmost portion of the Kerkennah Islands. Mostly in shallow waters, the water depth across the license ranges from 0 to 60 meters.

The SOEP lies in an established hydrocarbon province with seven active fields located immediately adjacent to the Permit, with proven reserves of over 700 MMBO and 250 BCFG and cumulative production of over 300 MMBO. Production in these neighbouring fields is from the Eocene Reineche and El Garia nummulitic limestones, and the Upper Cretaceous Douleb/Bireno shelf margin carbonates. The SOEP is favorably located adjacent to existing oil and gas production and transportation facilities with available spare capacity.

Twenty wells have been drilled within the current limits of the SOEP, with a further two wells in the area that was relinquished in 2012. Most of the wells were drilled between 1966 and 1997 with only two wells, Ras El Besh-3 (2008) and Jawhara-3 (2014) drilled more recently. Existing wells currently within the SOEP were mainly drilled on a number of pre-existing permits: Kerkennah West, Gabes Septentrional West and South Kerkennah permits. These three permits were relinquished in the early 2000's, before the formation of the SOEP.

Three oil accumulations have already been discovered within the license: Jawhara, Salloum and Ras El Besh discoveries. JAW-1, at Jawhara, tested 1,200 BOPD from Coniacian Douleb oolithic limestones and SAM-1, at Salloum, tested over 1,846 BOPD from the Turonian Bireno bioclastic limestones.

The Ras El Besh discovery is encompassed by the 68 km^2 Ras El Besh Concession (See Section 9.5.4.2), which has been carved out from the SOEP. Production rates of 2,500 barrels fluid per day (bfpd) were obtained from the carbonates of the nummulitic limestones of the Tertiary El Garia Formation in REB-2 well. Each of the on-block discoveries require further appraisal but, at present they collectively represent a discovered recoverable resource of over 20 MMbbls.

A significant number of exploration prospects/leads has been identified and characterized in the Sfax Offshore Permit supported by a large seismic data set. The combined prospective recoverable potential (P50, unrisked) is about 250 million barrels of oil (MMbbls). This prospectivity includes large independent structures with potential P50 recoverable resources of 50-70 MMbbls, allowing the possibility of both single and cluster field development scenarios.

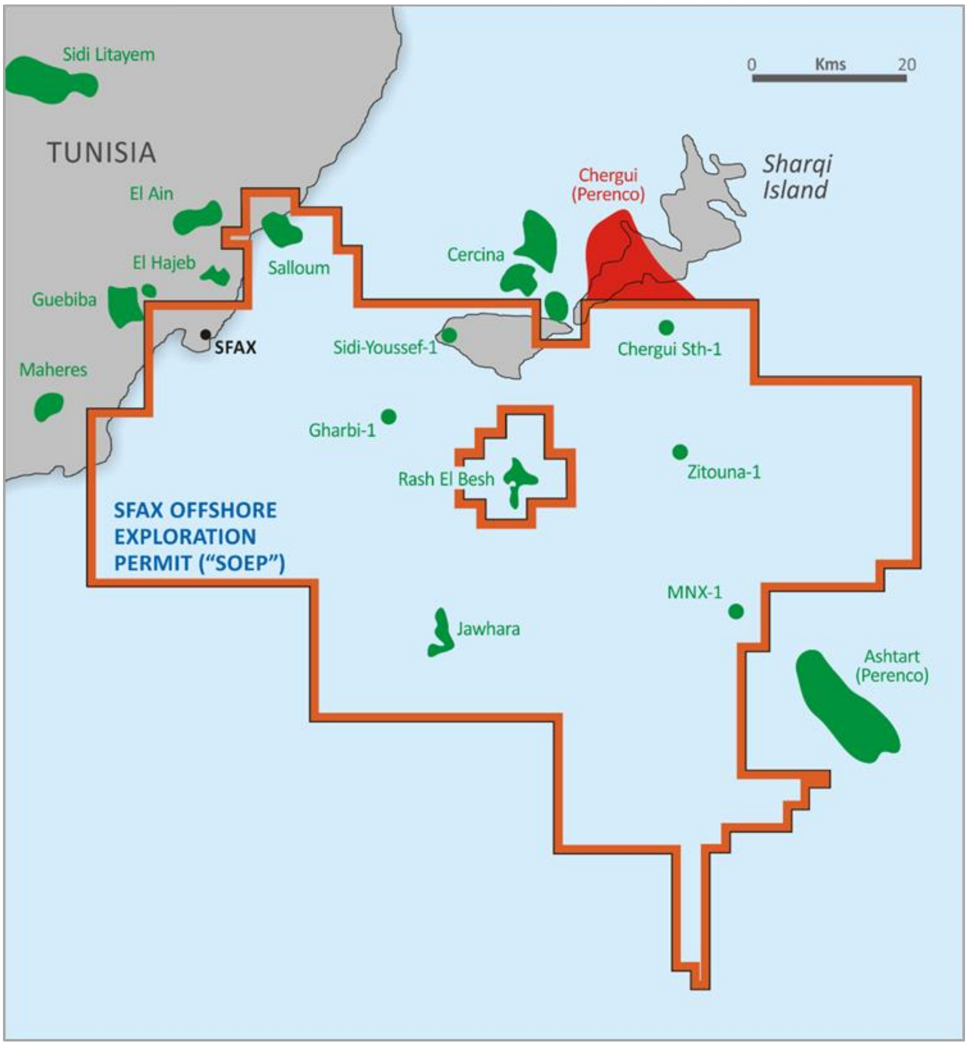


Figure 3: Sfax Offshore Exploration Permit and Ras El Besh Concession

Geological description

The area has undergone several tectonic events well known and documented in the Pelagian Basin. The Aptian-Albian compression is older than the main targeted reservoirs but it may have played a role in later structural evolution within the area. The Turonian NE-SW extension is expressed by frequent parallel normal faults which are listric and accompanied by tilted blocks.
The Late Cretaceous-Eocene compression is related to the Pyrenean event. It generated the large NE-SW feature trending high known as Kerkennah Arch, which persists to the present day. As a result of this compression, some N-S faults moved like wrench right lateral faults with a reverse vertical component, thus giving "en echelon folds" located along the faults, as demonstrated in the Jawhara area. The Kerkennah Arch is flanked to the SE an NW by two basins. Another extension took place in the Early Miocene and mainly resulted in the reactivation of NW-SE features. This extension would have been responsible for fracture generation within the El Garia reservoir which coincided with the main expulsion and migration phase from Eocene Bou Dabbous Source rock.

Sfax Offshore Exploration Permit is part of a stable carbonate platform developed and persisted from Cretaceous to early Tertiary times. This part of the Pelagian shelf is characterized by numerous transgressions and regressions that shifted carbonate shelf environments laterally in response to sea level variations. Thus lagoonal, shelf-edge and deeper water carbonate facies can often be found juxtaposed laterally and vertically. The oldest series penetrated within the northern part of Gulf of Gabes are of Lower Cretaceous age; however, the prospective section extends from Upper Cretaceous to Eocene series.

Reservoir potential is developed at numerous levels within the stratigraphic section, exclusively within carbonate lithofacies. Almost all intervals appear to have developed under ramp margin conditions that were shallow to the south-southwest and deepened towards the north-northeast. Post depositional processes (diagenesis and fracturing) have played a major role in the enhancement of reservoir effectiveness. The Eocene El Garia/Reineche and Cretaceous Bireno/Douleb intervals are regarded as the primary targets. Both can be highly effective reservoirs and are situated in close proximity to prolific source rock intervals. The Cenomanian Zebbag, and to lesser extent the Campanian-Maastrichtian Abiod, provide upside reservoir potential. The Oligocene Ketatna build-up facies is a new and evolving play concept currently under evaluation.

Three proven plays exist in Sfax Offshore Permit as follows:

- The Bireno shelf margin limestone and Douleb grainstones of Turonian-Coniacian age are a primary objective throughout much of the SOEP. Horst and tilted fault blocks set up the typical trap styles and the top seal is provided by the Upper Aleg shales and/or ultimately by the regional El Haria shales. In situ and short-distance migration from the Bahloul Formation, mature over large areas of the SOEP, provides the hydrocarbon charge. The Jawhara and Salloum discoveries within the permit, and regionally, the Rhemoura, Gremda and Guebiba fields are all examples of this play type. Depth to target ranges from 2,400 to 3,000 m.

- The Ypresian El Garia nummulitic bank is an important reservoir target in the SOEP. Both structural and stratigraphic traps are known to work with the associated Cherahil shales and tight limestones providing an excellent top seal. Hydrocarbon charge comes from the Bou Dabbous source rock. Onshore Tertiary oil often shows both Cretaceous and Tertiary signatures (e.g. the El Hajeb and El Ain fields). Thus, a possible contribution from the deeper Bahloul source rock should not be ruled out for this play. Ras El Besh, Ashtart and Hasdrubal fields are all analogues of this play type. Depth to target varies from 1,800 to 2,650 m.

- The Reineche nummulitic limestone and intra-shelf limestone equivalent are a reservoir objective over much of the SOEP. Historically, this play was not well evaluated as traditional exploration tended to focus on the Cetaceous and El Garia plays. The Reineche nummulitic limestone in particular extends onto the north-eastern part of the SOEP on trend with the Cercina and Chergui fields, which are currently producing from this reservoir. This reservoir is likely to be sourced from the Bou Dabbous which is mature in the depocentres on the flanks of the Kerkennah High. Both structural and stratigraphic traps have been observed. Depth to target range from 1,400 to 2,000 m.

The Sfax Offshore Permit is estimated to contain over 50% of the El Garia and Reineche depositional fairways offshore Tunisia and at least 20% of the Douleb/Bireno reservoir fairway. Play elements and Play types are illustrated for SOEP in Figure 4.

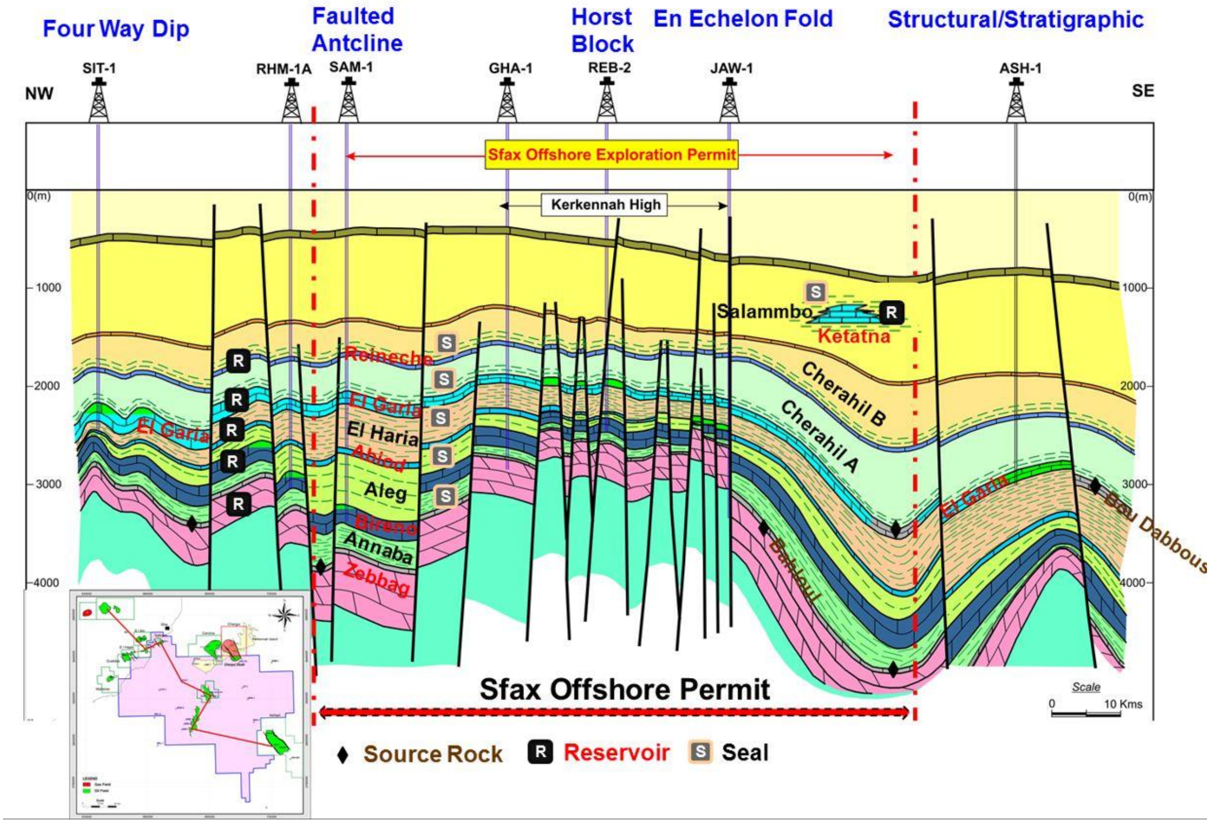


Figure 4: Play elements and types in Sfax Offshore Exploration Permit

Exploration Potential

The license is supported with an existing data base of 20 wells in addition to a substantial seismic data set of approximatively 2,145 km² of full fold 3D seismic and 8,000 km of older vintage 2D lines.
In the 1970's through the late 1990's several seismic surveys were acquired. Over 255 of 2D seismic lines representing approximately 8,100 line-km are available and were reprocessed in 2002-2003 by Gaither Petroleum (now APEX).

In 2004 APEX and its partner Eurogas, acquired a high resolution 350 km² 3D seismic survey in the central portion of the permit. This 3D survey (Sfax 3D) covers the Ras El Besh and Jawhara discoveries enabling further evaluation of their full hydrocarbon potential. In December 2005, the pre-existing Sfax Offshore Prospecting Permit was converted into the SOEP. In 2006-07, APEX and Eurogas acquired (jointly with Anadarko) a new 470 km² transition-zone 3D seismic dataset, the Kerkennah Banks survey (KB 3D). In July of 2007, APEX and Eurogas acquired a new shallow-water transition-zone 3D seismic survey over the Salloum discovery (SAM 3D) for the purposes of planning for the potential development of the Salloum discovery. The Salloum 3D survey was reprocessed in 2009. In 2010 the Sfax 3D and KB 3D surveys were reprocessed through PreSTM and merged into a contiguous survey by CGG. After taking over operatorship in 2014, DNO acquired 1,016 km² of 3D data (SFAX3D-14) in the eastern part of the permit.

The exploration portfolio consists now of more than 15 prospects, of which several are stacked multi-reservoir objectives (Tertiary and Cretaceous). They inhabit the same Cretaceous and Tertiary trends as the discovered fields. A probabilistic resource estimate has been calculated for all the identified structures. Input parameter and uncertainty ranges are based upon data and understanding from the on-block and neighboring discoveries and the numerous other control wells drilled both within and in the immediate vicinity of the SOEP. These leads and prospects were estimated to total more than 250 million barrels of gross unrisked prospective resources by the former operator DNO.

These prospects could be grouped in three geographical areas:

The Westernmost Area close to the shore and to the producing onshore fields. Apart from Salloum, it is poorly covered by 2D seismic data. The Hbara prospect lying immediately southeast of Rhemoura is attractive for further exploration activity. A shallow water transition zone seismic program is being considered to mature and de-risk this prospect and other potential nearby leads.

In the Kerkennah High Area, the prospects have been identified using the KB 3D seismic and the Sfax 3D. The prospects defined in this area of the block tend to have recoverable resources that range from 1 - 13 MMbbls. Due to the prospects' stacked nature and their close proximity to each other and to existing discoveries (Ras El Besh and Jawhara), this area is attractive for a cluster-style development concept.

Chergui South/Zitouna Area: This area lies within the Reineche nummulitic fairway which is under-explored and interpreted to hold a significant upside potential. It is on trend with the Cercina and Chergui producing Reineche fields. This area is partly covered by 3D seismic and partly covered by a coarse grid of 2D seismic data. In the 3D area, two prospect have been identified. The Sakr prospect is fully covered by 3D whilst the Zitouna prospect is partly covered by 3D. The Chergui South prospect is defined at the Reineche level and is identified using only 2D seismic lines. It has been mapped as a three-way dip closure dependent on a stratigraphic pinchout to the northeast where the nummulitic Reineche facies grades into more shale-prone basinal facies. The pinchout is defining the northeastern stratigraphic limit of the Chergui gas field. The Chergui south prospect is interpreted as an extension of Chergui field into the SOEP. While Chergui is mainly a gas field, the presence of an oil rim has been recently confirmed by the Chergui-6 well. Mean volumes of 62 bcf of gas and 12 million barrels of oil recoverable have been estimated for this prospect.

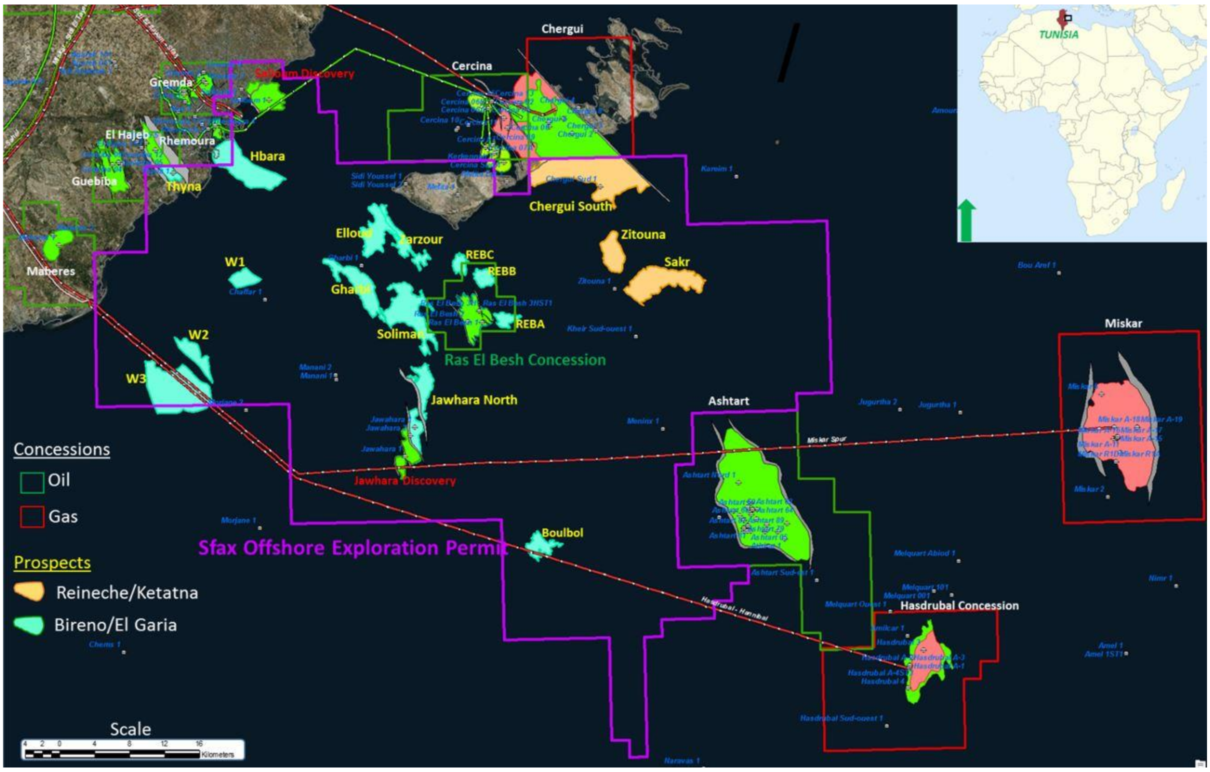


Figure 5: Sfax Offshore Exploration Permit Prospect Portfolio

Jawhara Discovery

The Jawhara prospect was initially identified and defined on the basis of 2D seismic data as a faulted anticline dissected by NNW-SSE faults. The Jawhara-1 well, drilled by Total in 1976, reached a total depth of 3,243m in the Aptian Orbata Formation. DSTs (Drill Stem Test) were performed in both the El Garia nummulitic limestones and also the Cretaceous series. While the El Garia exhibited a nummulitic facies with good reservoir characteristics, this interval tested only

water. In the Cretaceous section, the well flowed 1,200 bopd from the Douleb, 276 bopd from the Bireno and also 578 barrels of water per day (bwpd) from a deeper interval in the Bireno reservoir. Jawahara-2 and Jawhara-3 were drilled to appraise the Jawhara-1 well but failed to encounter commercial quantities of hydrocarbons.
A resource estimate for the Douleb and Bireno reservoirs was conducted by the former operator via a stochastic approach for the Jaw-1 Block and adjacent compartments. This assessment indicates a P50 recoverable resources of 11mmbo within the Jawhara structure.

Salloum Discovery

The discovery well Salloum-1 (SAM-1) was drilled by BG in 1991 to a total depth of 3,371 m MD at an offshore location NE of the city of Sfax and 2 km from the coast. Water depth is 2 meters. The Late Cretaceous Bireno Formation and the Eocene El Garia Formation were the primary objectives of Salloum-1. The El Garia was dry but oil and gas pay was found in the Bireno Formation. After acidizing the pay zone, DST-1 tested 1,848 bopd (1/2 choke) and 682 bopd (20/64 choke) of 42° API oil. DST-1 also produced 385 Mcf/d of gas with 900 ppm of H_2S. In 2007, the Salloum structure was covered by 60 km² of 3D seismic that was later reprocessed in 2009. The composite map drawn at top Bireno, interpreted from 3D and sparse 2D data, indicates a faulted anticlinal closure. The P50 unrisked recoverable resource was assessed by the former operator at 6 MMbbls of oil (although gas was tested, it is non-commercial).

Development and Resources

No Development plans have been designed yet for Jawhara and Salloum, however a conceptual plan for Salloum assumes drilling an appraisal well for a long term flow test from onshore. Plans for a work program include the well test and developing options for a possible tie-in to the infrastructure of the neighboring onshore fields of El Ain, Rhemoura and Guebiba. The appraisal well is being designed to establish a commercial hydrocarbon accumulation in order to proceed with a development, to refine the reserve base and to establish reservoir deliverability to assess commerciality.

Panoro will review and refine the resource estimates at Jawhara to formulate a plan for possible future development of the discovery. A direct tie-back to the onshore facilities is one of the options.

Other structures, if validated by new seismic acquisition and subsequent full evaluation, could be potential targets for exploration drilling. In case of discoveries, the Chergui South prospect, an extension of the Chergui field, is considered a low risk development option which can be easily tied into the Chergui field’s existing facilities. Similarly Hbara structure could be tied to Rhemoura field lying immediately to the northwest.

For the Kerkennah Area prospects, a concept for a cluster development of the fields would allow a tie-back to existing infrastructure in the area.

9.5.4 Tunisia – Ras El Besh Concession (87.5% Interest)

9.5.4.1 Overview of the Pelagian Basin

The Ras El Besh concession is part of Sfax Offshore Exploration Permit and hence part of the same geological Pelagian Basin province.

9.5.4.2 Ras El Besh development – Tunisia

Overview and background

In 2008, the Ras El Besh Concession (68 km²) was subtracted from the SOEP and granted to APEX and Eurogas for a period of 30 years starting from 5th September 2008. The concession is governed by the same PSC terms OF Sfax Offshore Permit. Ras el Besh concession was part of the Tunisian assets operated by DNO Tunisia AS. Further to the transaction concluded between Panoro Energy ASA and DNO ASA, Ras El Besh concession is now operated by Panoro Tunisia Exploration with a working interest of 87.5%.

The Ras El Besh Field is located approximately 37 km southeast of the city of Sfax and 12 km south of the southernmost tip of the Kerkennah Islands. The field is also located about 18 km south-southwest of the Cercina Field, which produces oil in the Lower Eocene Reineche and about 37km northwest of the Ashtart Field which produces oil from the Lower Eocene El Garia. Water depths with the concession vary from 12 to about 15 m.

Drilled in 1995 by ARCO, Ras El Besh 1 (REB-1) encountered good hydrocarbon shows in the El Garia but was not tested. The discovery well, REB-2, tested the El Garia and initially flowed 167 bopd and 17 bwpd. After acidizing the well tested at a rate of 612 bopd and 1,836 bwpd.

In 2004 APEX and its partner Eurogas acquired a high density/high resolution 3D seismic survey over 350 km² in the central portion of the permit covering the Ras El Besh and Jawhara discoveries in order to further evaluate their hydrocarbon potential. In 2005, APEX submitted the Ras El Besh Plan of Development (PoD) on the basis of an estimated 83 million bbls oil in place and predicted cumulative production ranging from 13 to 33 million bbls.

The well Ras El Besh-3, the first of a three well appraisal/development program was spudded in June 2008, marking the implementation of the PoD. The REB-3 well was drilled with a primary objective to establish production in the Lower Eocene (Ypresian) El Garia nummulitic limestone. A pilot hole was to be drilled to obtain geological and reservoir fluid information, and subsequently a horizontal drain hole was to be drilled to enhance production capacity and reservoir drainage.

REB-3 found El Garia low to prognosis and although interpreted to have an oil column similar to REB-2, the El Garia in REB-3 was not tested. However, the Reineche reservoir was found 6m high to prognosis, had good sidewall core and mudlog shows, and recovered oil on an MDT. A horizontal borehole section (REB-3H ST1) was completed in the Reineche interval, which was thought to be more prospective. A long horizontal section was drilled and tested, yielding 1,022 bpd of fluid (95% water and 5% oil. The REB-3 well significantly downscaled the resources of the field, putting the entire development project on hold and triggering the need for an update of the PoD.

In 2014, DNO acquired an 87.5% interest in both SOEP and the Ras El Besh Concession, while also assuming operatorship. Given that the initial 2005 PoD, designed for larger reserves, was no longer appropriate, the Contractor group and ETAP agreed in 2013 to review the original PoD. The revised calculated reserves were estimated at around 5 million bbls. The project remains on hold whilst Panoro reviews the development options for the discovery.

Geological description

The primary target of Ras El Besh Concession is the El Garia nummulitic reservoir while the overlying Reineche remains a proven target but with limited reserve potential in this Concession. Regionally, the net/gross ratios of El Garia reservoir vary from 45 to 90%. Porosity ranges from 12 to 25% with an average of 17%. Permeability varies from <1mD to 500 mD with an average of 42mD.

The REB-1 has the 2nd thickest El Garia section on the Sfax Permit. The well has 87m of gross porosity and 38m of good (18% to 24%) net porosity. The top 20m of the El Garia had good oil shows in cores including mottled oil stain, but was not tested due to high well log-derived water saturations. The REB2 well has a fairly complete El Garia section. The well has 74m of gross porosity and 50m of fair-to-good (12% to 23%) net porosity. The top 20m of the El Garia had good oil shows and solid oil stain in cores (up to 30%) and 27º API free oil was noted in fractures. In REB-3 well the El Garia interval is 80 m thick with similar reservoir properties as in REB-2.

While REB-1 and REB-2 were cored, no cores have been taken within El Garia section in Ras El Besh-3. A sedimentological study performed on the cores of REB-1 and REB-2 indicates that El Garia Formation has been deposited within a mid-ramp setting depositional setting, which appears to fit within the general depositional model developed for the Metlaoui group.
In Ras El Besh Wells, El Garia could be divided in four major zones based upon rock texture, A/B nummulite ratio and faunal/flore content.

Different types of porosity have developed in El Garia section. These porosities include intraparticle, interparticale, dissolution and fracture porosity.

Oil water contacts were determined by log interpretation. In the El-Garia, REB-2 has an OWC at 1948m.

At the top El Garia horizon, the Ras El Besh structure appears as a faulted horst block bounded by the NNW-SSE main normal faults. Minor intra field faults are also identified which could have an impact on the reservoir connectivity and field compartmentalization.

29° API oil hosted in El Garia reservoir in Ras El Besh field has been typed to Bou Dabbous Source rock. The depositional relationship of the Bou Dabbous source rock with the El Garia reservoirs potentially allows highly efficient expulsion/charge conditions. Lateral migration occurred via simple up-dip intraformational pathways by fill and spill. Cross fault leakage would take migrating hydrocarbons stratigraphically higher (Reineche and Cherahil).

Regional evaluation of Sfax Offshore Permit has revealed the existence of few prospects within the Concession of Ras El Besh both in El Garia and Reineche levels. Average P50 resources are around 2 million barrels.

Development and Resource

The initial plan of development designed by APEX assumed the drilling of two horizontal development wells (with the possibility of re-entry and side track of REB-3) and early production using low cost leased production facilities.

In the revised PoD DNO the ex-Operator, has considered different development scenarios either by building new facilities or by tying into existing facilities (Cercina, Chergui, Ashtart, Guebiba, Miskar or Hasdrubal pipelines). For all the technically retained scenarios, development costs have been generated using the Que$tor software, and project economics have been run with the corresponding production profiles. Only one scenario shows a slightly positive NPV10 for the project, which is a very simple unmanned development with a wellhead platform connected to Central Processing Facilities located at a distance of 6 kms on a Soliman/Gharbi (curreltl Cretaceous/El Garia Prospect) development.

Given the very marginal results, the DNO decision to develop REB with a connection to Soliman/Gharbi facilities would only be taken once the market conditions at the time confirm that the development can still be economically implemented.

Panoro plan is to revisit the G&G data including the static and dynamic models before the design of a viable and simple development concept.

9.5.5 Nigeria - *OML 113 Aje (12.1913% Revenue Interest)*

9.5.5.1 Overview of Benin Embayment in Nigeria

OML 113 lies within the Benin Embayment at the eastern end of the West African Transform Margin. The Benin Embayment is a passive continental margin basin extending from Ghana to the coastal regions of western Nigeria. The basin is one of the Cretaceous and younger basins lining the coast of Africa that owe their inception to the Upper Mesozoic break-up of the Gondwanaland continent and formation of the present-day Atlantic Ocean. Regional structure is dominated by southwest-northeast fracture trends and stratigraphy is largely comprised of rift, transitional and drift sequences.

The Benin Embayment has been explored since the 1960’s and the most important plays are the Turonian-Cenomanian (Abeokuta) and Albian sandstones. The Early Cretaceous rifting gave rise to the formation of both simple structural plays, as well as traps that have been modified by (often) subtle mechanisms, such as erosion or sedimentary pinch-outs. The oil found in Albian and Turonian-Cenomanian reservoirs indicate the presence of working petroleum systems throughout the Cretaceous within the Benin Embayment. The Upper Cretaceous Araromi Shale is the best potential source rock but contribution from the Ise, Abeokuta or Imo formations is likely.

One of the most significant discoveries to date in the basin is the large gas, condensate and oil Aje field, discovered in 1996 and appraised in the 2000’s, in which the Company has interests. In 2013 the potential of the Benin Embayment was further confirmed with the discovery of the large Ogo field a few kilometres to the east of Aje.

9.5.5.2 OML 113 exploration and development

Overview and background

The Company's wholly owned subsidiary PPAL holds 6.502% equity, 12.1913% revenue and 16.255% paying interests in the Aje field in OML 113 license. PPAL holds 6.502% equity, 6.502% revenue and 8.6693% paying interests in the deep water part of the OML 113 license outside of the Aje field area.

Covering and area of 840 km^2 OML 113 is operated by YFP and is located in the western part of offshore Nigeria adjacent to the Benin border. The license contains the Aje field as well as a number of exploration prospects. The Aje Field was discovered in 1996 in water depths ranging from 100-1,000m. Unlike the majority of Nigerian Fields which are productive from Tertiary age sandstones, Aje has multiple oil, gas and gas condensate reservoirs in the Turonian, Cenomanian and Albian age sandstones. Five wells have been drilled to date on the Aje Field. Aje-1 and Aje-2 tested oil and gas condensate at high rates from the Turonian and Cenomanian reservoirs and Aje-4 confirmed the productivity of these reservoirs and discovered an additional deeper Albian age reservoir. Aje-5 was drilled in 2015 as a development well to produce from the Cenomanian oil reservoir. Two sidetracks were drilled from Aje-5 in 2017. The OML 113 license has full 3D seismic coverage from surveys acquired in 1997 and 2014. On a net basis, the Aje field has produced 355 bopd since 1 January 2018 to 30 September 2018. The production level for the remaining of 2018 is not expected to be materially different than the year to date average.

In March 2014 the government of Nigeria approved of the Aje Field Development Plan and in October 2014 the Final Investment Decision ("**FID**") for the project was made. The Aje field started production in April 2016 from two wells in the Cenomanian reservoir, Aje-4 and Aje-5, with oil processed and exported from a leased FPSO, the Front Puffin. The field has continued to produce from these wells to date, with Aje-4 currently producing from the Cenomanian reservoir and Aje-5 producing from a re-completion in the oil rim of the Turonian reservoir.

A Field Development Plan for Aje gas was submitted to the Nigerian government for consideration in 2017. The gas FDP comprises four or five production wells in the Turonain tied back to existing and new infrastructure.

The exploration prospects in OML 113 are not reflected in the resource estimates and are yet to be fully evaluated. In the case that one or more of these prospects, after full evaluation, become potential targets for exploration drilling then a detailed exploration drilling plan may be proposed for approval and implementation by the OML 113 Joint Venture.

Other partners in the license are YFP (Operator), NewAge, EER and PR oil and gas (a subsidiary of MX Oil).

Geological description

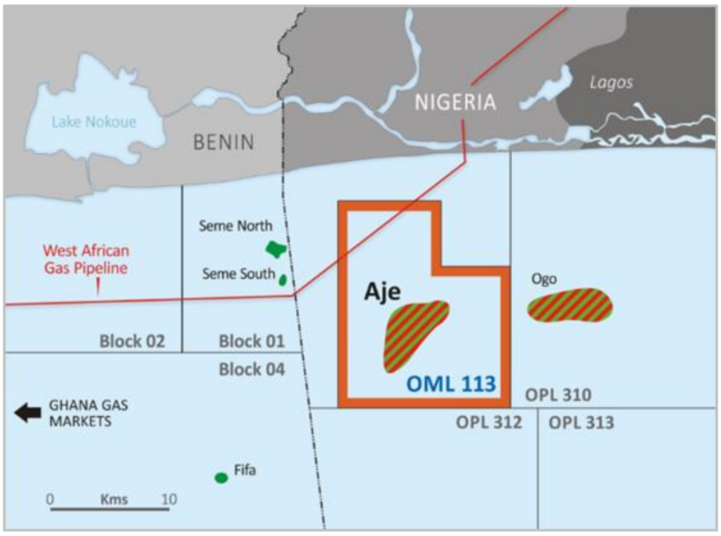


Figure 6: OML 113 Location Map

Stratigraphically, the Aje field's primary hydrocarbon-bearing zones of interest are of Turonian, Cenomanian and Albian age. The reservoir sands within these three zones are medium-to-fine-grained sandstones interbedded with silty and shaly layers. The reservoir sandstones were deposited in a narrow marine setting as part of a wave and tide dominated margin. With these conditions during sea level high stand, the sediments on the shelf were reworked, maturing the sands and breaking down the feldspars. The interval containing these three zones is circa 1,500 metres thick with the main sediment provenance being the crystalline basement to the north.

Hydrocarbon source is most likely from marine shales that correspond to the maximum flooding events of the Maastrichtian to Cenomanian times. These shales were deposited during the global anoxias of the Middle Cretaceous when widespread oxygen depletion in the water column led to extensive organic matter preservation. They are likely to be widespread in this margin and have been identified as the source of oil in western Nigeria and the nearby Seme field.

The Aje field structure is a broad four-way dip closed anticline formed by drape of Cretaceous age sediments over basement highs. The structures are controlled by basement-cored horst blocks related to rift fracture zones. Seals are provided by intra-formational shales.

The first well on Aje was the Aje-1 exploration well drilled in 1996 with a jack-up rig in shallow water. The well discovered a 69 metre gas condensate column with a 10 metre oil rim within the Turonian sandstones. Three successful drill stem tests ("**DSTs**") were conducted at different levels within the Turonian which led to substantial oil and gas flow rates of 23.1 MMcfpd gas, 887 bcpd and 2,389 barrels of oil equivalent ("**boepd**").

The following year, in 1997, the Aje-2 appraisal well was drilled approximately 400 metres east of Aje-1. The well encountered an equivalent gas column and oil rim to Aje-1 in the Turonian as well as a 14 metre oil column in the Upper Cenomanian and a 10 metre oil column in the Lower Cenomanian. Three DSTs were also carried out in Aje-2 over different levels, all resulting in highly productive flow rates of 9.8 MMcfpd gas, 450 bcpd and 3,866 boepd in the Turonian and 3,743 boepd in the Upper Cenomanian.

In 2005 Aje-3 was drilled 5 km southwest of Aje-1 in approximately 1,000 metres of water from a semi-submersible rig. The well encountered thin hydrocarbon bearing zones in low permeability Turonian and Cenomanian sands. The well was subsequently interpreted to have been drilled into a localised shale-filled channel facies which resulted in poor reservoir development at the well location.

In 2008 the Aje-4 well was drilled two kilometres to the east of Aje-2 and successfully proved the significant reserves north and east of Aje-1 and Aje-2. Gas condensate and oil columns were encountered in the Turonian whilst further oil columns were encountered in both the Upper and Lower Cenomanian. One key objective of Aje-4 was to evaluate deeper exploration targets, and the well achieved this objective successfully confirming two zones within the deeper Albian that were hydrocarbon-bearing. Within the Upper Albian massive gas condensate-bearing sands were encountered and confirmed with MDT pressure gradient measurements. Within the Lower Albian, thin-bedded sands were also logged as hydrocarbon bearing.

3D seismic data were acquired over the OML 113 license in 1997 and 2004. The seismic data have been processed using the latest 3D Pre-stack depth migration techniques. The latest seismic is of very good quality and enables robust interpretation and mapping of the Aje field and neighbouring exploration prospects.

Development, Reserves and Resources

The current phase of the Aje development is focussed on producing oil from the Cenomanian reservoir and the oil rim of the Turonian reservoir. Two wells, Aje-4 and Aje-5, are currently on production. The oil is produced to the FPSO, the Front Puffin, via subsea trees, flowlines and a riser. Produced oil is processed and stored onboard the vessel until it is evacuated to a tanker and sold. Liftings of the oil are made approximately every four months. All of the Company's production from this phase of the Aje development is produced and sold in this manner and is fully dependant on the FPSO. The field started production in May 2016, and since that date up to the end of 2017 the field has produced a total of 1.9 million barrels, gross.

A Competent Persons Report ("**CPR**") on the field was made by AGR TRACS International ("**TRACS**") in June 2018. The CPR incorporated the 2014 seismic data, the results of the Aje-5 side-track drilling, production history since field start-up and the development plan outlined in the Turonian gas FDP. The CPR estimated that, from the beginning of 2018, the two wells could produce a further 2.96 million barrels of oil gross (2P, Proved and Probable) which corresponds to 0.39 million barrels net attributable to Panoro. TRACS estimated that the field life for the 2P case would extend to 2034.

Figure 7: Aje field FPSO Front Puffin

In addition to the reserves attributed to the current development phase, future phases of development at Aje could consist of additional oil wells to produce further resources into the current Aje facilities and additional gas wells to produce gas and gas-rich liquids. Gas wells would require additional processing facilities to be constructed at the Aje site.

A Turonian Field Development Plan was submitted to the Nigerian Regulators for consideration in 2017. The plan describes a four or five well development of the Turonian gas cap and oil rim, with hydrocarbons produced into existing and new infrastructure at the Aje site. The TRACS CPR of June 2018 reviewed the development plan and classified these volumes as Justified for Development.

The Aje-5 results have meant that assessment of oil reserves in the Cenomanian have been materially reduced compared to earlier estimates. However, Turonian gas, LPG and condensate have now been re-classified from contingent status to Reserves Justified for Development as a result of the FDP submission.

TRACS has now estimated gross remaining 2P and 2C resources of 136 million barrels of oil equivalent combined could be produced from the Aje field, with gross 3P and 3C resources of 233 million barrels of oil equivalent.

At year-end 2017, 2P Reserves net to Panoro's interest related to OML 113, after deduction of royalties and other adjustments, stood at 21.6 MMBOE and 2C Contingent Resources stood at 1.1 MMBOE.

The revised annual statement of reserves for the Aje field as of 31st December 2017 is as follows:

As of 31 Dec 2017	**Interest**	**1P (Low Estimate)**				**2P (Base Estimate)**				**3P (High Estimate)**			
	%	Liquids	Gas	Total	Net	Liquids	Gas	Total	Net	Liquids	Gas	Total	Net
		MMbbl	Bcf	MMBOE	MMBOE	MMbbl	Bcf	MMBOE	MMBOE	MMbbl	Bcf	MMBOE	MMBOE
On Production													
Aje Field Oil	12.1913	1.66	-	1.66	0.2	2.02	-	2.02	0.25	2.31	-	2.31	0.28
Total		**1.66**	**-**	**1.66**	**0.2**	**2.02**	**-**	**2.02**	**0.25**	**2.31**	**-**	**2.31**	**0.28**
Justified for Development													
Aje Field Oil	12.1913	0.5	-	0.5	0.07	0.94	-	0.94	0.14	1.76	-	1.76	0.26
Aje Field Cond.	12.1913	10.32	-	10.32	1.58	17.41	-	17.41	2.73	27.87	-	27.87	4.11
Aje Field LPG	12.1913	20.11	-	20.11	3.14	33.86	-	33.86	5.38	54.39	-	54.39	7.79
Aje Field Gas	12.1913	-	292.70	48.78	7.62	-	492.80	82.13	13.12	-	791.90	131.98	18.90
Total		**30.93**	**292.70**	**79.71**	**12.41**	**52.21**	**492.80**	**134.34**	**21.37**	**84.02**	**791.90**	**216.00**	**31.06**
Totals													
Total Reserves		**32.59**	**292.70**	**81.37**	**12.61**	**54.23**	**492.80**	**136.36**	**21.62**	**86.33**	**791.90**	**218.31**	**31.34**

Table 3: AGR TRACS International certified Aje field reserves

In addition to these reserves, TRACS certified gross unrisked technical contingent resources of 1C 4, 2C 9 and 3C 17.5 million barrels of oil. Panoro's net attributable resources are 1C 0.49, 2C 1.1 and 3C 2.13 million barrels. These resources would be accessed by additional future wells in the Cenomanian reservoir and oil rim of the Turonian reservoir.

The license, Oil Prospecting Lease ("**OPL**") 309, was originally awarded to YFP in July 1991 in the indigenous bid round by the Ministry of Petroleum Resources. Following the discovery of the Aje field the license was converted into OML 113 in June 1998 with a 20 years lease term. Renewal of the license for an additional period of 20 years was obtained in 2018.

OML 113 is tax/royalty concession. There is an approximate 4% royalty on all production and the Nigerian deep water tax regime has 50% Petroleum Profit Tax ("**PPT**") and 30% corporate Income tax for gas. See section 9.8 "Fiscal terms" for more information about the tax regime under which the Company operates.

9.5.6 Gabon *- Dussafu Marin Permit (8.33% Interest)*

9.5.6.1 Overview of Southern Gabon Sub-Basin in Gabon

The Gabon Coastal basin lies predominantly within Gabon except for the small northern part that lies in onshore Equatorial Guinea. The basin is up to 300 km wide, its eastern limit being marked by outcropping Precambrian basement and metasediments, while the first occurrence of oceanic crust defines the western limit of the basin. The basin is divided into the northern sub-basin and southern sub-basin by thick sediments of the Ogooue Delta deposited through central Gabon. The onset of rifting began during the Late Jurassic times in response to the rotation of the South American plate away from the African plate. Subsequently during Early Cretaceous times a series of rift grabens was formed which became depocentres for lacustrine, fluvial and continental sediments. The Dussafu block reservoirs were deposited at this time. The rift deposition culminated with an early Aptian unconformity and a widespread deposition of a series of evaporates consisting largely of Aptian aged salts. During the drift phase marine conditions prevailed with deposition of transgressive marine platform carbonates on the shelf. The minor westward basin tilting, combined with preliminary Albian sediment loading, initiated salt movement.

The main petroleum system in the southern Gabon sub-basin consists of hydrocarbons generated from Lower Cretaceous middle rift phase Melania formation Lacustrine shales that have migrated into pre-salt non-marine clastic reservoirs, such as the Gamba and Dentale. The southern sub-basin has been explored since the 1950's but only recently has seismic technology progressed to allow improved understanding of the pre-salt geology and structuration. Panoro and our partner Harvest have been at the forefront of exploration success in this basin with discovery of two oil fields in Dussafu in the last four years.

9.5.6.2 Dussafu Development – Gabon

Overview and background

The Dussafu block lies at the southern end of the South Gabon sub-basin in water depths ranging from 100 – 500 metres. The Dussafu block is a Development and Exploitation license with multiple discoveries and undrilled structures lying within a proven oil and gas play fairway within the Southern Gabon Basin. Most of the block lies in less than 200 m of water and has been explored since the 1970s. To the north west of the block is the Etame-Ebouri trend, a collection of fields producing from the pre-salt Gamba and Dentale sandstones, and to the north are the Lucina and M'Bya fields which produce from the syn-rift Lucina sandstones beneath the Gamba.

A total of 21 wells have been drilled in the greater Dussafu block to date, of which six have been pre-salt discoveries (five oil and one gas) and oil shows are present in most other wells. Panoro has participated in the last three exploration wells, all of which both encountered hydrocarbons; Ruche (2011), Tortue (2013) and Ruche North East (2018).

In 2014, an Exclusive Exploitation Authorization (EEA) for an 850.5 km^2 area within the Dussafu PSC was awarded. A Field Development Plan (FDP) for the EEA area was subsequently approved and a final decision to start developing the license was taken in 2017. The EEA area includes the five oil fields discovered on the license to date and numerous undrilled structures that could be economically and expeditiously developed through the EEA area development infrastructure. The EEA allows the Dussafu joint venture partners to exploit hydrocarbon resources in the area of the EEA for up to 20 years from first oil production. In 2016 the remaining portion of the greater Dussafu license area outside of the EEA area was relinquished. The first field in the EEA area, Tortue, started oil production in September 2018 from two initial horizontal development wells drilled in the first half of 2018. The oil from the Tortue wells is produced via subsea trees and flowlines to a leased FPSO for processing, storage and export. Further development plans, likely to consist of up to four additional subsequent wells tied back to the FPSO are being finalised. First oil from this phase is planned for 2020.

In February 2018, Netherland, Sewell and Associates, Inc. ("**NSAI**") certified (3rd party) gross 1P Proved Reserves of 15.9 MMbbls in the Gamba and Dentale reservoirs of the Tortue field. Gross 2P Proved plus Probable Reserves at Tortue amounted to 23.5 MMbbls in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at Tortue amounted to 31.4 MMbbls. In addition to these Reserves NSAI also certified gross 1C Contingent Resources of 3.7 MMbbls and gross 2C Contingent Resources of 11.6 MMbbls in the Tortue field.

The Tortue field at Dussafu commenced production in September 2018 and was being tested at the date of this document. The expected level of production since commencement to end of 2018, is between 10,000 to 15,000 bopd gross (Net to Panoro: between 833 to 1,250 bopd representing Panoro's share before royalty and production sharing with the Gabonese government (see section 9.8.2 "*Fiscal Regulations Gabon*")). The JV partnership expects the stabilised production from the field to be in the middle of this range.

The partner and operator in the license is BW Energy Dussafu B.V., a fully owned subsidiary of BW Offshore with 91.67% interest.

Tullow has confirmed their intent to exercise the 10% back-in right into the Dussafu license as stipulated in the production sharing contract (PSC). Tullow will be required to pay a portion of past costs and, following completion of this back-in, Panoro's interest in the Dussafu Marin license will be 7.5%.

Geological description

The primary hydrocarbon-bearing zones of interest in Dussafu are the early Cretaceous Gamba and Dentale sandstones. Gamba is a fining upward clastic sequence deposited as a widespread blanket post a significant period of uplift and source region rejuvenation known as the Aptian peneplanation. Gamba sands were deposited in a fluvial-distributary system flowing basinward from fan delta systems, which were re-established along border faults. These sandstones have excellent reservoir properties with porosities usually in the mid to high 20% and permeability upwards of 1 Darcy. Immediately below the Gamba and Aptian unconformity lies the Barremian to Early Aptian Dentale formation. Dentale was deposited in a fluvial-lacustrine setting characterised by stacked belts of meandering to anastomosing fluvial and distributary channels with thick intervals of associated crevasse splay, mouthbar, lake shoreline and offshore lake facies.

The Barremian age Melania shales are the organic-rich source rock and were deposited in a low-energy lacustrine environment. The source rock consists of varved, pyritic shale and has an average TOC content of over 6 weight percent.

The fields discovered to date in Dussafu are broad anticlines with hydrocarbons trapped by the overlying Vembo shale and Ezanga salt at Gamba, and rift structures with multiple stacked Dentale sandstone reservoirs. In the Dentale section the seal is provided by intraformational shales.

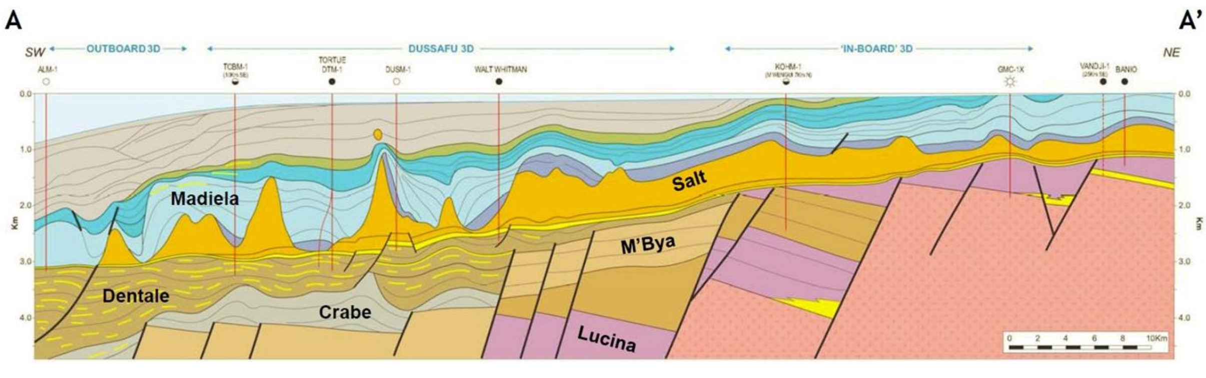


Figure 8: Geoseismic cross section Dussafu area

GMC-1X was drilled in the shallow part of Dussafu in 1975 by Gulf and found a 25 metre gas column in Gamba. Resources for this small gas field are estimated at around 150 bcf.

The Moubenga field in the western side of Dussafu was discovered by Elf in 1981. The discovery well encountered 12 metres of net pay in multiple stacked Dentale sandstones with porosities of 20%. A DST was conducted in the main pay sand and flowed at a rate of 2,730 boepd.

Walt Whitman was discovered in 1996 by Amoco and the well encountered a 17 metre oil column in Gamba which was not tested.

Ruche was drilled in 2011 and appraised by two sidetracks. The well found 17 metres of pay in a 29 metre oil column in Gamba confirmed by the two sidetracks. Porosities were logged at just over 19% and although a test was not made oil samples were recovered. The discovery well was deepened to the middle Dentale and found a 50 metre oil column with three separate hydrocarbon bearing sands. Reservoir properties in Dentale sands are around 18% porosity and 40mD permeability.

Tortue was discovered in 2013 and appraised with one sidetrack. DTM-1 found a 22 metre oil column in Gamba with 16 metres of net pay and 5 stacked hydrocarbon bearing sands in the Dentale. The most significant Dentale level is Dentale sand 6 which contained 20 metre net oil pay. The sidetrack confirmed the Dentale discovery. Reservoir properties were around 18% porosity in Gamba and 21% porosity in Dentale. Oil samples were recovered from both the Gamba and Dentale. Tortue was further appraised in 2018 with the DTM-3 appraisal well which found approximately 30 metres of hydrocarbon-bearing reservoir in the Gamba and immediately underlying Dentale sub-crop and additional hydrocarbon-bearing reservoirs in the Dentale.

The Ruche North East field was discovered in 2018. The well found 15 metres of good quality pay in Gamba and 25 metres of oil pay in stacked reservoirs in Dentale.

The economic gross 2P reserves in the Tortue field were certified by Netherland Sewell and Associates (NSAI) in 2018 as 2P Proved and Probable Reserves of 23.5 MMbbls of oil with contingent resources of 2C 11.6 MMbbls. The anticipated economic lifetime of the Tortue field is estimated by NSAI in the 2P case to be 9 years.

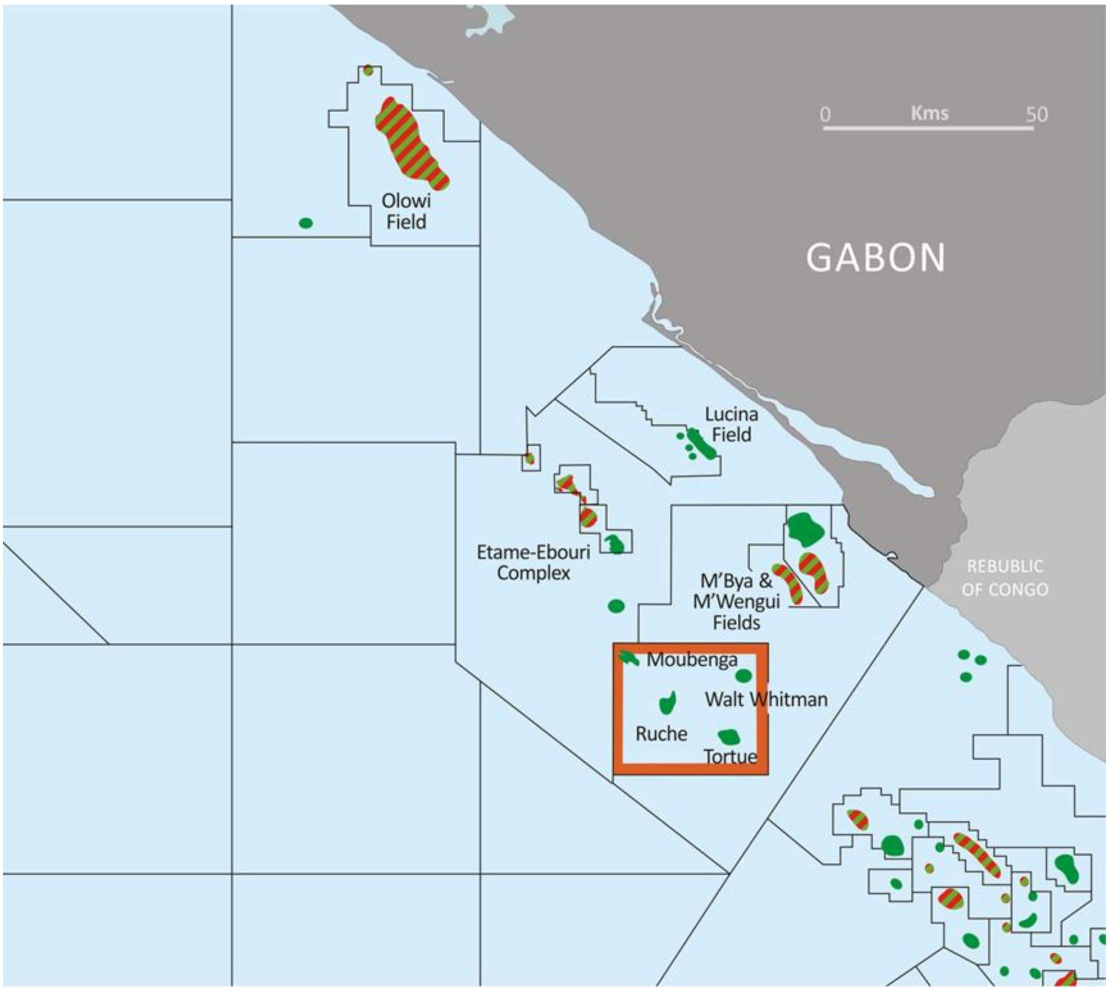


Figure 9: Dussafu license and surrounding fields

Development and resources

Development of the Ruche area EEA started with the Tortue field in 2017 following a Final investment Decision ("FID") by the partners. Phase 1 of the development consists of 2 horizontal production wells hooked up to an FPSO for storage and export via subsea trees. The two horizontal production wells, DTM-2H and DTM-3H, were drilled and completed in the Dentale D6 and Gamba reservoirs in 2018. Subsea trees were installed following the completion of the wells and subsea flowlines and a riser system were subsequently installed at the field ready for production startup. The FPSO arrived in Gabonese waters and was moored in position and connected to the production system in August 2018. First oil at Tortue was achieved in September 2018.

The NSAI report, dated end of 2017, provided the following estimate for oil reserves of the Tortue field.

As of 31 Dec 2017	Interest	1P (Low Estimate)				2P (Base Estimate)				3P (High Estimate)			
	%	Liquids	Gas	Total	Net	Liquids	Gas	Total	Net	Liquids	Gas	Total	Net
		MMbbl	Bcf	MMBOE	MMBOE	MMbbl	Bcf	MMBOE	MMBOE	MMbbl	Bcf	MMBOE	MMBOE
On Production													
Tortue Field	8.333	15.9	-	15.9	1.07	23.50	-	23.50	1.55	31.40	-	31.40	1.75
Total Reserves		**15.9**	**-**	**15.9**	**1.07**	**23.50**	**-**	**23.50**	**1.55**	**31.40**	**-**	**31.40**	**1.75**

Table 4: Reserves for the Tortue field

In addition to these reserves, NSAI certified gross unrisked technical contingent resources at Tortue of 1C 3.7, 2C 11.6 and 3C 28.9 million barrels of oil. Panoro's net attributable resources at Tortue are estimated as approximately 1C 0.2, 2C 0.6 and 3C 1.5 million barrels. These resources would be accessed by additional future wells in at the field. Total net contingent resources net to Panoro over the Dussafu license are approximately 2C 1.5 million barrels.

9.6 ENVIRONMENTAL ISSUES THAT MAY AFFECT THE COMPANY'S UTILIZATION OF THE TANGIBLE FIXED ASSETS

The Company is not obliged to carry out environmental protection measures that would be significant to the business or financial situation. However, all phases of the oil business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and state and municipal laws and regulations. Environmental legislation provides for, amongst other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Elements of the Group's activities, products or services that can interact with the environment are produced formation water including chemicals, emission of greenhouse gases and the risk of acute oil discharges including loss of well control. The Group's license portfolio includes seven production licenses, and three exploration licenses or permits, the activities within which may be classified as exploration, development or production. Panoro defines its status in certain of these license blocks as partner, and one of these license blocks as operator. To the extent Panoro can control and influence the environmental aspects in each production license area is dependent on its status as operator or partner and is fundamental to the practical application of the Panoro Group's environmental management system.

Where Panoro is a partner in a license, the primary responsibility for the environmental management of the activities within the license area rests with the designated operator. However, as Panoro holds joint and shared liability in connection with any environmental damage from activities undertaken in the license block, it is in the Company's best interest from a risk management perspective to ensure that the operator has environmental management provisions that are consistent with its environmental standards. As such, in partner licenses, Panoro assesses and aligns its environmental management provisions with those of the operator.

Panoro is committed to identify all its aspects and impacts, shall assess their significance, and ensure that appropriate operational controls are in place for those considered to be significant.

Panoro applies a broad definition of 'environmental aspects' and considers that, in addition to the physical activities that could lead to an environmental impact, the selection of other operators with whom Panoro chooses to invest (as a partner) in a license group is also an aspect which can influence the occurrence and/or extent of potential environmental impacts. Similarly, Panoro's selection of contractors to undertake activities on its behalf where it is the operator is also an aspect that can influence the extent of potential environmental impacts.

There are no material differences between the legal frameworks in Nigeria, Gabon and Tunisia offshore licenses in this respect.

9.7 LEGAL FRAMEWORK FOR PETROLEUM BUSINESS

9.7.1 The regulatory framework for Nigeria

By the provisions of the Nigerian constitution and the Nigerian Petroleum Act, ownership of petroleum is vested in the Nigerian government on behalf of the people of Nigeria. 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 broad powers including the powers to grant 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.

The Local Content Act was enacted in April 2010 and provides a framework for increasing Nigerian participation in all sectors of the Nigerian oil and gas industry, including the core upstream and support services of the Nigerian energy industry. The Local Content Act prescribes minimum thresholds for Nigerian participation in activities, generally provides for preferential treatment of Nigerian companies (i.e., companies with a minimum of 51 per cent. Nigerian equity holdings) in the award of oil blocks and licenses and provides for exclusivity to Nigerian indigenous service companies that demonstrate their capacity to operate in land and swamp terrain. The Local Content Act further provides that any project or contract with a budget of over US$ 100 million must contain a specific labour clause requiring a minimum percentage of Nigerian employees in specific cadres as may be stipulated by the Nigerian Content and Development Monitoring Board. Furthermore, the operator or developer of the project must limit the number of expatriates in management positions (the current limit is a maximum of 5%). The Local Content Act also requires that operators retain a minimum ten per cent. of their total revenue from operations in Nigeria. Non-compliance with the provisions of the Local Content Act in the award or execution of a project or contract can result in the cancellation of the project or a fine of up to five per cent. of the project sum. The risks for the Group associated with the Local Content Act and other local laws and regulations are further described in Section 2.2 "Risks relating to the jurisdictions in which the group operates".

The passage into law of the Nigerian Petroleum Industry Bill ("PIB") could create local ownership control requirements and additional fiscal and regulatory burdens on the parties to the Aje field. The PIB seeks to introduce significant changes to legislation governing the oil and gas sector in Nigeria, including new fiscal regulatory and tax obligations and expanded fiscal and regulatory oversight that may impose additional operational and regulatory burdens on the operations under the Aje field and impact the economic benefits anticipated by the parties to the Aje field. Any such fiscal and regulatory changes could have a negative impact on the profits allocable to the Aje field and its owners. The current status of the PIB is uncertain and it is uncertain if, and if so; when and with which content, the PIB will enter into force as law in Nigeria. A more detailed description of the PIB and the further possible risks for the Group associated with the PIB is set out in Section 2.2 – "Risks relating to the jurisdictions in which the Group operates".

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 nil in deep offshore areas to 20 per cent. 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.

In addition to federal legislation, each Nigerian state in which oil and gas business is undertaken enacts laws setting environmental standards and regulating land ownership and use, some of which restrict transportation and storage of oil and natural gas in certain areas and storage of oil and natural gas in certain areas.

The Company's subsidiary Pan-Petroleum Aje Limited, either directly or through its partnership in the OML 113 license, ensures that the operator adheres to all the requirements mentioned in this section, where applicable.

9.7.2 The environmental framework for Nigeria

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 as follows:

- Environmental Guidelines and Standards for the Petroleum Industry in Nigeria (EGASPIN) by DPR (2002).

- 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.

9.7.3 The regulatory framework for Offshore Gabon

The Ministère des Mines, de l'Énergie et du Pétrole regulates the upstream oil and gas industry in Gabon. Day-to-day responsibility for the upstream sector is run through the Direction Générale des Hydrocarbures ("**DGH**").

There are two separate types of contract in Gabon. Older fields operate under the terms of a concession agreement whereby only royalty and corporation tax is paid. The second type of contract is a production sharing agreement, introduced for the first time in 1977.

Up until 2014 the fiscal and regulatory framework of Gabon featured few hard and fast rules. Successive model contracts issued by the government only acted as guidelines and all fiscal aspects of each contract were negotiable. The terms of each PSC tended to be two periods of five years each, or five years, plus three years, plus two years. Work commitments and exploration costs on each PSC were completely negotiable.

In September 2014 a new hydrocarbons law came into force in Gabon. The New Law largely codifies the most recent contractual practice. New provisions applicable to the downstream sector have also been introduced but they mainly set general principles. Certain matters remain subject to further clarification as the New Law is in some instances unclear and leaves a number of matters to implementing regulations. The New Law also provides for certain transitory provisions.

In terms of application of the New Law to existing PSCs such as Dussafu, the principle is that all hydrocarbons agreements entered into prior to the publication of the New Law will remain in full force and effect with terms which may validly depart from those of the New Law, except for the obligations specified to be of immediate application. However, these arrangements cannot be renewed or extended without conforming to the terms of the New Law. New discoveries within the perimeter of an existing arrangement will be fully governed by the provisions of the New Law. Implementation of the following within the deadlines prescribed by the New Law is required even for existing investments: (i) decommissioning funds, (ii) limitations on gas flaring, (iii) constitution of PID and PIH provisions and (iv) compliance with the licensing requirements for midstream and downstream activities.

9.7.4 The environmental framework for Gabon

Oil and gas exploration and production activities are regulated by Law N°14/82 of 24th January 1983. The main environmental legislation in Gabon is Law No 16/93 relating to the Protection and Improvement of the Environment, also known as "Code de l'Environnement". The Law aims to foster a sustainable use of resources and development, limit pollution and nuisances, and improve the environment. The implementation of these principles under the law is the responsibility of the Minister of Environment.

Decree No 539 applies the principles of article 67 of Law 16/93 and abrogates Decree No 405. The Decree requires oil and gas operators to submit to the Environmental Administration a project notice, in order to elaborate directives specific to the project. In order to elaborate these directives, the operator might have to organise a site visit. In addition, operators are requested to undertake a consultation process, including presenting the project to the local populations. Minutes of the meetings must be signed by the authorities that attended.

The decree also specifies the requirement for an Environmental Impact Assessment, with 15 copies of the final document (in French) having to be submitted to the Environment Ministry. Under the regulations the Ministry has 30 days to review the document and give his recommendation.

In case of approval, the Ministry delivers an authorisation. If the recommendation is unfavourable, the Ministry has to provide his motives.

If no response has been made by the Ministry within a month of reception of the document, the applicant can assume consent has been given and may proceed with the proposed operations.

A period of public consultation must also be carried out. This involves a publication of an article in the Newspaper "Union" notifying that the EIA is available for comments during ten days. The Ministry can only approve the EIA once the consultation period is over.

Decree No 541 regulates the elimination of wastes and requires from all waste producers and owners to dispose of these wastes if they are potentially harmful to the environment. Decree No 542 regulates the dumping of some products in superficial, underground and marine waters. Decree No 543 determines classified installations subject to either a declaration or an authorisation. Oil and gas extractive installations, in particular, are subject to an authorisation. Decree No 545 regulates the recovery of used oil, its collection and recycling. Oil spill risks and relative emergency response arrangements are governed by Law n°21/04 of 2nd February 2004 and Decree No 653. Decree No 653 relative to the preparation and response to pollution by hydrocarbons provides the framework of the Gabonese Response in case of an oil spill, which would consist in deploying the National Emergency Plan (Plan d'Urgence National - PUN). Offshore response measures are the responsibility of the "Marine Nationale", whereas onshore response measures are to be coordinated by the "Ministère de l'Intérieur" via the "Direction de la Protection Civile".

Law 003/2007 on National Parks prohibits activities likely to negatively impact National Parks environment within their boundaries and a buffer zone of five kilometres around. Only human activities not impacting the environment can be authorized. This authorization must be provided by the relevant minister after consultation with the organism in charge of the National Park. The beneficiary of the authorization must pay a fee according to applicable modalities and rates. Under civil law, he's responsible of any damage caused by to the National Park because of its activity.

9.7.5 The regulatory framework for Tunisia

The Ministry of Energy, Mines and Renewable Energies is the authority in Tunisia responsible for the supervision of the hydrocarbons sector and granting permits. The General Hydrocarbons Directorate "**Direction Générale des Hydrocarbures**" ("**DGH**"), which is located within the Ministry, is the body in charge of implementing the states policies in the field of hydrocarbons.

The DGH studies permits and concession applications and proposes their allocation to the Minister of Energy, Mines and Renewable Energies.

Permits are granted through a convention concluded with the state and approved by law. The purpose of the convention is to summarise the agreement between the Conceding Authority (the state of Tunisia represented by the Minister of Energy, Mines and Renewable Energies) and to regulate the operations undertaken directly or indirectly by the licensee.

All permits are granted in association with the National Company for Petroleum Activities "**Entreprise Tunisienne d'Activités Pétrolière**" ("**ETAP**") through a Production Sharing Agreement ("**PSA**") or a Joint Venture Agreement ("**JVA**").

Under a PSA, the permit is granted by the Conceding Authority to ETAP as title holder, ETAP will afterwards enter into an agreement with a Petroleum company as contractor which will be entrusted with the research and exploitation of the hydrocarbons. The PSA will have to be approved by the Conceding Authority in order not to be considered void.

Under a JVA, the permit is granted by the Conceding Authority to ETAP and its partner. The percentage of participation for each of them is provided by the convention.

There are currently three legal regimes that apply to the Oil and Gas sector:

1) The regime that is regulated by the Decree dated December 13th, 1948, instituting special provisions in order to facilitate the research and exploitation of mineral substances of the second group, Law No 58-36 dated March 15th, 1958 amending the Decree dated December 13th, 1948 and Decree dated January 1st 1953 on Mines and which applies to permits and concessions granted until 1985.

2) The regime that is regulated by Decree-Law No 85-9 dated September 14th, 1985, instituting special provisions regarding the research and production of gaseous and liquid hydrocarbons and Law No 87-9 amending Decree Law No 85-9 and which applies to permits and concessions granted from 1985 to 1999.

3) The regime that is regulated by the hydrocarbons code and that applies to permits and concessions granted after 1999, the date of enactment of the Code.

The applicable regime will depend on the date the permit or concession was granted. In our case, Cercina, Gremda and Rhemoura are under the provisions of Decree-Law 85-9, Hejeb-Guebiba is subject to the provisions of the special convention and Cercina Sud is subject to the provisions of the Hydrocarbons Code.

9.7.6 The environmental framework for Tunisia

Environmental guidelines in Tunisia related to Oil and Gas exploration and production activities are provided for by various legal texts.

The Hydrocarbons code (the "**Code**") provides for some of those guidelines as it is the code regulating the Oil and Gas sector. Pursuant to the Code, the holders of a permit or an exploitation concession need to undertake their activities while complying with the environmental legislation in force. The holders are therefore obligated to elaborate an environmental impact study that should be approved prior to each phase of the research and exploitation works. Decree No 2005-1991 fixes the categories of units subject to the environmental impact study and the ones subject to a book of specifications.

In addition, any pollution that occurred on the holders' site needs to be notified to the head of the department responsible for hydrocarbons as well as the competent authority.

At the expiration of a permit or an exploitation concession, the holder is required to restore the rendered surfaces and/or the abandoned exploitation sites to their original state so that no harm is done to the environment.

The Conceding Authority has the power to order the immediate cessation of work in the event of serious infringements affecting the environment.

Companies, including those in Oil and Gas, producing wastes, are required pursuant to the provisions of Law No 96-41 dated 10 June 2018, to dispose of their wastes if harmful to the environment. The list of dangerous wastes is provided by Decree No 2000-2339.

In addition, Oil and Gas companies will be required, under the provisions of Decree 2002-693, to collect and stock lubricating oil under conditions which would avoid their mix up with other products and to deliver the oils to specialists who can manage the disposal of their wastes.

Chapter 7 of the water code, along with various legal texts, prohibits certain behaviours that can harm waters such as dumping and immersion into sea waters. This is supported by Decree 2009-1064, however, the immersion of a certain category of wastes and other materials (listed in schedule A of this Decree) is allowed following the obtainment of an authorisation from the Minister of the Environment.

Discharge into the receiving environment (sea, lakes, lagoons, irrigation canals…) is also prohibited as regulated by Decree No 85-56. The limited value for this effluent discharge is provided for by the Order of the Minister of Local Affairs and the Environment and the Minister of Industry and Small and Medium-sized Enterprises dated 26 March 2018.

Decree No 94-1885 regulates the dumping and discharge of residual waters, other than domestic, in sanitation networks implemented in the intervention areas of the sanitation office.

Law No 2007-34 dated June 4th, 2007, regulating air quality aims to prevent, limit and reduce air pollution and its negative impacts on the population and the environment.

Onshore and Offshore facilities for the extraction and treatment of hydrocarbons are considered, pursuant to the provisions of The Order of the Ministry of Industry, Energy and Small and Medium-sized Enterprises dated November 15th, 2005, as category one dangerous establishments.

These establishments are required to obtain an authorisation for their opening and exploitation as requested by Decree No 2006-2687.

9.8 FISCAL TERMS

The main terms governing the licenses in which Panoro has interest are summarised in Table 5 below.

License	Country	Expiry	Royalty	Tax	Production Sharing to Contractor
OML 113	Nigeria	June 2038	4%	50%	-
Dussafu	Gabon	September 2038	4%-12%	-	50%-30%
Sfax Offshore Exploration Permit	Tunisia	December 2018	-	-	42.5%-25%
Ras El Besh	Tunisia	September 2038	-	-	40%-55%
Cercina	Tunisia	February 2024	2% - 15%	50% - 75%	-
Cercina South	Tunisia	November 2034	2% - 15%	50% - 75%	-
Gremda / El Ain	Tunisia	December 2018	2% - 15%	50% - 75%	-
Guebiba	Tunisia	June 2033	15%	60%	-
Rhemoura	Tunisia	January 2023	2% - 15%	50% - 75%	-

Table 5: Summary of Main Terms

9.8.1 Fiscal Regulations Nigeria

Petroleum Profits Act 2004 ("PPTA")

The PPTA governs the taxation of upstream operations with the baseline applicable tax for crude oil operations set at 85 per cent. of chargeable profits with royalties ranging between nil and 20 per cent. depending on water depth. A lower tax rate of 65.75 per cent. is payable by companies that have not yet amortised all pre-production capital expenditure for the first five years. In practice, however, the Nigerian government has not applied this statutorily prescribed rate to marginal field operations, but instead has applied concessionary rates of 50-55 per cent. of chargeable profits.

The Deep Offshore & Inland Basin Production Sharing Contract Act ("DIBPSA")

The DIBPSA was enacted further to the PPTA and applies to production sharing contracts for concession areas situated deep offshore and in Nigeria's inland basin. The law was enacted to provide fiscal incentives to encourage exploration in areas that were at the time under-utilised. The main incentive is a lower tax rate of 50 per cent. (as opposed to the 85 per cent. set by the PPTA), lower royalty rates (as low as zero per cent. for deep offshore areas) and the introduction of an Investment Tax Credit of 50 per cent for production sharing contracts executed before 1 July 1998 or an Investment Tax Allowance of 50 per cent for production sharing contracts executed after 1 July 1998. The DIBPSA is administered by the Federal Inland Revenue Service.

In addition to taxation of petroleum profits, pursuant to the PPTA or DIBPSA, there is also a levy of three per cent. imposed by the Niger Delta Development Commission Act 2000 chargeable on the total annual budget of any oil producing or gas processing company operating onshore and offshore of the Niger Delta area. Interests in assets located offshore in the Niger Delta will be subject to these provisions.

The Local Content Act requires that one per cent. of every contract awarded to any operator, contractor, subcontractor, alliance partner or any other entity involved in any project, operation, activity or transaction in the upstream sector of the Nigerian oil and gas industry shall be deducted at source and paid into the Nigerian Content Development Fund.

The Local Content Act also requires all operators, contractors and sub-contractors in the oil and gas industry to retain at least ten per cent of their total revenue from Nigerian operations in Nigerian banks.

There is also a two per cent. Education Tax imposed on the assessable profits of every company registered in Nigeria and five per cent. VAT charged on all supply of goods and services except goods and services expressly exempted by the Local Content Act.

Tax Incentives

The PPTA also provides for a number of incentives to encourage utilisation of natural gas, usually although not exclusively found when exploring for crude oil. These incentives apply exclusively to crude oil producers engaged in the utilisation of both associated and non-associated gas.

In order to encourage gas utilisation, the Nigerian government introduced incentives under the PPTA that would allow companies involved in the utilisation of gas to be taxed at the corporation tax rate of 30 per cent under the Companies Income Tax Act ("**CITA**"), in relation to the income from the gas utilisation project (as opposed to the 85 per cent and 50 per cent rates under the PPTA and DIBPSA, respectively). No definition is provided for utilisation of gas in the PPTA; however, the PPTA specifically provides that the incentives shall be available to companies that invest in natural gas liquids extraction facilities to supply gas in usable forms to downstream projects (such as aluminium smelting and methanol production) and other gas utilisation projects.

Companies that invest in the utilisation of associated gas are allowed to treat investments required to separate crude oil and gas from the reservoir into usable products as part of oilfield development. In addition to this, capital investment on facilities equipment to deliver associated gas in usable form can be treated as part of capital investment for oil development for tax purposes.

Under CITA, other incentives are available to gas utilisation companies, including a tax free period of up to five years for gas utilisation projects and attractive loan and capital allowance provisions amongst others.

9.8.2 Fiscal Regulations Gabon

Production Sharing Contracts

State Participation

The state has an option to participate in commercial discoveries. State participation became common after the second licensing round in 1986. The state equity interest increased with each successive licensing round to a maximum of 25% in the fourth round and sixth licensing rounds. In the seventh round the government indicated that state participation was now negotiable, which marked an important change in approach and the average is now 10%. In the Dussafu licence, this option is 10% and has been sold to the Tulip Consortium which is 50% owned by Tullow Oil Plc.

Carry & Reimbursement

The state does not reimburse its share of past exploration costs. It does however pay for its share of any exploration wells drilled within the production permit after start-up. The state's share of development costs are usually carried although the government has an option to pay for some or all of its share of costs as they are incurred.

Costs are reimbursed out of 70% of the state net profit interest. (Early PSCs stipulated that the state reimbursed its share of costs using 100% of its net profit interest, but nowadays payback is slower). The state pays interest on carried costs at the Banque des Etats de l'Afrique Centrale (BEAC) rate.

Production Bonuses

Production bonuses are payable. A production bonus is payable when the field commences production (usually US$1-3 million) and also when specified production rates are reached. Typical bonus payments are US$2-3 million when production reaches 10,000 b/d and US$2-6 million when 20,000 b/d is achieved. In line with the other recent fiscal incentives new contracts have included smaller bonus payments. Production bonuses are not cost recoverable.

Area Rentals

An annual surface royalty based on total surface area is due yearly in advance. The gross annual surface rent is approximately US$ 700,000, one third of which is Panoro's share.

Training Fees

The operator has the obligation to contribute to the training of Gabonese nationals. Contribution amounts are negotiable and are cost recoverable.

Other Bonuses and Fees

Bonuses are also payable when contracts are renewed for a second or subsequent period. These bonuses are not cost recoverable.

Indirect Taxes

VAT / Sales Taxes

VAT is levied at 18% on both imported and domestic goods. During exploration no VAT is imposed.

Royalty and Other Production Taxes

Royalty

A royalty is payable on total allowable production ("**TAP**"). TAP is defined as gross production less volume for in-field use less the volume used for reservoir management. Royalty rates can either be fixed (typically 10%) or on a sliding scale based on production rates (5% at start-up, grading to

20% at peak). Terms for ultra-deepwater PSCs contain a minimum royalty payment of 5%. A royalty holiday period of three or five years also applies to recent contracts. Payment can either be in cash or kind.

Other Production Taxes

Production Levy

There is a US$0.05 per barrel levy on gross production paid into the National Hydrocarbon Fund. This levy has been non-negotiable in previous licensing rounds but in the seventh round it has become open for negotiation.

Domestic Market Obligation ("DMO")

All fields are required to supply a quantity of crude oil to the SOGARA refinery at Port Gentil. The quantity is in proportion to the contractors entitlement compared to the total production of Gabon. The crude is sold to the refinery at a 25% discount. This discount is cost recoverable. In practice only Mandji crude is used as a feedstock at the refinery. The other crudes (Oguendjo, Gamba, Lucina and Rabi) are bartered.

Contractor Revenue Entitlement

The contractor is entitled to revenue from sales of cost recovery production and its share of profit oil/gas and pays royalty and taxes on its net income.

Liquids Pricing

DMO oil is supplied at a 25% discount to the prevailing market price.

PSC Cost Recovery

Cost Recovery Ceiling

In each year of production a percentage of net production after royalty is available to offset costs. The cost recovery ceiling is typically 65% but varies by licensing round, generally increasing over time. Cost recovery ceilings can be increased for marginal field developments or incremental developments on existing fields by negotiation with the government on a case-by-case basis.

Recoverable Costs

All costs are expensed and recoverable in the year in which they are incurred or the year in which commercial production commences, whichever is later. Interest on loans made from third party sources to fund development is also allowable for cost recovery.

Cost Carry Forward

Any unrecovered costs can be carried forward (without interest) for relief in subsequent years without limit.

PSC Profit Sharing

Production remaining after royalty and cost recovery is termed profit share and is divided between the contractor and the government. The basis on which this division is made is negotiable, based on tiered daily production rates with a different percentage profit share applicable to each tier. During the application process bidders must specify the various production rate tiers and the profit oil splits applicable to each tier.

Typical production based profit splits are given in the table below:

Profit Oil Splits (Onshore and Shallow Water Contracts)

Production ('000 b/d)	Government Share (%)	Contractor Share (%)
< 10	50	50

< 20	52.50	47.50
< 40	55	45
< 80	65	35

Corporate (or Petroleum) Income Tax

Taxable Income

The state pays tax on behalf of the contractor.

Other Taxes

Capital Gains tax is payable on the sale of assets to non-affiliates.

9.8.3 Fiscal Regulations Tunisia

The applicable fiscal regulation in Tunisia will depend on the date a concession was granted.

There are currently three different tax regimes for the five concessions located in Tunisia. The Hajeb Guebiba concession is governed by the special convention regime (Convention Kerkennah Ouest), the Cercina, Gremda and Rhemoura concessions are governed by the regime of Decree-law 85-9. Finally, the Cercina Sud concession is governed by the Hydrocarbons code.

9.8.3.1 Special Convention Regime (Hajeb Guebiba)

Under the convention, concessions have a responsibility of payment in terms of rights, taxes and levies which are the following:

Proportional Royalty on Production

The proportional royalty on production is equal to 15% of the value or quantities of crude hydrocarbons lifted or sold by the concession holder.

Income Tax

The income tax rate for Hajeb Guebiba is equal to 60%.

Other Taxes

a) Payments in remuneration of the direct or indirect utilisation of roads and other systems or public utilities;
b) The tax on customs formalities (T.F.D) due on imports and exports;
c) Tax on transportation and circulation of vehicles;
d) Registration fees;
e) Stamp duties;
f) Unique tax on insurance;
g) Tax on rental value of professional and residential premises;
h) Tax vocation training;
i) Taxes paid by the suppliers of materials or products and which are usually included in the purchase price excluding, however, sales taxes; and
j) Fixed duty on concessions and exploration permits (similar to delay rentals).

9.8.3.2 Decree Law 85-9 Regime (Gremda, Cercina, Rhemoura)

Under Decree-Law 85-9, concessions have a responsibility of payment in terms of rights, taxes and levies which are the following:

Proportional Royalty on Production

The proportional royalty on production of hydrocarbons is determined based on the R-factor for the considered year by the concession holder.

For liquid hydrocarbons, proportional royalty varies according to the (R) factor and is determined as follows:

R factor value	Royalty Rate
R ratio inferior or equal to 0.5	2%
R ratio superior to 0.5 and inferior or equal to 0.8	5%
R ratio superior to 0.8 and inferior or equal to 1.1	7%
R ratio superior to 1.1 and inferior or equal to 1.5	10%
R ratio superior to 1.5 and inferior or equal to 2	12%
R ratio superior to 2 and inferior or equal to 2.5	14%
R ratio superior to 2.5	15%

For gaseous hydrocarbons, proportional royalty varies according to the (R) factor and is determined as follows:

R factor value	Royalty Rate
R ratio inferior or equal to 0.5	2%
R ratio superior to 0.5 and inferior or equal to 0.8	4%
R ratio superior to 0.8 and inferior or equal to 1.1	6%
R ratio superior to 1.1 and inferior or equal to 1.5	8%
R ratio superior to 1.5 and inferior or equal to 2	9%
R ratio superior to 2 and inferior or equal to 2.5	10%
R ratio superior to 2.5 and inferior to 3.0	11%
R ratio superior to 3.0 and inferior to 3.5	13%
R ratio is superior to 3.5	15%

Income Tax

Income tax rate for liquid hydrocarbons is calculated based on the value of the R factor as follows:

R factor value	Income Tax Rate

R ratio inferior or equal to 1.5	50%
R ratio superior to 1.5 and inferior or equal to 2.0	55%
R ratio superior to 2.0 and inferior or equal to 2.5	60%
R ratio superior to 2.5 and inferior or equal to 3.0	65%
R ratio superior to 3.0 and inferior or equal to 3.5	70%
R ratio superior to 3.5	75%

Income tax generated from a concession focusing mainly on the production of gas not associated with oil is calculated based on the (R) factor as follows:

R factor value	Income Tax Rate
R ratio inferior or equal to 2.5	50%
R ratio superior to 2.5 and inferior or equal to 3.0	55%
R ratio superior to 3.0 and inferior or equal to 3.5	60%
R ratio superior to 3.5	65%

Other Taxes

a) The fixed duty and the registration fees for permits and concessions;
b) Payments in remuneration of the direct or indirect utilisation by the Holder of roads and other systems or public utilities;
c) Duties, levies and taxes paid by the suppliers of services, materials or equipment and which are usually included in the purchase price excluding, however, sales taxes;
d) The tax on customs formalities (T.F.D) due on imports and exports; and
e) The registration of contracts of suppliers' works and services pertaining to the activities of exploration, appraisal, development, production, transportation, storage and marketing at the fixed duty.

9.8.3.3 Hydrocarbons Code Regime (Cercina Sud)

Under the Hydrocarbons Code, concessions have a responsibility of payment in terms of rights, taxes and levies which are the following:

Proportional Royalty on Production

The proportional royalty on production of hydrocarbons is determined based on the R-factor as in Decree-Law 85.9.

Please see Proportional Royalty section in 9.8.3.2 for the liquid and gaseous hydrocarbons R factor table.

Income Tax

The income tax is calculated based on the R-factor as in Decree-Law 85-9.

Please see Income tax section in in 9.8.3.2 for the liquid and gaseous hydrocarbons R-factor table.

Other Taxes

a) Fixed tax equal to the minimum inter-professional hourly wage of an ordinary worker for every full elementary perimeter (an area of 4 km). This tax must be paid whenever a new permit and/or concession is granted;
b) Fixed tax is to be paid per hectare of land included in the Exploitation Concession, equal to the guaranteed inter-professional hourly wage of an ordinary labourer, and this no later than June 30th, of each year. The said tax is equal to five times the guaranteed inter-professional wage per hour of the ordinary manoeuvre per hectare for inactive or underused concessions;
c) The registration at the fixed duty of the special convention and its appendices, amendments;
d) The registration at the fixed duty of all contracts for supplies, works and services relating to the holder's activities performed under the special convention;
e) Payments in remuneration of the direct or indirect utilisation by the holder of roads, systems and other elements of public or private property;
f) Tax on establishments of industrial, commercial or professional nature, for the benefit of local authorities;
g) Tax on constructed properties;
h) The customs services fees (RDP) and the data automatic processing fees due on imports and exports;
i) Taxes, duties and levies paid by the suppliers of services, goods, equipment, materials, products and raw materials or consumables which are normally included in the sale's price, exception made of the value added tax;
j) Taxes in transportation and circulation of vehicles; and
k) Unique tax on insurances.

9.8.4 Specific Terms and Conditions of the Licenses

9.8.4.1 Production Sharing Contract Dussafu Marin Permit

All work programme obligations under the PSC have been fulfilled. The Company's fully owned subsidiary Pan-Petroleum Cyprus Holdings Limited ("**PPHCL**") has a company guarantee to the State of Gabon to fulfil all obligations under the PSC. The third period of the Exploration Authorisation expired on 27 May 2016 and the area outside of the Ruche Area Exclusive Exploitation Authorization ("**EEA**"), which was entered into on 17 July 2014, was relinquished.

The Ruche Area EEA covers 850.5 km2 and contains five discovered fields and numerous undrilled structures that could be economically and expeditiously developed through the Ruche area development infrastructure. The Ruche Area EEA allows the Dussafu joint venture partners to exploit hydrocarbon resources in the area of The Ruche Area EEA for up to 20 years from first production which was achieved in September 2018.

The main specific terms relating to the Dussafu Exploration and Production Sharing Contract are set out in the table below.

Item	**Description**
Recovery of petroleum costs	Contractor is entitled to recover petroleum costs capped at 65% of net production per year. This cost recovery can raise to 75% of net production if three years after production commencement contractor has not recovered its share of petroleum costs
Carry forward of petroleum costs	If in a year the net production does not permit the contractor to recover petroleum costs, the petroleum costs not recovered are carried forward to succeeding years until full recovery of the petroleum costs.
Production Sharing of petroleum after petroleum costs recovery	<10,000 bbls/d State 50%, Contractor 50% 10,000-20,000 bbls/d State 52.5%, Contractor 47.5%

	20,000-40,000 bbls/d State 55%, Contractor 45% 40,000-80,000 bbls/d State 60%, Contractor 40% 80,000-100,000 bbls/d State 65%, Contractor 35% >100,000 bbls/d State 70%, Contractor 30%
Mining royalty (not considered petroleum costs)	<10,000 bbls/d 4% of total available production 10,000-20,000 bbls/d 6% of total available production 20,000-40,000 bbls/d 8% of total available production 40,000-80,000 bbls/d 10% of total available production >80,000 bbls/d 12% of total available production
Bonuses payable by Contractor to State (not considered petroleum costs)	US$ 1 million from commencement of hydrocarbon production US$ 2 million once average daily production reaches for the first time 20,000 bbls/d US$ 3 million once average daily production reaches for the first time 40,000 bbls/d US$ 3.5 million once average daily production reaches for the first time 80,000 bbls/d US$ 4 million once average daily production reaches for the first time 100,000 bbls/d

9.8.4.2 OML 113 Joint Operating Agreement

OML 113 is not governed by a PSC since it is a tax and royalty based lease. The OML lease may be renewed by the lease holders by application not less than 12 months before the date of expiration and the renewal shall be granted if the lessee has paid all rents and royalties due and has otherwise performed all his obligations under the lease. Ministerial consent for OML 113 licence renewal for a term of 20 years was granted by the Ministry of Petroleum Resources on 13 August 2018, subject to the satisfaction of customary financial conditions and a commitment to exploit the Turonian gas potential. There is however, no specific minimum spending requirements under the renewal terms. A renewal bonus of approximately US$ 9.9 million gross has been paid by the joint venture from Aje production cash flows. Other obligations are those that any OML lease holder has under the relevant Nigerian law such as the Petroleum Act, and includes a conduct of operations continuously and in a vigorous and business-like manner in accordance with good oil field practice. A negotiable renewal fee is payable. The costs are not expected to be significant and can only be determined with reasonable accuracy on engagement with the authorities closer to time.

The main specific terms relating to the OML 113 lease and the JOA as interpreted by Panoro are set out in the table below.

Item	**Description**
Royalty (Oil)	4% of total production times selling price used for the purpose of royalty calculations
Royalty (Gas)	5% of total production times selling price used for the purpose of royalty calculations
Oil tax rate	50% of taxable petroleum profits as defined under PPTA

Gas tax rate	30% of taxable profits derived from producing gas
Investment Tax Allowance / Petroleum Investment Allowance	50% of qualifying historical investments made to explore and develop the field
Education Tax	2% on assessable profits as defined for the purpose of determining education tax
VAT	5% on value of goods supplied
Custom Duty	Variable – on values determined for the purpose of customs duty

9.8.4.3 Sfax Offshore Exploration Permit

A three year renewal application for the Sfax Offshore Exploration Permit, which expired on 8 December 2018, was submitted and is currently under consideration by the authorities. The remaining outstanding work program for the renewal period that expired on 8 December 2018 is the drilling of one exploration well or payment of an estimated maximum of US$ 12 million (net to Panoro US$ 7.2 million) penalty. The costs attributable to Panoro in this section are after taking into account participation of Beender at 40%. The proposal in the renewal application is to defer the committed well to the second renewal period. With an estimated cost of US$ 6.1 million net to Panoro, this well could be drilled in the first half of 2019.

An application for the second renewal period, which is three years in duration (with possible extensions of a maximum of three more years), was submitted to the granting authorities. The committed work program of this period is the drilling of an additional exploration well with an estimated net cost to Panoro of US$ 6.1 million.

Under the terms of the Production Sharing Contract, a third renewal period may be up to four years in duration, providing a discovery has been made during the previous period(s). The work obligation in this period is the drilling of an exploration or an appraisal well.

The original PSC relating to the SOEP was signed on 20 July 2005 between Tunisian national oil company ETAP as Permit Holder and Atlas Petroleum Exploration Worldwide Ltd. and Eurogas International Inc., collectively as Contractors. The initial licensed area was 4,036 km2.

The Initial Exploration Period of four years started on 9 December 2005 and subsequently received a two-year Extension, plus a one-year Additional Extension. Thus, the Initial Exploration Period expired on 8 December 2012, at which point twenty percent (20%) of the initial area was relinquished. The current area of the SOEP is 3,228 km².

In 30 July 2018, Panoro Energy ASA acquired DNO Tunisia AS which has since changed its corporate name to Panoro Tunisia Exploration AS. The latter is the Operator with 87.5% working interest and 100% paying interest under the terms of an earn-out arrangement.

The SOEP is located inside proven Cretaceous and Tertiary oil fairways of the Pelagian Basin, proven by a myriad of surrounding discoveries and producing fields. The license already contains two undeveloped oil discoveries: the Jawhara discovery made by Total in 1976, and the Salloum discovery made by BG in 1997.

A significant number of exploration prospects/leads has been identified and characterized in the Sfax Offshore Permit. This prospectivity includes small and large independent structures allowing the possibility of both single and cluster field development scenarios.

The SOEP is favorably located adjacent to existing oil and gas production and transportation facilities with available spare capacity.

The PSC fiscal terms are attractive including cost oil to recover past expenditures by the Contractor and profit oil to share with the Permit Holder (ETAP). The cost recovery rate is based on a sliding scale dependent on average daily oil production rate.

The main specific terms relating to the Sfax Offshore Exploration and Production Sharing Contract are set out in the table below.

Item	**Description**
Petroleum costs recovery	The expenditures related to the prospecting work, exploration and appraisal operations shall be recoverable from any liquid or/and gaseous hydrocarbon deposit from the permit The expenditures related to the development, production, economic production and abandonment shall be recoverable in the same manner as described above but it will be attributed to the deposit to which they correspond and recovered from the production of said deposit.
Recovery of petroleum costs (Cost Oil / Cost Gas)	Contractor is entitled to recover petroleum costs for oil as set below: Monthly Average Barrels of Oil Per Day - Oil Cost Recovery 0 – 5,000 55% 5,001 – 10,000 50% >10,000 40% Cost Gas recovery is capped at 60% of the production.
Carry forward of petroleum costs	The recovery of the Oil and Gas costs continue until all the expenditures incurred during the prospection, exploration and development operations are fully recovered.
Production Sharing of petroleum after petroleum costs recovery (Profit Oil / Profit Gas)	The balance of the oil production, after cost oil recovery, is allocated between Contractor and NOC as follows: 0–5,000 bbls/d State 57.5%, Contractor 42.5% 5,001–10,000 bbls/d State 67.5%, Contractor 32.5% >10,000 bbls/d State 75%, Contractor 25% Profit Gas recovery is capped at 50% of the production after cost gas recovery.

9.8.4.4 Ras El Besh Exploitation Concession

In 2005, APEX and Eurogas submitted to the Energy Directorate (DGE) a plan of Development and an application for Ras El Besh Concession. In 05th September 2008, the 'arrêté' instituting Ras El Besh Concession was published in the official Tunisian gazette (JORT).

A Concession of an area of 68 km² was subtracted from the Sfax Offshore Permit and granted to APEX and Eurogas for a period of 30 years. The commitment is to develop and bring on stream the Ras El Besh field.

The first development well, REB-3, drilled in June 2008 downscaled significantly the resources of the field, putting the entire development project on hold.

In 2014, DNO acquired an 87.5% interest in the Ras El Besh Concession, while also assuming operatorship. Given that the initial 2005 PoD, designed for larger reserves, was no longer appropriate, the Contractor group and ETAP agreed in 2013 to review the original PoD and a revised PoD has been submitted to the ETAP and the Energy Directorate in March 2015. The main outcome of the PoD is that the Ras El Besh was not at that time an economically viable project.

Further to the transaction concluded between Panoro Energy ASA and DNO ASA to acquire DNO Tunisia AS, Ras El Besh concession is now operated by Panoro Tunisia Exploration AS with a working interest of 87.5%. Currently Panoro is in discussion with an Engineering Consultancy Office to update the PoD.

The Ras El Besh Concession is governed by the same PSC terms of Sfax Offshore Permit.
The main specific terms relating to the Ras El Besh Concession and Production Sharing Contract are set out in the table below.

Item	**Description**
Petroleum costs recovery	The expenditures related to the development, production, economic production and abandonment shall be recoverable in the same manner as described for the Sfax Exploration Permit but it will be attributed to the deposit to which they correspond and recovered from the production of said deposit.
Recovery of petroleum costs (Cost Oil / Cost Gas)	Contractor is entitled to recover petroleum costs for oil as set below: Monthly Average Barrels of Oil Per Day - Oil Cost Recovery 0 – 5,000 55% 5,001 – 10,000 50% >10,000 40% Cost Gas recovery is capped at 60% of the production.
Carry forward of petroleum costs	The recovery of the Oil and Gas costs continue until all the expenditures incurred during the prospection, exploration and development operations are fully recovered.
Production Sharing of petroleum after petroleum costs recovery (Profit Oil / Profit Gas)	The balance of the oil production, after cost oil recovery, is allocated between Contractor and NOC as follows: 0–5,000 bbls/d State 57.5%, Contractor 42.5% 5,001–10,000 bbls/d State 67.5%, Contractor 32.5% >10,000 bbls/d State 75%, Contractor 25% Profit Gas recovery is capped at 50% of the production after cost gas recovery.

9.9 COMPETITIVE POSITION

Panoro operates in a highly competitive environment, where all competitors offer the same product, crude oil. There is little differentiation with regards to the product throughout the industry, although the product may be offered with different quality (and with correspondingly different price). The market for oil producer is dominated by a few producers with a substantial share of total production and a very long tail of smaller producers.

Of a total supply of approximately of 98 million barrels per day in 2016, the top ten largest public producers had a market share of approximately 38 per cent.

Company	Estimated Production[1]	Share of production	Sources (publically available information
Gazprom	8.4	9%	Forbes Magazine
Rosneft	5.1	5%	Forbes Magazine
ExxonMobil	4.1	4%	Forbes Magazine
PetroChina	4.1	4%	Forbes Magazine
BP	3.2	3%	Forbes Magazine
Royal Dutch Shell	3.0	3%	Forbes Magazine
Chevron	2.6	3%	Forbes Magazine
Petrobas	2.6	3%	Forbes Magazine
Lukoil	2.4	2%	Forbes Magazine
Total S.A.	2.4	2%	Forbes Magazine
Top 10	**37.7**	**38%**	**Forbes Magazine**
Remaining producers	60.4	62%	
Total production	**98.1**	**100%**	**International Energy Agency**

These exclude private producers for which reliable information is not available such as Saudi Aramco and National Iranian Oil Co.

10. MARKET OVERVIEW

10.1 THE GLOBAL ENERGY MARKET

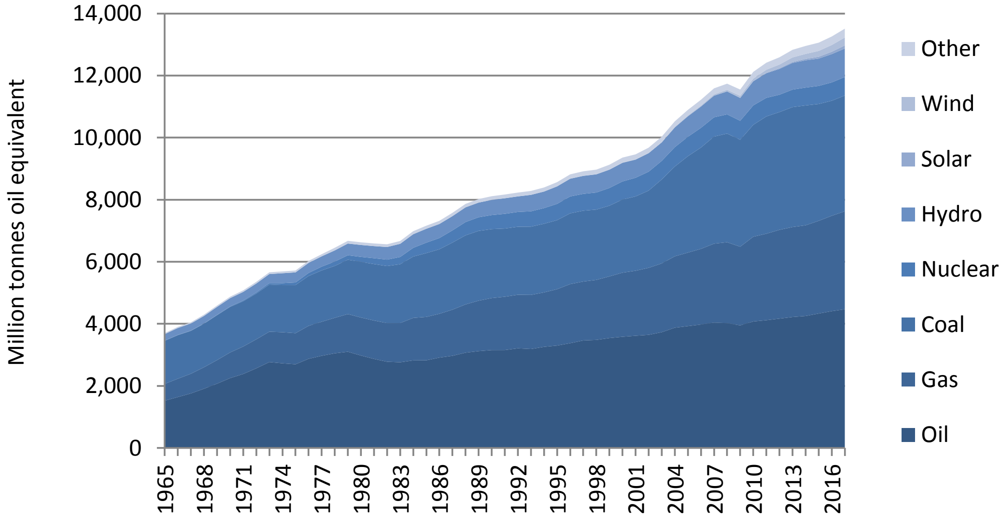
World energy consumption has steadily increased since the industrial revolution, a trend which is expected to continue in the medium term. Fossil fuels continue to supply more than 85 percent of the world's energy. Oil is the largest energy source, meeting 34 percent of the world's energy consumption, while natural gas accounts for 23 percent and coal for 28 percent.[2]

The world consumption of primary energy – including oil, natural gas, coal, nuclear, hydro power and other renewable energy – increased by 1.9 percent in 2017. Global oil consumption increased by 1.9 million barrels per day or 1.8 percent in 2017.

Figure 1 – Total world energy consumption 1965-2017 – distribution by fuel

[1] Million barres of oil equivalent produced per day

[2] BP Statistical Review of World Energy June 2018



Source: BP Statistical Review of World Energy June 2018.

10.2 OVERVIEW OF THE OIL MARKET

Oil is a common description of hydrocarbons in liquid form. Crude oil produced from different oil fields varies greatly in composition, and the composition and distribution of hydrocarbon components determines the weight of the oil, with light crude oil having a higher percentage of light hydrocarbons than heavier oil. Light oil requires less refinement to be usable and is therefore typically more valuable than heavy oil.

Oil is well suited for storage and transportation and is transported over long distances in large crude oil tankers or pipelines. Because of this, oil is a commodity with a well-developed global market. The prices are determined on the world's leading commodities exchanges, with NYMEX in New York and the ICE in London as the most important markets for the determination of global oil prices. Relative oil price differentials are primarily determined by the weight of the oil and its sulfur content, with WTI, the main benchmark for NYMEX, as the lightest and sweetest (lowest in sulfur) of the main benchmarks in oil pricing. Brent crude – the main benchmark for ICE – is slightly heavier.

Crude oil is used for a variety of purposes, the most important being the production of energy rich fuels, with approximately 70 percent of hydrocarbons being used for gasoline, diesel, jet fuel and other fuel oils. The remaining hydrocarbons are used as raw material for many chemical products, including pharmaceuticals, solvents, fertilizers, pesticides and plastics.

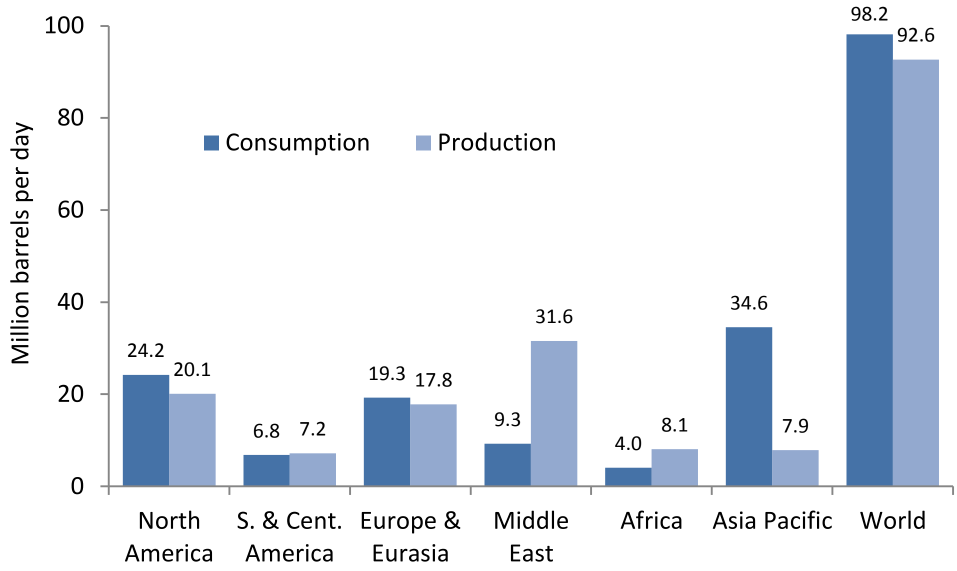
10.2.1 World oil production, consumption and reserves

World oil consumption in 2017 was approximately 98.2 million barrels per day, of which Asia Pacific, North America and Europe including Eurasia (most importantly, Russia) accounted for approximately 35 percent, 25 percent and 20 percent, respectively. Consumption in the Middle East was about 9.5 percent of the world total.

The Middle East is the world's largest oil producing region, accounting for 34% of the world total. North America is second behind the Middle East, accounting for 22 percent, followed by Europe and Eurasia with 19 percent.[1] Despite being the largest consuming region, oil production in Asia Pacific accounts for only 9 percent of total world production.

Figure 2 – World oil consumption and production by region, 2017

[1] BP Statistical Review of World Energy June 2018

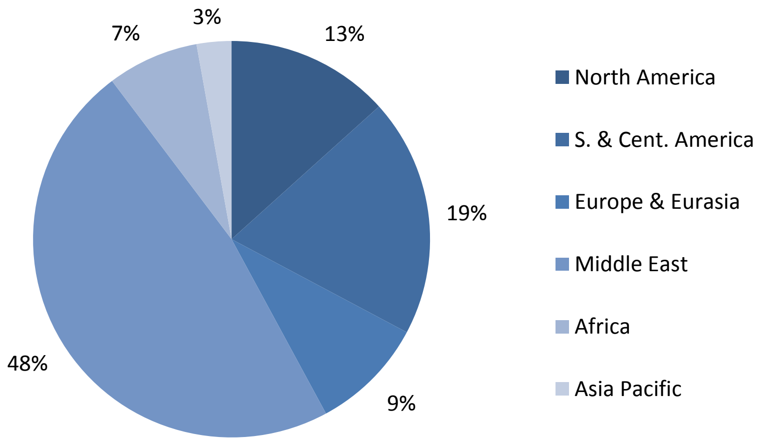


Source: BP Statistical Review of World Energy June 2018.

Worldwide proven oil reserves stood at an estimated 1,697 billion barrels at the end of 2017, sufficient to meet some 50 years of global production at 2017 production levels.

The members of OPEC together held 71.8 percent of total global reserves in 2017. OPEC includes the largest Middle East oil producers, namely Iran, Iraq, Kuwait, Saudi Arabia, Qatar and the UAE, in addition to Algeria, Angola, Congo, Equatorial Guinea, Libya, Nigeria, Gabon, Ecuador, and Venezuela. OPEC has historically played the role of swing producer in the global oil market and its decisions have had considerable influence on oil supply availability and thus international oil prices.[1]

Figure 3 – Distribution of proven world oil reserves 2017



Source: BP Statistical Review of World Energy June 2018.

10.2.2 Oil prices

Oil prices were close to all-time highs for most of 2011, 2012, 2013 and the first half of 2014, with Brent oil trading within a US$ 100-125/bbl range most of the time. However, during the second half of 2014, oil prices declined steeply and in 2015 Brent averaged US$ 54/bbl. Towards the end

[1] BP Statistical Review of World Energy June 2018

of 2015 and into 2016, oil prices decreased further and Brent reached a low of US$ 28/bbl in January 2016. Since then, prices have recovered substantially with Brent averaging US$ 55/bbl in 2017, US$ 72/bbl so far in 2018 and US$ 68/bbl over the past twelve months.

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. As such, it is influenced by global macroeconomic conditions and may experience material fluctuations on the basis of economic indicators and material economic events and geopolitical events. Historically, oil prices have also been heavily influenced by organizational and national policies, most significantly the formation of OPEC and subsequent production policies announced by the organization. The figure below shows Brent oil price development from 1 January 2000 to 6 September 2018.

Figure 4 – Brent oil price, daily from 1 Jan 2000 to 6 Sep 2018

Source: Bloomberg oil price data.

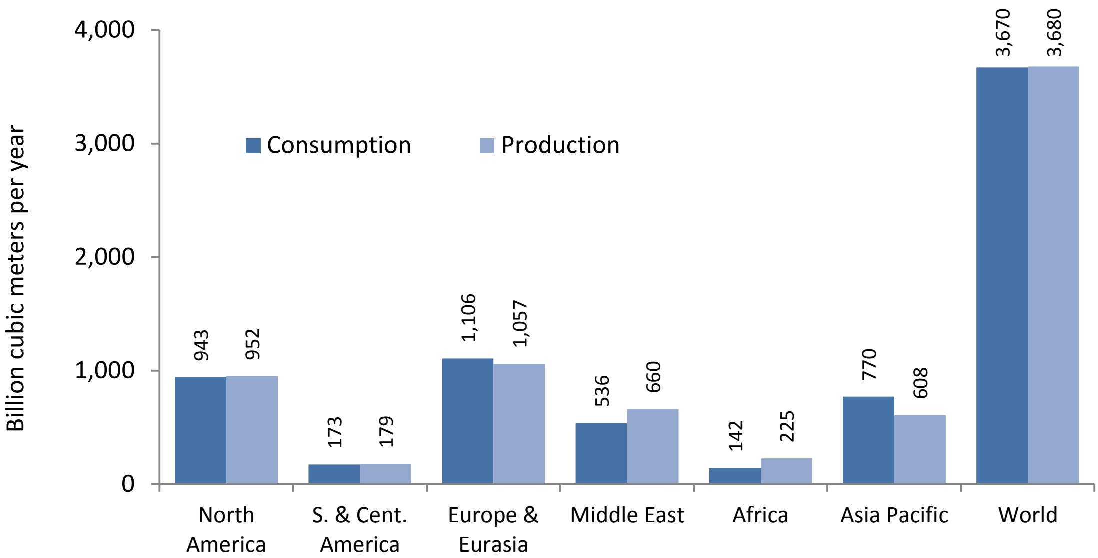
10.3 OVERVIEW OF THE GLOBAL MARKET FOR GAS

Natural gas is typically colorless, odorless and non-toxic at ambient temperatures. It can be found in onshore and offshore reservoirs, either as associated gas in crude oil or condensate or alone as non-associated gas. Natural gas is composed primarily of methane, but may also contain ethane, propane and heavier hydrocarbons. Small quantities of nitrogen, oxygen, carbon dioxide, sulfur compounds and water can also be found in natural gas. It is often termed a premium commodity for its value as both an energy source and as a feedstock for petrochemical products, and because it is relatively clean-burning. As a result, natural gas is used in a variety of ways: for home and business heating, electric power generation, the manufacture of petrochemical products ranging from plastics to fertilizers and intermediate materials, and as a vehicle fuel.

10.3.1 World gas production, consumption and reserves

In 2017, total world consumption of gas was approximately 3,670 billion cubic meters ("bcm") of which Europe and Eurasia, North America and Asia Pacific accounted for approximately 30 percent, 26 percent and 21 percent, respectively. Consumption of gas in the Middle East was approximately 536 bcm in 2017, representing approximately 15 percent of the world total. Production in the Middle East exceeded consumption by 123 bcm.

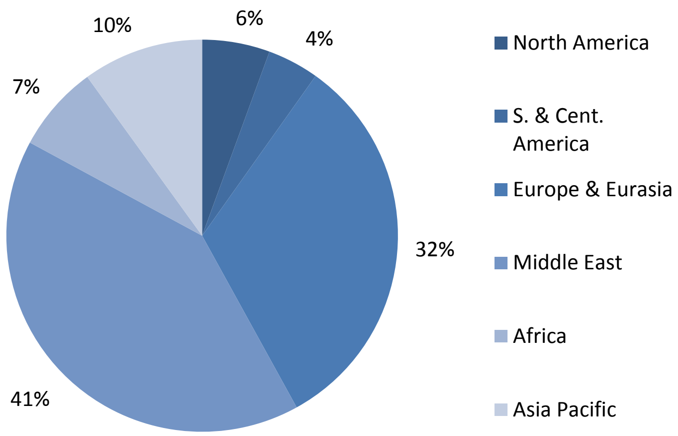
Figure 5 – World gas consumption and production by region, 2017



Source: BP Statistical Review of World Energy June 2018.

Total world proven gas reserves stood at approximately 193 trillion cubic meters at the end of 2017. These reserves are sufficient to meet approximately 53 years of global gas production at 2017 levels. Approximately 41 percent of total world proven gas reserves are located in the Middle East, while Europe and Eurasia contain 32 percent (of which the majority is in Russia and Turkmenistan).

Figure 6 – Distribution of proven world gas reserves, 2017



Source: BP Statistical Review of World Energy 2018.

10.3.2 Gas prices

Because gas is not easily transported, gas prices are not determined by a world-wide market. Gas prices are usually determined regionally, with regions defined by pipeline and LNG transportation networks. There is less correlation between regional gas prices than there is between the prices of various types of oil, but there is correlation between gas prices and the oil price and other energy prices.

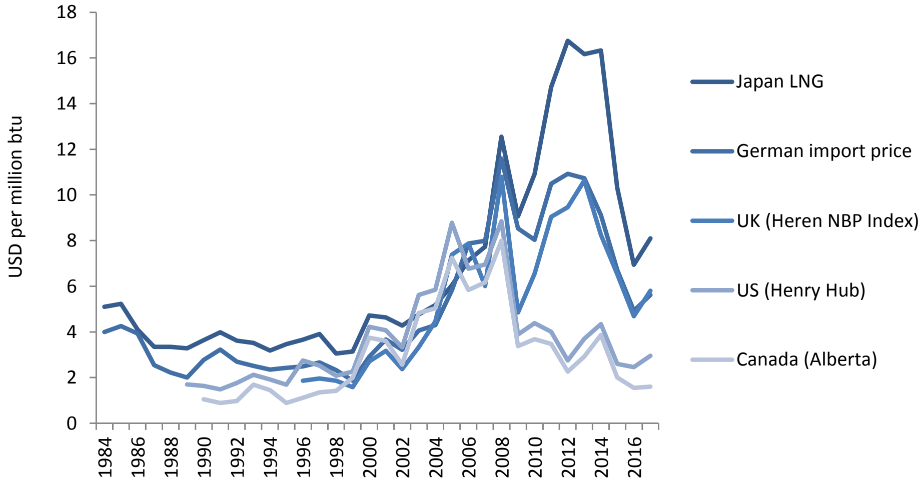
Gas price volatility is significantly higher than oil price volatility. This is primarily due to the fact that gas is more difficult to store than oil, meaning that gas prices are affected by immediate supply and demand within pipeline networks.

Three broad pricing mechanisms exist for gas. The first, mostly seen in international trade and in long-term contracts, involves linking gas to either crude or petroleum product prices. The second pricing mechanism is regulated pricing in domestic markets where governments set fixed prices usually reflecting production and transportation costs. The final mechanism is competitive pricing whereby trading points, often called hubs, are established in major markets and price is determined by supply and demand at these hubs.

The gas market in the U.S. is largely deregulated. There are multiple trading points across the U.S. and Canada, but the most active point is the Henry Hub in Louisiana. In Europe, gas has historically been traded under long- term contracts with pricing linked to diesel and heavy fuel. In recent years, however, an increasing share of European gas volumes have shifted from oil based to hub-based pricing, where gas supply demand dynamics determine the price. Several trading hubs for gas have been established, the most active of which is the National Balancing Point (NBP), in the United Kingdom.

Oil-linked pricing has been prevalent in Asia, where large volumes of gas have been imported in liquefied form under long-term contracts.

Figure 7 – Historical gas prices



Source: BP Statistical Review of World Energy June 2018.

11. BOARD OF DIRECTORS, MANAGEMENT AND EMPLOYEES

11.1 BOARD OF DIRECTORS

11.1.1 Overview

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

The following table sets forth, as the date of this Prospectus, the number of options and shares beneficially owned by each of the Company's directors as of the date of this Prospectus:

Name	Position	Has served since	Term expires	Options held	Shares held
Julien Balkany[1]	Chairman	October 2014	AGM 2019	None	3,116,035
Alexandra Herger	Board member	October 2014	AGM 2019	None	5,950
Garrett Soden	Board member	May 2015	AGM 2019	None	10,008
Torstein Sanness	Board member	May 2015	AGM 2019	None	132,111
Hilde Ådland	Board member	April 2016	AGM 2019	None	7,005

11.1.2 Description of the board members

The Company's Board of Directors consists of the following members:

Julien Balkany – Chairman of the Board

Mr. Julien Balkany, Chairman of the Board, is a French citizen resident in London, has been serving as a managing partner of Nanes Balkany Partners, a group of investment funds. Mr Balkany has been from March 2015 to May 2016 a non-executive Director of Norwegian Energy Company ASA (Noreco), a Norwegian E&P company listed on the Oslo Stock Exchange and focused on the North Sea. Mr. Balkany has been from May 2014 to July 2015 a non-executive Director of Gasfrac Energy Services Inc., a Canadian oil and gas fracking services company. From January 2009 to March 2011, Mr. Balkany served as Vice-Chairman and non-executive Director of Toreador Resources Corp., an E&P company with operations in Continental Europe (France, Turkey, Hungary and Romania) that was dual-listed on the US NASDAQ and Euronext Paris. Mr. Balkany has been a Managing Director at Nanes Delorme Capital Management LLC, a New York based financial advisory and broker-dealer firm, where he executed several hundred million dollars' worth of oil & gas M&A transactions. Before joining Nanes Delorme, Mr. Balkany worked at Pierson Capital and gained significant experience at Bear Stearns. Mr. Balkany studied at the Institute of Political Studies (Strasbourg) and at UC Berkeley. Mr. Balkany is fluent in French, English and Spanish. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

Alexandra Herger, Non-Executive Director

Ms. Alexandra Herger is a US citizen based in Maine, has extensive senior leadership and board experience in worldwide exploration and production for international oil and gas companies. Ms. Herger has 39 years of global experience in the energy industry, currently serving as an Independent director for Tortoise Capital Advisors, CEFs, based in Leawood, Kansas, Tethys Oil based in Stockholm, Sweden, as well as Panoro Energy. Her most recently leadership experience

[1] Held through investment funds Nanes Balkany Partners I LP and Balkany Investments LLC.

was as interim Vice President for Marathon Oil Corporation until her retirement in July 2014. Prior to this position, Ms. Herger was Director of International Exploration and New Ventures for Marathon Oil Company from 2008-2014. Ms. Herger was at Shell International and Shell USA from 2002-2008 Earlier, Mr Herger held senior positions with Enterprise Oil, Hess Corp. and ExxonMobil Corp. Ms. Herger holds a Bachelor's Degree in Geology from Ohio Wesleyan University and post-graduate studies in geology from the University of Houston. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

Garrett Soden, Non-Executive Director

Mr. Garrett Soden has extensive experience as a senior executive and board member of various public companies in the natural resources sector. He has worked with the Lundin Group for over a decade. Mr. Soden is currently President and CEO of Africa Energy Corp., a Canadian oil and gas exploration company focused on Africa. He is also a Non-Executive Director of Etrion Corporation, Gulf Keystone Petroleum Ltd. and Phoenix Global Resources PLC. Previously, he was Chairman and CEO of RusForest AB, CFO of Etrion and PetroFalcon Corporation and a Non-Executive Director of PA Resources AB and Petropavlovsk PLC. Prior to joining the Lundin Group, Mr. Soden worked at Lehman Brothers in equity research and at Salomon Brothers in mergers and acquisitions. He also previously served as Senior Policy Advisor to the U.S. Secretary of Energy. Mr. Soden holds a BSc honours degree from the London School of Economics and an MBA from Columbia Business School. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

Torstein Sanness, Non-Executive Director

Mr. Torstein Sanness is a Norwegian Citizen residing in Norway has extensive experience and technical expertise in the oil and gas industry. Mr. Sanness became the Chairman of Lundin Petroleum Norway in April 2015. Prior to this position Mr. Sanness was Managing Director of Lundin Petroleum Norway from 2004 to April 2015. Under his leadership Lundin Norway has added net discovered resources of close to a billion boe to its portfolio through the discoveries of among others E. Grieg and Johan Sverdrup. Before joining Lundin Norway Mr. Sanness was Managing Director of Det Norske Oljeselskap AS (wholly owned by DNO at the time). From 1975 to 2000, Mr. Sanness was at Saga Petroleum until its sale to Norsk Hydro and Statoil, where he held several executive positions in Norway as well as in the US, including being responsible for Saga's international operations and entry into Libya, Angola, Namibia, and Indonesia. Mr. Sanness is a graduate of the Norwegian Institute of Technology in Trondheim where he obtained a Master of Engineering. Mr. Sanness is also a director of Lundin Petroleum, IPC, TGS and Magnora. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

Hilde Ådland, Non-Executive Director

Mrs. Hilde Ådland is a Norwegian citizen, and has leadership experience in field development, engineering, commissioning, and field operations. Mrs. Ådland is currently Asset Manager for the operated Gjøa field for Neptune Energy Norge AS (previously Engie E&P Norge AS/GDF SUEZ E&P Norge AS). She held several senior positions with Engie, GDF Suez and Gaz de France in Norway including production and development manager and senior facility engineer. Prior to joining GDF in 2008, she spent 12 years with Statoil in a number of senior engineering and operational roles, including Offshore Installation Manager, and 5 years with Kvaerner. In autumn 2015 she was also elected chairman in the Operation Committee within the Norwegian Oil and Gas Association. She has a BA's degree in chemical engineering and a Master's degree in process engineering. *Business address: Vestre Svanholmen 6, Sandnes, P.O. Box 242, 4066 Stavanger, Norway.*

11.1.3 Corporate Governance recommendation compliance

The composition of the Board of Directors is in accordance with the recommendation of the Norwegian Code of Practice for Corporate Governance dated 17 October 2018 (the "Corporate Governance Code").

11.2 MANAGEMENT

11.2.1 Overview

The management is responsible for day-to-day management of the Company's operations in accordance with the instructions set out by the Board of Directors. Among other things, the CEO of a Norwegian public company is obligated to ensure that the company's accounts are kept in accordance with existing Norwegian legislation and regulations, and that the assets of the company are managed responsibly. In addition, at least once a month the CEO of a Norwegian public company must brief the board of directors about the company's activities, position and operating results.

The following table sets forth, as the date of this Prospectus, the number of options and shares beneficially owned by each of the Company's management as of the date of this Prospectus:

Name	Position	RSUs held	Shares held
John Hamilton	CEO	362,972	167,912
Qazi Qadeer	CFO	146,335	77,062
Richard Morton	Technical Director	129,669	122,425

The outstanding share RSUs were issued under the employee share options plan in the year 2017 and 2018 and the exercise price is NOK 0.05 (which may be subject to adjustments under the plan rules).

11.2.2 Description of the management team

John Hamilton, Chief Executive Officer

John Hamilton, Chief Executive Officer, has considerable experience from various positions in the international oil and gas industry. Prior to joining Panoro Energy as Chief Executive Officer in May 20015, John was Chief Executive Officer of UK AIM listed President Energy PLC, a Latin American focused exploration company, which opened up a new onshore basin in Paraguay. Before joining President, John was Managing Director of Levine Capital Management, and oil and gas investment fund. He was also Chief Financial Officer of UK FTSE 250 listed Imperial Energy PLC, until its sale for over US$ 2 billion in 2008. John also spent 15 years with ABN AMRO Bank in Europe, Africa, and the Middle East. The majority of his time with ABN AMRO was spent in the energy group, with a principal focus on financing upstream oil and gas. John has a BA from Hamilton College in New York, and an MBA from the Rotterdam School of Management and New York University. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

Qazi Qadeer, Chief Financial Officer

Qazi Qadeer, Chief Financial Officer, is a Chartered Accountant with a Fellow membership of Institute of Chartered Accountants of Pakistan. Qazi joined Panoro at its inception in 2010 as Group Finance Controller. Previously Qazi has worked for PriceWaterhouseCoopers in Karachi, Pakistan and briefly served as Internal audit manager in Pak-Arab Refinery before relocating to London, where he has spent more than five years with Ernst & Young's energy and extractive industry assurance practice; working on various projects for large and small oil & gas and mining companies. He has worked on several high profile projects including the divestment of BP plc's chemicals business in 2005 and IPO of Gem Diamonds Limited in 2006. He is a British citizen and resides in London, UK. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

Richard Morton, Technical director

Richard Morton, Technical Director, has 25 years of experience in exploration, production, development and management in the oil and gas industry. Originally a highly qualified geophysicist, he has expanded his portfolio of skills progressively into operational and asset management. He has worked in a number of challenging contracting and operating environments, including as Centrica Energy's Exploration Manager for Nigeria. He has been with Panoro Energy since 2008 with responsibilities for project and technical management of Panoro's African exploration and development assets. Richard obtained a B.Sc. in Physics from Essex University in 1989 and went on to complete a M.Sc. in Applied Geophysics from the University of Birmingham the following year. He is a British citizen and resides in London, UK. *Business address: 78 Brook Street, London W1K 5EF, United Kingdom.*

11.3 OTHER DIRECTORSHIPS AND MANAGEMENT POSITIONS

Over the five years preceding the date of this document, the member of the Board and the senior management hold or have held the following directorships (apart from their directorships of the Company and its subsidiaries) and/or partnerships:

Board of Directors:	**Current directorships and senior management positions**	**Previous directorships and senior management positions last five years**
Julien Balkany	Sarmin Bauxite Ltd (Board member) Pan-African Diamonds Ltd (Board member) Nanes Balkany Partners I LP (Managing Partner) Balkany Investments LLC (Managing Member) Skyn Iceland LLC (Director)	Norwegian Energy Company ASA (Board member) Gasfrac Energy Services Inc. (Board member and Vice Chairman)
Alexandra Herger	Tethys Oil (Board Members) Tortoise Capital Advisors – Closed End Funds (Board member)	Marathon Oil Corp (Vice President Global Oil Exploration)
Garrett Soden	Africa Energy Corp. (President & CEO) Etrion Corporation (Board member) Gulf Keystone Petroleum Ltd (Board member) Phoenix Global Resources plc. (Board member)	RusForest AB (Chairman) PA Resources (Board member) Petropavlovsk plc (Board member)
Torstein Sanness	TGS Nopec Geophysical Company ASA (Board member) Magnora ASA (Board member) Lundin Petroleum AB (Board member) International Petroleum Corp. (Board member)	Lundin Norway AS (Managing Director) Lundin Norway AS (Chairman) Ocean Industry Forum (Board member)
Hilde Ådland	Neptune Energy Norge AS (Asset Manager Gjøa) Magnora ASA (Board member)	GDF SUEZ/Engie E&P Norge AS (Asset manager Gjøa)

No board member has private interests of relevance and there are no other understandings or agreements with major shareholders in respect of selection of board members.

Management:	Current directorships/partnerships	Previous directorships/partnerships
John Hamilton	Magnora ASA (Board member)[1]	IGAS PLC (Director) President Energy PLC (CEO) President Energy (UK) Limited (Director) President Energy Paraguay Limited (Director) President Energy Pirity Limited (Director) President Energy Holding UK Limited (Director) Levine Capital Management Limited (Managing Director)
Qazi Qadeer	None	None
Richard Morton	None	Zebra Energy Limited (Director)

11.4 THE NOMINATION COMMITTEE

The Company has a nomination committee consisting of 3 members elected by the 2018 annual general meeting for a two-year period. The Nomination Committee currently consists of Eric Nasby (chairperson), Fredrik Thoresen and Erik Sneve. All members of the committee are independent of the Board of Directors and the day-to-day management. The nomination committee's duties are to propose to the general meeting shareholder elected candidates for election to the board of directors, and to propose remuneration to the board. The annual general meeting may adopt procedures for the nomination committee.

11.5 AUDIT COMMITTEE AND COMPENSATION COMMITTEE

The Board has an Audit Committee, consisting of 5 members. The members are independent of the executive management. The purpose of the committee is to assist the Board of Directors to serve as an independent, objective check and balance in the Company's financial reporting and internal control. The Audit Committee currently consists of Garrett Soden (chair), Torstein Sanness, Alexandra Herger, Hilde Ådland and Julien Balkany.

Its responsibilities include:

- The integrity of the financial statements of the Company, including the audited annual and the unaudited quarterly financial statements.
- The independence, qualifications, performance and compensation of the Company's independent auditors.
- The performance of the Company's internal audit function.

[1] Subject to approval at a general meeting scheduled for 18 December 2018

- The Company's compliance with legal and regulatory policies.

The Board further appoints a Compensation Committee, currently consisting of 5 members. The members are to be independent of the executive management. The Compensation committee currently consists of Torstein Sanness (chair), Garrett Soden, Alexandra Herger, Hilde Ådland and Julien Balkany.

The Compensation Committee meets regularly, and the objective of the committee is to determine the remuneration strategy for the Company and to consider the compensation for the Company's CEO. The Compensation Committee presents its recommendations to the Board, whereby the Board of Directors decide upon the remuneration of the CEO. Remuneration to the CEO shall be at market terms and decided by the Board and made official at the annual general meeting every year. The Board presents their declaration on determination of salaries and other remuneration to the executive management for approval by the annual general meeting.

11.6 CONFLICT OF INTERESTS

The are no conflict of interest or potential conflict of interest between any duties to the Company, of the members of the Board of Directors or the senior management, and their private interests or other duties. There are no family relations between any of the members of the Board of Directors or members of senior management.

11.7 CONVICTIONS FOR FRAUDULENT OFFENCES, BANKRUPTCY, ETC.

None of the members of the Board of Directors or the Management have during the last five years preceding the date of this Prospectus:

- Any convictions in relation to indictable offences or convictions in relation to fraudulent offences;
- received any official public incrimination and/or sanctions by any statutory or regulatory authorities (including designated professional bodies) or ever been disqualified by a court from acting as a member of the administrative, management or supervisory bodies of a company or from acting in the management or conduct of the affairs of any company; or
- been declared bankrupt or been associated with any bankruptcy, receivership or liquidation in his capacity as a founder, director or senior manager of a company.

11.8 REMUNERATION AND BENEFITS

11.8.1 Remuneration of the Board and Management

The remuneration of the members of the Board is determined on a yearly basis by the Company at its annual general meeting. The directors may also be reimbursed for, inter alia, travelling, hotel and other expenses incurred by them in attending meetings of the directors or in connection with the business of Panoro Energy. A director who has been given a special assignment, besides his normal duties as a director of the Board, in relation to the business of Panoro Energy may be paid such extra remuneration as the directors may determine.

Board compensation for 2017 and 2016 was as follows:

USD 000	2017	2016
Julien Balkany (Chairman of the Board of Directors)	68	66
Alexandra Herger	39	38
Garrett Soden	39	38
Torstein Sanness	39	38
Hilde Ådland (i)	39	28
Total	**224**	**208**

The Chairman of the Board of Directors' annual remuneration is NOK 450,000. The remaining Directors' annual remuneration is NOK 225,000. All Board Members also form the Audit Committee and Remuneration Committee for which they each receive NOK 50,000 annually per committee. No loans have been given to, or guarantees given on the behalf of, any members of the Management Group, the Board or other elected corporate bodies.

(i) Pursuant to an Extraordinary General Meeting held on March 2, 2016, Hilde Ådland was elected to the Board of Directors with an effective date of April 1, 2016 to take the Board composition to five members.

No loans have been given to, or guarantees given on the behalf of, any members of the Management Group, the Board or other elected corporate bodies.

The annual general meeting held 24 May 2018 approved remuneration for the Board for the period up to the annual general meeting in 2019 of NOK 460,000 to the chairperson and NOK 240,000 for each other Board member. Members of the Remuneration Committee and the Audit Committee will each receive NOK 50,000 annually, as determined by the annual general meeting held 24 May 2018.

Management compensation for the financial year ended 31 December 2017 and the financial year ended 31 December 2016, respectively, was as follows:

2017	Short term benefits						
USD 000 (unless stated otherwise)	Salary	Bonus	Benefits	Pension costs	Total	Number of RSUs awarded in 2017	Fair value of RSUs expensed
John Hamilton, CEO	380	94	8	36	518	200,000	64
Qazi Qadeer, CFO	227	43	4	22	296	100,000	32
Richard Morton, Technical Director	239	45	4	23	311	80,000	26
Total	**846**	**182**	**16**	**81**	**1,125**	**380,000**	**122**

2016	Short term benefits						
USD 000 (unless stated otherwise)	Salary	Bonus	Benefits	Pension costs	Total	Number of RSUs awarded in 2016	Fair value of RSUs expensed
John Hamilton, CEO	372	74	7	37	490	100,000	21
Qazi Qadeer, CFO	225	45	4	22	296	50,000	10
Richard Morton, Technical Director	239	24	4	24	290	40,000	8
Total	**836**	**143**	**15**	**83**	**1,076**	**190,000**	**39**

11.8.2 Benefits upon termination of employment

Under the terms of employment, the CEO, CFO and the Technical Director is required to give at least six months written notice prior to leaving Panoro.

Per the respective terms of employment, the CEO is entitled to 12 months of base salary in the event of a change of control; whereby a tender offer is made or consummated for the ownership of more than 50% or more of the outstanding voting securities of the Company; or the Company is merged or consolidated with another corporation and as a result of such merger or consolidation less than 50.1% of the outstanding voting securities of the surviving entity or resulting corporation are owned in the aggregate by the persons by the entities or persons who were shareholders of the Company immediately prior to such merger or consolidation; or the Company sells substantially all of its assets to another corporation that is not a wholly owned subsidiary. Other members of the management team are not entitled to such remuneration at change of control.

Under the share options plan should such an event occur, all outstanding share options will also vest immediately and the Company may have the right to terminate the options by:

- Compensating the difference between the fair market value of the options and the exercise value; or
- Replacing the options with new options in the acquiring company; or
- Compensating the holder of the options with an amount of cash equivalent to the fair market value of the options, using the full contractual life of the option when calculating the fair market value.

11.8.3 Pension obligations and option schemes

11.8.3.1 Pension schemes

For the year ended 31 December 2017, the Company had an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("Lov om obligatorisk tjenestepensjon"). The Company contributes to an external defined contribution scheme and therefore no pension liability is recognized in the statement of financial position.

In the UK, the Company's subsidiary that employs the staff, contributes a fixed amount per Company policy in an external defined contribution scheme.

Pension contributions are governed by law in Tunisia and a fixed percentage of employees gross salaries are paid over to a state run pension scheme without any further liability to the employing company.

As such, no pension liability is recognised in the statement of financial position in relation to Company's subsidiaries either.

Pension contributions are paid on a monthly and quarterly basis and as of 30 September 2018, there is no liability of the Company or its subsidiaries towards staff pensions.

11.8.3.2 Restricted Stock Unit scheme

At the annual general meeting held 27 May 2015, an employee incentive scheme was approved where under the Company may issue restricted stock units ("**RSUs**") to executive employees. At the annual general meeting held 24 May 2018, the program was renewed.

Awards under the scheme will normally be considered one time per year and grant of share based incentives will in value (calculated at the time of grant) be capped to 100% of the annual base salary for the CEO and 50% of the annual base salary for other members of the executive management.

One RSU will entitle the holder to receive one share of capital stock of the Company against payment in cash of the par value for the share. The total number of RSUs available for grant under the RSU program during the period from the 2015 annual general meeting and up to the annual general meeting in 2018 was not to exceed 5% of the number of shares outstanding as per the date of the 2015 annual general meeting (at which point in time the total number of shares was 234,545,786). The total number of RSUs available for grant under the program approved at the 2018 annual general meeting is not to exceed 5% of the shares issued at 24 May 2018, which results in a maximum of 2,125,109 RSUs being available up to the annual general meeting in 2021.

Grant of RSUs will be subject to a set of performance metrics with threshold and factors reviewed annually by the Board of Directors. Such metrics will be set as objectives based on sustained performance results including mostly share price increases and achievement of specific financial performance measures related to a group of oil and gas exploration and production peers that has been defined and adopted by a committee established by the Board. The annual criteria applied for grants of RSUs to members of the executive team during the previous financial year will, unless they contain confidential and company sensitive targets, be disclosed in the Company's annual remuneration statement pursuant to section 6-16a of the Public Limited Companies Act.

Vesting of the RSUs is time based. The standard vesting period is three years, where 1/3 of the RSUs vest after one year, 1/3 vest after two years, and the final 1/3 vest after three years after grant, unless the Board decides otherwise for specific grants. RSUs vest automatically at the respective vesting dates and the holder will be issued the applicable number of shares as soon as possible thereafter.

In June 2017, 420,000 Restricted Share Units (RSU) were awarded to key employees under the Company's 2015 RSU scheme. During the year ended 31 December 2017, 420,000 RSUs had been granted (200,000 granted as at 31 December 2016) and 66,666 RSUs were vested and settled. A total of 553,334 RSUs were outstanding as of 31 December 2017 and the awards related to permanent employees of the Company. With the exception of 66,666 RSUs that were vested and automatically exercised and settled in cash, no RSUs were terminated or expired during the 2017 financial year. The weighted average exercise price of the RSUs granted during the year was NOK 0.05 per unit.

On 6 August 2018, a total of 376,333 RSUs were awarded to key employees under the Company's 2018 RSU scheme. The weighted average exercise price of the RSUs granted was NOK 0.05 per unit. At the same time, 206,667 RSUs as awarded under the Company's 2015 RSU scheme were exercised and settled. Subsequent to this date, 14,277 RSUs were terminated.

As per the date of this Prospectus, a total of 346,667 RSUs under the 2015 scheme and 362,056 RSUs under the 2018 scheme are outstanding.

11.8.4 Loans and Guarantees

No loans have been given to, or guarantees given on the behalf of, any members of the Management Group, the Board or other elected corporate bodies.

11.9 EMPLOYEES

As of the date of this Prospectus, the Company has 31 employees, of which five are based in London and the remaining are based in Tunisia. Details on the key management personnel are covered in section 11.2.2 whereas the remaining employees perform support services of accounting and office administration tasks to the Company. The table below illustrates the development in number of employees over the last years for the Company, as per the end of each calendar year 2015, 2016 and 2017 and at 30 September 2018.

Year	As of date	Total
2018	30 September	31
2017	31 December	5
2016	31 December	5
2015	31 December	5

12. SHARE CAPITAL AND SHAREHOLDER MATTERS

The following description includes certain information concerning the Company's share capital, a brief description of certain provisions contained in the Company's Articles of Association and Norwegian law in effect as of the date of this Prospectus. Any change in the Articles of Association is subject to approval by a general meeting of shareholders. This summary does not intend to be complete and is qualified in its entirety by the Company's Articles of Association and Norwegian law.

12.1 SHARE CAPITAL AND SHARES

12.1.1 General

Panoro is a public limited liability company organized under the laws of Norway and subject to the Norwegian Public Limited Liability Companies Act, with its registered office at c/o Michelet & Co Advokatfirma AS, Grundingen 3, 0250 Oslo, Norway. The legal and commercial name of the Company is Panoro Energy ASA. The Company was incorporated on 28 April 2009, and registered with the Norwegian Register of Business Enterprises on 6 May 2009 with organizational number 994 051 067.

Panoro's independent auditor is Ernst & Young, and their business address is Dronning Eufemias gate 6, 0191 Oslo, Norway. Ernst & Young is a member of Den Norske Revisorforening (the Norwegian Institute of Public Accountants).

12.1.2 Share capital

As of the date of this Prospectus, Panoro Energy's registered share capital is NOK 3,119,380 divided into 62,387,600 Shares each with a nominal value of NOK 0.05. All the Shares are authorised and fully paid.

The Company has one class of shares, each Share carrying equal shareholder rights, including voting rights at general meetings. The Company's articles of association does not provide for limitations on the transferability or ownership of Shares.

The Shares have been created under the Norwegian Public Limited Liability Companies Act and registered in book-entry form with the VPS under the International Securities Identification Number (ISIN) NO 001 0564701. The registrar for the Shares is Nordea Bank Norge ASA, Registrars department, Essendrops gate 7, 0368 Oslo, Norway.

12.1.3 Treasury Shares

As of the date of this Prospectus, Panoro Energy does not own any treasury shares.

12.1.4 Warrants, convertible loans and authorisations to issue new Shares

At the date of this Prospectus, the Company has granted a total of 708,723 outstanding RSUs, each giving the holder the right, subject to certain conditions, to subscribe one share in the Company against payment of NOK 0.05 per share. None of the Company's its subsidiaries has issued any options, warrants, convertible loans or other instruments that would entitle a holder of any such instrument to subscribe for any shares in the Company or its subsidiaries. Further, neither the Company nor any of its subsidiaries has issued subordinated debt or transferable securities other than the Shares and the shares in its subsidiaries which will be held, directly or indirectly, by the Company. Outstanding authorisations

In the annual general meeting held 24 May 2018 the Board of Directors was granted two authorisations to increase Panoro Energy's share capital through issuance of new shares and one authorisation to acquire treasury shares. Further, at the EGM, the Board of Directors was granted a renewal of one of the mentioned authorisations to issue new shares. The details are set out below.

Authorization to the Board to conduct capital increases by way of share issue under the Company's incentive program

"The Company's Board is authorized to increase the share capital, on the following conditions:

1. The share capital may, in one or more rounds, be increased by a total of up to NOK 106,256 by the issuance of up to 2,125,120 new shares in the Company.

2. The authorization may be used to issue shares to the Company's employees under the Company's incentive program.

3. The authorization shall be valid until the ordinary general meeting in 2019, but no later than until 30 June 2019.

4. The shareholders' pre-emption for subscription of shares may be set aside.

5. The authorization includes the increase of the share capital in return for contributions in kind or the right to incur on the assumptions of special obligations of the Company.

6. The Board is authorized to alter the Articles of Association implied by the share capital increase(s).

7. The authorization does not include decision on merger."

Authorization to the Board to conduct capital increases by way of share issues for other purposes

"The Company's Board is authorized to increase the share capital, on the following conditions:

1. The share capital may, in one or more rounds, be increased by a total of up to NOK 212,510.95 by the issuance of up to 4,250,219 new shares in the Company.

2. The authorization may be used to issue shares as consideration for acquisitions within the Company's ordinary business sectors or in connection with equity increases.

3. The authorization shall be valid until the ordinary general meeting in 2019, but no later than until 30 June 2019.

4. The shareholders' pre-emption for subscription of shares may be set aside.

5. The authorization includes the increase of the share capital in return for contributions in kind or the right to incur on the assumptions of special obligations of the Company.

6. The Board is authorized to alter the Articles of Association implied by the share capital increase(s).

7. The authorization does include decision on merger."

As of the date of this Prospectus, the Board of Directors has used the first of the above authorizations to issue 55,185 new shares as part of exercise of RSUs, and further used 100% of the second authorization for the purpose of the private placement announced in June 2018. Consequently, the EGM approved to substantially renew this authorisation as follows:

Authorization to the Board to conduct capital increases by way of share issues for other purposes

"The Company's Board is authorized to increase the share capital, on the following conditions:

1. The share capital may, in one or more rounds, be increased by a total of up to NOK 234,038 by the issuance of up to 4,680,760 new shares in the Company.

2. The authorization may be used to issue shares as consideration for acquisitions within the Company's ordinary business sectors or in connection with equity increases.

3. The authorization shall be valid until the ordinary general meeting in 2019, but no later than until 30 June 2019.

4. The shareholders' pre-emption for subscription of shares may be set aside.

5. The authorization includes the increase of the share capital in return for contributions in kind or the right to incur on the assumptions of special obligations of the Company.

6. The Board is authorized to alter the Articles of Association implied by the share capital increase(s).

7. The authorization does include decision on merger."

Authorization to acquire treasury shares

"1. The Board of Directors is authorized to acquire shares in the Company. The shares are to be acquired at market terms in or in connection with a regulated market where the shares are traded.

2. The shares may be disposed of either to meet obligations under employee incentive schemes, as part of consideration payable for acquisitions made by the Company, as part of consideration for any mergers, demergers or acquisitions involving the Company, to raise funds for specific investments, for the purpose of paying down loans (including convertible loans), or in order to strengthen the Company's capital base. The Board is free to choose the method of disposal considered expedient for such purposes.

3. The maximum face value of the shares which the Company may acquire pursuant to this authorization is in total NOK 212,500. The minimum amount which may be paid for each share acquired pursuant to this power of attorney is NOK 1, and the maximum amount is NOK 100.

4. The authorization comprises the right to establish pledge over the Company's own shares.

5. This authorization is valid from registration with the Norwegian Register of Business Enterprises and until and including 30 June 2019."

As of the date of this Prospectus, the Board of Directors does not have any authorisations to issue independent subscription rights or convertible loans. The shares issued pursuant to the Private Placement have been issued in accordance with resolutions made by the EGM.

12.1.5 Transferability and foreign ownership

There are no restrictions on trading in the Company's Shares and no restrictions on foreign ownership of the Company's Shares.

12.1.6 Legislation and rights attached to the Shares

Reference is made to the review of legislation and rights attached to the Company's Shares in Section 12.4 "The Articles of Association and general shareholder matters".

12.1.7 Mandatory offers

Please see Section 12.5.7 "Mandatory offer requirement" which outlines the legislation on mandatory offers applicable to Norwegian companies listed on Oslo Børs. The Company has not been subject to any public take-over bids the last 12 months.

12.2 HISTORICAL DEVELOPMENT IN SHARE CAPITAL AND NUMBER OF SHARES

Below is a table showing the development in the number of Shares and the share capital of Panoro Energy since incorporation on 6 May 2009 until the date of the Prospectus (all figures in NOK).

Year	Type of change	Change in share capital	Subscription price	Total issued share capital	No of shares
6 May 2009	Incorporation	100,000	1,000	100,000	100
7 January 2010	Capital increase	900,000	1,000	1,000,000	1000
7 June 2010	Capital reduction pre Demerger	1,000,000		0	0

7 June 2010	Capital Increase upon completion of Demerger	68,372,651.79	12.5958	68,372,651.79	46,815,456
7 June 2010	Capital Increase	22,320,203.09	12.5958	90,692,854.88	62,098,328
29 June 2010	Capital Increase	21,769,444.62	12.5958	112,426,299.50	76,979,440
29 June 2010	Capital increase (completion of Merger)	126,977,783.78	12.5958	239,440,083.25	163,947,081
15 February 2011	Capital increase (Private Placement)	23,944,008.18	7.80	263,384,091.43	180,341,789
1 March 2011	Capital Increase (Private Placement)	79,019,251.47	7.80	342,403,342.90	234,447,081
1 March 2011	Capital Increase (Repair Issue)	144,155.87	7.80	342,547,498.77	234,545,786
27 May 2015	Capital reduction (by reduction of par value)	341,374,769.84	n/a	1,172,728.93	234,545,786
8 March 2016	Capital increase (Private Placement)	833,333.33	0.42	2,006,062.26	401,212,452
8 April 2016	Capital increase (Repair offering)	119,047.50	0.42	2,125,109.76	425,021,952
27 May 2016	Capital increase (Share merger 10:1)	0.04	0.05	2,125,109.80	42,502,196
2 August 2018	Capital increase (Private placement)	212,510.95	12.82	2,337,620.75	46,752,415
24 August 2018	Capital increase (Employee incentive shares)	2,759.25	0.05	2,340,380	46,807,600
6 December 2018	Capital increase (Private Placement)	779,000	16.10	3,119,380	62,387,600

Apart from the table above, there have not been any changes in the Company's share capital since the Company's incorporation. Accordingly, as of 1 January 2016, the Company had a total of 401,212,452 shares of 234,545,786 each with a nominal value of NOK 0.005, as of 1 January 2017 and 1 January 2018 42,502,196 shares each with a nominal value of NOK 0.05.

12.3 MAJOR SHAREHOLDERS

The 20 largest shareholders in Panoro Energy ASA as at 14 December 2018 are shown in the table below:

#	Shareholder	Shareholding	Share %
1	F2 FUNDS AS	3,674,229	5.89
2	SPAREBANK 1 MARKETS MARKET-MAKING	2,795,031	4.48
3	J.P. Morgan Securiti A/C CUSTOMER SAFE KE	2,650,444	4.25
4	DNO ASA	2,641,465	4.23
5	SKANDINAVISKA ENSKIL	2,484,472	3.98
6	SUNDT AS	1,614,906	2.59
7	Danske Invest Norge	1,590,785	2.55

#	Shareholder	Shareholding	Share %
8	HORTULAN AS	1,446,578	2.32
9	STOREBRAND VEKST VER JPMORGAN EUROPE LTD,	1,192,247	1.91
10	SPAREBANK 1 MARKETS MEGLERKONTO	1,064,174	1.71
11	KLP AKSJENORGE	938,462	1.50
12	MATHIAS HOLDING AS PER MATHIAS AARSKOG	848,447	1.36
13	PREDATOR CAPITAL MAN	796,024	1.28
14	PARETO SECURITIES AS EMISJONSKONTO INNLAN	768,769	1.23
15	KOMMUNAL LANDSPENSJO	705,203	1.13
16	ALDEN AS	696,894	1.12
17	KAMPEN INVEST AS	624,223	1.00
18	NORDNET LIVSFORSIKRI	600,238	0.96
19	SVOREN STEINAR	594,000	0.95
20	Nordnet Bank AB	576,643	0.92

In accordance with the disclosure obligations under the Norwegian Securities Trading Act, shareholders acquiring ownership to or control over 5% or more of the share capital of a company listed on Oslo Børs must notify the stock exchange immediately. The table above shows the percentage held by such notifiable shareholders.

All Shares carry equal voting rights and the major shareholders in Panoro Energy do not have different voting rights. Each Share of Panoro Energy entitles one vote.

The Company is not aware of any arrangements that may result in, prevent or restrict a change of control of the Company.

12.4 THE ARTICLES OF ASSOCIATION AND GENERAL SHAREHOLDER MATTERS

12.4.1 The Company's objects and purpose

The Articles of Association of the Company are included as Appendix 1 to this Prospectus. According to Section 2 of the Articles of Association, the Company's business shall consist of exploration, production, transportation and marketing of oil and natural gas and exploration and/or development of other energy forms, sale of energy as well as other related activities. The business might also involve participation in other similar activities through contribution of equity, loans and/or guarantees.

12.4.2 The General Meeting of shareholders

The following matters will be considered and decided by the annual general meeting:

1. Approval of the profit and loss statement and balance sheet, including application of the profit for the year or coverage of the loss for the year.
2. Election of board of directors and auditor, and determination of their remuneration.
3. Other issues which pursuant to law or the articles of association are to be decided by the annual general meeting.

If documents that shall be considered at the general meeting are made available to the shareholders on the Company's website, the Companies Act request to send these documents to shareholders does not apply. This shall also apply for documents that, pursuant to law or regulations, shall be included in or attached to the notice of the general meeting. A shareholder may nevertheless upon request to the Company have the documents that shall be considered at the general meeting sent free of charge by mail.

The annual general meeting and the extraordinary general meeting is called with a three week notice period. Registrations for the Company's general meetings must be received at least five calendar days before the meeting is held.

12.4.3 The Board of Directors

Pursuant to the Section 5 of the Articles of Association, the board of directors shall consist of 3 to 8 members.

12.4.4 The Company's signature

Pursuant to the Section 6 of the Articles of Association, the power to sign for the company is exercised by the chairman of the board alone or by two board members jointly.

12.4.5 The Nomination Committee

Pursuant to the Section 8 of the Articles of Association, the Company shall have a nomination committee consisting of two or three members to be elected by the annual general meeting for a term of two years. The majority of the nomination committee shall be independent of the board of directors and the day to day management. The nomination committee's duties are to propose to the general meeting shareholder elected candidates for election to the board of directors, and to propose remuneration to the board. The annual general meeting may adopt procedures for the nomination committee.

12.4.6 Voting rights and other shareholder rights

Panoro Energy has one class of shares, and each Share carry equal voting rights at the general meeting. The Articles of Association do not contain stricter restrictions for changing of the rights of the holders of the Shares than those which follow from the Public Limited Liability Companies Act.

As a general rule, resolutions that shareholders are entitled to make pursuant to Norwegian law or the Company's Articles of Association, requires approval by a simple majority of the votes cast. In the case of election of directors to the Board, the person who obtains the most votes is elected to fill the vacant position. However, as required under Norwegian law, certain decisions, including resolutions to waive pre-emptive rights in connection with any issue of shares, convertible bonds, warrants etc., to approve a merger or demerger, to amend the Company's Articles of Association, to authorise an increase or reduction in the share capital, to authorise an issuance of convertible loans or warrants or to authorise the Board to purchase the Company's own 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 shareholders' meeting. Further, Norwegian law 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 of all the holders of such shares or class of shares as well as the majority required for amendments of the Company's Articles of Association. Decisions that (i) would reduce any existing shareholder's right in respect of dividend payments or other rights to the assets of the Company or (ii) restrict the transferability of the shares require a majority vote of at least 90% of the share capital represented at the general meeting in question as well as the majority required for amendments to the Company's Articles of Association. Certain types of changes in the rights of shareholders require the consent of all shareholders affected thereby as well as the majority required for amendments to the Company's Articles of Association. The Articles of Association of the Company do not contain conditions that are more significant than required by the Norwegian Public Limited Liability Companies Act, including with regard to (i) what action is necessary to change the rights of holders of the Shares, and (ii) changes in capital.

In general, in order to be entitled to vote, a shareholder must be registered as the beneficial owner of Shares in the share register kept by the VPS or provide proof of its beneficial ownership.

Beneficial owners of Shares that are registered in the name of a nominee may not be entitled to vote under Norwegian law unless such Shares are re-registered in the name of the beneficial owner, nor are any persons who are designated in the register as holding such Shares as nominees entitled to vote such Shares.

Readers should note that there are varying opinions as to the interpretation of Norwegian law in respect of the right to vote nominee-registered shares. For example, Oslo Børs has in a statement on 21 November 2003 held that in its opinion "nominee-shareholders" may vote in general meetings if they prove their actual shareholding prior to the general meeting.

Under the Public Limited Companies Act shareholders will have preferential rights to subscribe for new securities issued by the Company, unless such rights are waived with 2/3 majority.

A shareholder will have right to a share in the profits of the Company that are distributed as dividend, as well as any surplus following liquidation of the Company. There is no time limit after which entitlement to dividends lapses under the Norwegian Public Limited Companies Act or the Company's articles of association. Furthermore, there are no dividend restrictions for non-resident shareholders. See section 13 "Norwegian taxation" for a description of the Norwegian tax rules that apply to dividend paid to Norwegian and foreign shareholders.

The shares are not subject to redemption rights with the exemption provided for below under Section 12.5.8 "Compulsory Acquisition". There are no conversion provisions applicable to the Shares.

12.4.7 Additional Issuances and Preferential Rights

If Panoro issues any new shares, including bonus share issues, its Articles of Association must be amended, which requires the same vote as other amendments to its Articles of Association. In addition, under Norwegian law, Panoro's shareholders have a preferential right to subscribe to issues of new shares. The preferential rights to subscribe to an issue may be waived by a resolution in a general meeting passed by the same vote required to approve amendments to the Articles of Association. A waiver of the shareholders' preferential rights in respect of bonus issues requires the approval of all outstanding shares, irrespective of class.

The general meeting may, with a vote as required for amendments to the Articles of Association, authorize the Board of Directors to issue new shares, and to waive the preferential rights of shareholders in connection with such issuances. Such authorization may be effective for a maximum of two years, and the par value of the shares to be issued may not exceed 50% of the registered nominal share capital when the authorization is registered.

Under Norwegian law, bonus shares may be issued, subject to shareholder approval, by transfer from Panoro's distributable equity or from its share premium reserve. Any bonus issues may be effectuated either by issuing shares or by increasing the par value of the shares outstanding.

To issue shares to holders who are citizens or residents of the United States upon the exercise of preferential rights, Panoro may be required to file a registration statement in the United States under United States securities laws. If Panoro decides not to file a registration statement, such holders may not be able to exercise their preferential rights and in such event would be required to sell such rights to eligible Norwegian persons or other eligible non-U.S. holders to realize the value of such rights.

12.4.8 Shareholder Vote on Certain Reorganizations

A decision to merge with another company or to demerge requires a resolution of the shareholders passed by two-thirds of the aggregate votes cast at a 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 shareholders at least one month prior to the shareholders' meeting.

12.4.9 Legal constraints on the distribution of dividends

Under Norwegian law, no interim dividends may be paid in respect of a financial period as to which audited financial statements have not been approved by the Annual General Meeting of shareholders. Any proposal to pay a dividend must be recommended or accepted by the Board of

Directors and approved by the shareholders at a General Meeting. The shareholders may vote to reduce (but not to increase) the dividends proposed by the board of directors.

Dividends in cash or in kind are payable only out of (i) the annual profit according to the adopted income statement for the last financial year, (ii) retained profit from previous years, and (iii) distributable reserves, after deduction of (a) any uncovered losses, (b) the book value of research and development, (c) goodwill, (d) net deferred tax assets recorded in the balance sheet for the last financial year, the aggregate value of any treasury shares that the company has purchased or been granted security over during the preceding financial years, (f) any credit or security given pursuant to sections 8-7 to 8-9 of the Norwegian Public Limited Companies Act and provided always that such distribution is compatible with good and prudent business practice with due regard to any losses which may have occurred after the last balance sheet date or which may be expected to occur. The company cannot distribute any dividends if the equity, according to the balance sheet, amounts to less than 10% of the total balance sheet without following the procedure for capital decrease with two months' creditor notice period.

The Board of Directors will consider the amount of dividend (if any) to recommend for approval by the Company's shareholders, on an annual basis, based upon the earnings of the company for the years just ended and the financial situation of the company at the relevant point in time. Hence, the shareholders do not have an absolute entitlement to share in the Company's profits.

Under Norwegian foreign exchange controls currently in effect, transfers of capital to and from Norway are not subject to prior governmental approval. However, all payments to and from Norway shall be registered with the Norwegian Currency Registry. Such registration is made by the entity performing the transaction. Further, each physical transfer of payments in currency shall be notified to the Norwegian customs. Consequently, a non-Norwegian resident may receive dividend payments without Norwegian exchange control consent if such payment is made through a licensed bank.

The Norwegian Public Limited Liability Companies Act does not provide for any time limit after which entitlement to dividends lapses.

All shareholders that are shareholders at the time the General Meeting makes its resolution are entitled to dividend.

12.4.10 Procedure for dividend payments

Any potential future payments of dividends on the Shares will be denominated in NOK, and will be paid to the shareholders through the VPS. Payment to investors registered in the VPS whose address is outside Norway will be conducted by the Company's registrar (DNB) based on information received from the VPS. Investors with an address outside Norway who have registered a valid bank account with the VPS will receive the dividend payment to the registered bank account while investors who have not registered a bank account with the VPS will receive the dividend payment as a check mailed to the address that the investor has registered in the VPS.

12.4.11 Related Party Transactions

Under Norwegian law, an agreement between Panoro and a shareholder, the shareholder's parent, a director of Panoro or the CEO of Panoro, or any connected person to the shareholder or the shareholder's parent, which involves consideration from the company in excess of 1/20th of the Company's share capital at the time of such agreement is not binding on the Company unless the agreement has been approved by a General Meeting. Certain exemptions may apply, e.g. business agreements in the normal course of the Company's business containing pricing and other terms and conditions which are normal for such agreements, as well as the purchase of securities at a price which is in accordance with the official quotation. Any performance of an agreement which is not binding on the Company must be reversed.

12.4.12 Minority Rights

Norwegian law contains a number of protections for minority shareholders against oppression by the majority, including but not limited to those described in this and preceding paragraphs. Any shareholder may petition the courts to have a decision of its general meeting declared invalid inter alia on the grounds that it unreasonably favours certain shareholders or third parties to the detriment of other shareholders or the company itself. In certain circumstances shareholders may require the courts to dissolve the company as a result of such decisions. Minority shareholders holding 5% or more of Panoro's share capital have a right to demand in writing that it hold an extraordinary general meeting to discuss or resolve specific matters. In addition, any shareholder may in writing demand that Panoro place an item on the agenda for any shareholders' meeting if it is notified to the Board of Directors at least 7 days before the deadline to call for the shareholders' meeting together with a proposal for resolution or an explanation as to why the item is to be placed on the agenda. If the notice has been issued when such a written demand is presented, a renewed notice must be issued if at least 21 days remain before the shareholders' meeting is to be held.

12.4.13 Liability of Directors

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 Panoro when exercising their functions and exercise a general duty of loyalty and care towards Panoro. 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 Panoro. Norwegian law permits the general meeting to exempt any such person from liability, but the exemption is not binding if substantially correct and complete information was not provided at the general meeting when the decision was taken. If a resolution to grant such exemption 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 Panoro's 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 Panoro's behalf and in its name. The cost of any such action is not Panoro's responsibility, but can be recovered from any proceeds it receives as a result of the action. If the decision to grant an exemption from liability or not to pursue claims is made by such a majority as is necessary to amend the Articles of Association, the minority shareholders cannot pursue the claim in Panoro's name.

12.4.14 Indemnification of Directors and Officers

Neither Norwegian law nor the Articles of Association contain any provision concerning indemnification by Panoro of the Board of Directors. However, as of the date of this Prospectus, Panoro has a Directors and Officers liability insurance program for its Board of Directors.

12.4.15 Insolvency/Liquidation

According to the Norwegian Public Limited Liability Companies Act, the Company may be liquidated by a resolution in a general meeting of the Company passed by a two-thirds majority of the aggregate votes cast as well as two thirds of the aggregate share capital represented at such meeting. The Shares rank pari-passu in the event of a return on capital by the Company upon a liquidation or otherwise.

In the event a resolution to liquidate the Company has been made, the Company's assets shall be transformed to cash in order to cover the Company's contractual obligations and for distribution to the shareholders as long as the shareholders have not accepted to receive the dividends in kind.

12.5 SECURITIES TRADING IN NORWAY

As a company listed on Oslo Børs, Panoro is subject to certain duties to inform the market under the Stock Exchange Regulations, and the insider trading regulation of Chapter 3 of the Securities Trading Act. Furthermore, the Company is subject to Norwegian securities regulations and supervision by the relevant Norwegian authorities.

12.5.1 Trading and settlement

Trading of equities on Oslo Børs/Oslo Axess is carried out in the electronic trading system Millennium Exchange. This trading system is in use by all markets operated by the London Stock Exchange as well as by the Borsa Italiana and the Johannesburg Stock Exchange. Official trading on Oslo Børs/Oslo Axess takes place between 09:00 CET and 16:20 CET each trading day, with a pre-trade period between 08:15 CET and 09:00 CET, a closing auction between 16:20 CET and 16:25 CET and a post-trade period from 16:25 CET to 17:30 CET. Reporting of after exchange trades can be done until 17:30 hours (CET).The settlement period for trading on Oslo Børs/Oslo Axess 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.

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 a member state of the European Economic Area (the "**EEA**"), 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 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. Such market-making activities do not as such require notification to the Norwegian Financial Supervisory Authority or Oslo Børs, except for the general obligation of investment firms that are members of Oslo Børs to report all trades in stock exchange listed securities

12.5.2 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.

Under Norwegian law, implementing the EU Market Abuse Directive, a company that is listed on a Norwegian regulated market, or that is subject to the application for listing on such market, must promptly release any inside information (i.e., precise information about financial instruments, the issuer thereof, or other matters that are likely to have a significant effect on the price of the relevant financial instruments or related financial instruments, and that 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.

12.5.3 The VPS and transfer of shares

The Company's Shareholder register is operated through the VPS. The VPS is the Norwegian paperless centralized securities register. It is a computerized bookkeeping system in which the ownership of, and all transactions relating to, Norwegian listed shares must be recorded. The VPS and Oslo Børs are both wholly owned by Oslo Børs VPS Holding ASA.

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 (that is, Norway's central bank), authorized securities brokers in Norway and Norwegian branches of credit institutions established within the EEA are allowed to act as account agents.

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, by the relevant company's general meeting, 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's control, of which the VPS could not reasonably be expected to avoid or overcome the consequences. 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 on-going basis, as well as any information that the Norwegian Financial Supervisory Authority 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.

12.5.4 Share register

Under Norwegian law shares are registered in the name of the owner of the shares. As a general rule, there are no arrangements for nominee registration. However, shares may be registered with VPS in the name of a depositary (bank or other nominee) approved by the Norwegian Financial Supervisory Authority, to act as nominee for Non-Norwegian shareholders. 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 the case of registration by nominees, registration with 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 at general meetings on behalf of the beneficial owners. Beneficial owners must register with VPS or provide other sufficient proof of their ownership to the shares in order to vote at general meetings.

12.5.5 Foreign investment in Norwegian shares

Non-Norwegian investors may trade shares listed on Oslo Børs through any broker that is a member of Oslo Børs, whether Norwegian or Non-Norwegian.

12.5.6 Insider trading

According to Norwegian law subscription for, purchase, sale or exchange of shares which are listed or in respect of which a listing application has been submitted or incitement to such dispositions, must not be undertaken by anyone who has inside information, as defined in section 3-2 of the Norwegian Securities Trading Act.

The same applies to entry into, purchase, sale or exchange of option or futures/forward contracts or equivalent rights connected with such shares or incitement to such disposition.

12.5.7 Mandatory offer requirement

Pursuant to the Securities Trading Act, any person, entity, or group acting in concert that acquires shares representing more than 1/3 (with a repeated obligation at 40% and at 50%) of the voting rights of a Norwegian company whose shares are listed on Oslo Børs or Oslo Axess is obliged to make an unconditional general offer for the purchase of the remaining shares in the company within four weeks or, within the same period, dispose of a number of voting shares which brings the percentage of voting rights down to or below 1/3.

The shareholder must, immediately upon reaching any of the said thresholds, notify the Company and Oslo Børs accordingly and of whether it will make a mandatory offer or perform a sell-down. A notice informing about a disposal can be altered to a notice of making an offer within the four week period, while a notice stating that the shareholder will make an offer cannot be amended and is thus binding. The mandatory offer obligation ceases to apply if the person, entity, or consolidated group notifies the Company and Oslo Børs of its decision to sell down and then 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.

An offer is subject to approval by Oslo Børs before submission of the offer to the shareholders or made public. The offer price per share must be at least as high as the highest price paid or agreed to be paid by the offeror in the six-month period prior to the date the 1/3 threshold was exceeded, but at least equal to the market price, if it is clear that the market price was higher when the mandatory offer obligation was triggered. Note, however, that the EFTA court in a statement dated 10 December 2010 has concluded that the "market price" alternative is not in compliance with EU regulations. Consequently, there is currently doubt as to the legal validity of this alternative. 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 unconditional and in cash (NOK), but it may contain a consideration alternative at least equivalent to the cash consideration offered. Until an offer has been made or a disposal completed, the shareholder will have no voting rights or other rights relating to the shares exceeding the offer threshold, apart from the right to receive dividends and pre-emption rights in the event of a share capital increase. In case of the failure to make a mandatory offer or to sell the portion of the shares that exceeds the relevant threshold within four weeks, the Oslo Børs may force the acquirer to sell the shares exceeding the threshold by public auction.

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 that 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.

The Company has not received any takeover bids or bids to acquire controlling interest during 2017 or the current financial year.

12.5.8 Compulsory Acquisition

Pursuant to the Norwegian Public Limited Liability Companies Act and the 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 liability 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.

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.

Absent a request for a Norwegian court to set the price, or any other objection to the price being offered in a compulsory acquisition, the minority shareholders would be deemed to have accepted the offered price after the expiry of the specified deadline for raising objections to the price offered in the compulsory acquisition.

In event a shareholder, directly or through subsidiaries, exceeds the 90% threshold by way of a mandatory offer in accordance with the Securities Trading Act, and a compulsory acquisition is resolved within three months, then the share price in the compulsory acquisition shall be equal to the price in the mandatory offer if no special circumstances call for a different price. Further, if the 90% threshold is exceeded by way of a voluntary offer, the compulsory acquisition may, 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 according to the rules for mandatory offers.

12.5.9 Disclosure Obligations

A person, entity or group acting in concert that acquires shares, options for shares or other rights to shares (i.e. convertible loans or subscription rights) resulting in its beneficial ownership, directly or indirectly, in the aggregate meeting or exceeding the respective thresholds of 5%, 10%, 15%, 20%, 25%, 1/3, 50%, 2/3 or 90% of the share capital or the voting rights in the Company has an obligation under Norwegian law to notify Oslo Børs immediately. The same applies to disposal of shares, option for shares etc., resulting in a beneficial ownership, directly or indirectly, in the aggregate meeting or falling below said thresholds.

The reporting obligations will also apply if the thresholds are reached or passed as a result of events changing the relative ownership or voting stake by "passive" means e.g. if a company is increasing its share capital and thereby causes an existing shareholder not participating in the capital increase to be diluted.

12.6 SHAREHOLDER AND DIVIDEND POLICY

12.6.1 Shareholder policy

Any acquisition of own shares will be at market price, and the Company will not deviate from the principle of unreasonable unequal treatment of all shareholders.

12.6.2 Dividend policy

The Company's objectives are to create lasting values and provide competitive returns to its shareholders through profitability and growth.

Long-term returns to shareholders should reflect the value created in the Company in the form of increased share price as well as dividends.

Dividends should arise in line with the growth in the Company's results while at the same time recognizing the need for financial preparedness for cyclical market movements, as well as opportunities for adding value through new profitable investments.

Over time, value added will be reflected to a greater extent by an increased share price, rather than through dividend distributions.

The Company has not paid any dividend since its incorporation in 2009 and 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 Company's financial condition, capital requirements, earnings and other factors deemed relevant by its Board and general meeting of shareholders.

12.7 SHAREHOLDER AGREEMENTS

The Company is not aware of any shareholder agreements among its investors.

12.8 CORPORATE GOVERNANCE

The principle behind good corporate governance is to establish and maintain a strong, sustainable and competitive company in the best interest of the shareholders, employees, business associates, third parties and society at large.

The Board acknowledges the Norwegian recommendation of the Corporate Governance Code, and the principle of comply or explain. The Board has implemented the Corporate Governance Code and will use its guidelines as the basis for the Board's governance duties. As of the date of this Prospectus, the Company is in compliance with the Corporate Governance Code with the following qualifications:

Currently, the Audit Committee consists of the complete Board. The reason for this is the rather low number of directors in the Company, which has led the Board to conclude that it is currently more efficient for the Board work that all directors also are members of the Audit Committee. This practice will be further assessed in the future.

13. NORWEGIAN TAXATION

13.1 INTRODUCTION

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 Norwegian laws, rules, and regulations in force in Norway as at 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 summary does not address foreign tax laws.

The following summary is of a general nature and does not purport to be a comprehensive description of all the Norwegian tax considerations that may be relevant for a decision to acquire, own or dispose of Shares. 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.

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.

13.2 NORWEGIAN SHAREHOLDERS

13.2.1 Taxation of dividends

13.2.1.1 Norwegian Individual Shareholders

Dividends received by shareholders who are individuals resident in Norway for tax purposes ("**Norwegian Individual Shareholders**") are taxable as ordinary income for such shareholders. The tax rate is 23 %. However, in the income year 2018 dividend income exceeding the basic tax free allowance is grossed up with a factor of 1.33 before taken to taxation, resulting in an effective tax rate of 30.59 (23 percent x 1.33).

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 after tax of interest on treasury bills (Norwegian: "statskasseveksler") with three months' maturity. The allowance is calculated for each calendar year, and it is allocated solely to Norwegian Individual Shareholders holding shares at the expiration of the relevant income year.

Norwegian Individual 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. Any excess allowance will also be included in the basis for calculating the allowance on the same share in the following years.

13.2.1.2 Norwegian Corporate Shareholders

Dividends received by shareholders that are limited liability companies (and certain similar entities) resident in Norway for tax purposes ("**Norwegian Corporate Shareholders**") are effectively taxed at a rate of 0.69% (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 23%).

13.2.2 Taxation of capital gains on realization of shares

13.2.2.1 Norwegian Individual Shareholders

Sale, non-proportionate redemption, or other disposals of shares is considered as realization for Norwegian tax purposes. A capital gain or loss generated by a Norwegian Individual Shareholder through realization of shares is taxable or tax deductible in Norway. Such capital gain or loss is included in or deducted from the shareholder's ordinary income in the year of disposal. Ordinary income is taxable at a rate of currently 23%. However, in the income year 2018 gain exceeding the basic tax free allowance is grossed up with a factor of 1.33 before taken to taxation, resulting in an effective tax rate of 30.59 (23 percent x 1.33).

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 Individual Shareholder's cost price of the share, including any costs incurred in relation to the acquisition or realization of the share. From this capital gain, Norwegian Individual 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 13.2.3.1 "Norwegian Individual Shareholders" under Section 13.3.1 "Taxation of dividends" of this Prospectus 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.

If the Norwegian Individual 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.

13.2.2.2 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 purpose.

13.2.3 Taxation of Subscription Rights

13.2.3.1 Norwegian Individual Shareholders

A Norwegian Individual Shareholder's subscription for shares pursuant to a subscription right is not subject to taxation in Norway. Costs related to the subscription for the shares will be added to the cost price of the shares.

Sale and other transfer of subscription rights are considered a realization for Norwegian tax purposes. A capital gain or loss generated by a Norwegian Individual Shareholders through a realization of subscription rights is taxable or tax deductible in Norway. Such capital gain or loss is included in or deducted from the basis for the computation of ordinary income in the year of disposal. The ordinary income is taxable at a flat rate currently of 23%%, however, the gain exceeding the basic tax free allowance is grossed up with a factor of 1.33 before taken to taxation, resulting in an effective tax rate of 30.59 (23 percent x 1.33).

13.2.3.2 Norwegian Corporate Shareholders

A Norwegian Corporate Shareholder's subscription for shares pursuant to a subscription right is not subject to taxation in Norway. Costs related to the subscription for the shares will be added to the cost price of the shares.

Sale and other transfer of subscription rights are considered a realization for Norwegian tax purposes. Norwegian Corporate Shareholders are exempt from tax on capital gains derived from the realization of subscription rights qualifying for the Norwegian participation exemption. Losses upon the realization and costs incurred in connection with the purchase and realization of such subscription rights are not deductible for tax purposes

13.2.4 Net wealth tax

The value of shares and subscription rights is included in the basis for the computation of net wealth tax imposed on Norwegian Individual Shareholders. Currently, the marginal wealth tax rate is 0.85% of the value assessed. The value for assessment purposes for listed shares is equal to 80

% of the listed value, while subscription rights is valued to the listed value as of 1 January in the year of assessment (i.e. the year following the relevant fiscal year).

Norwegian Corporate Shareholders are not subject to net wealth tax.

13.3 FOREIGN SHAREHOLDERS – NORWEGIAN TAXATION

13.3.1 Taxation of dividends

13.3.1.1 Non-Norwegian Individual Shareholders

Dividends distributed to shareholders who are individuals not resident in Norway for tax purposes ("**Non-Norwegian Individual 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 Individual Shareholders resident 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 in respect of each individual share (please see "Taxation of dividends – Norwegian Individual 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 a lower taxation on the dividends than the withholding tax rate of 25% less the tax-free allowance.

If a Non-Norwegian Individual 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 Individual Shareholder, as described above.

Non-Norwegian Individual Shareholders who have suffered a higher withholding tax than set out in an applicable tax treaty may apply individually to the Norwegian tax authorities for a refund of the excess withholding tax deducted.

13.3.1.2 Non-Norwegian Corporate Shareholders

Dividends distributed to shareholders that are limited liability companies not resident in 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 resident within the EEA for tax purposes are exempt from Norwegian 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 the Non-Norwegian Corporate Shareholder holds the shares in connection with business activities in Norway, the shareholder will be subject to the same taxation as a Norwegian Corporate Shareholders, as described above.

Non-Norwegian Corporate Shareholders who have suffered to 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 withheld. The same applies to Non-Norwegian Corporate Shareholders within the EEA that are exempt from Norwegian tax on dividends, pursuant to participation exemption.

Nominee registered shares will be subject to withholding tax at a rate of 25% unless the nominee has obtained approval from the Norwegian Directorate of Taxes 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.

13.3.1.3 Non-Norwegian Shareholders tax-resident within the EEA

Foreign Shareholders who are individuals tax-resident within the EEA ("**Foreign EEA Personal Shareholders**") are upon request entitled to a deductible allowance. The shareholder shall pay the lesser amount of (i) withholding tax according to the rate in an applicable tax treaty or (ii) withholding tax at 25% of taxable dividends after allowance. Foreign EEA Personal Shareholders may carry forward any unused allowance, if the allowance exceeds the dividends. With effect for dividends distributed on or after 1 January 2019, specific documentation requirements must be satisfied by the shareholder in order to benefit from reduced withholding.

Foreign Shareholders that are corporations tax-resident within the EEA for tax purposes ("**Foreign EEA Corporate Shareholders**") are exempt from Norwegian tax on dividends distributed from Norwegian limited liability companies, provided that the Foreign EEA Corporate Shareholder in fact is the beneficial owner of the shares and genuinely established within the EEA and performs genuine economic business activities within the EEA

13.3.2 Taxation of capital gains on realization of shares

13.3.2.1 Non-Norwegian Individual Shareholders

Gains from the sale or other disposals of shares in the Company by a Non-Norwegian Individual Shareholder will not be subject to taxation in Norway unless the Non-Norwegian Individual Shareholder holds the shares in connection with business activities carried out in or managed from Norway.

13.3.2.2 Non-Norwegian Corporate Shareholders

Capital gains derived from the sale or other type of realization of shares in the Company by Non-Norwegian Corporate Shareholders are not subject to taxation in Norway

13.3.3 Taxation of Subscription Rights

A Non-Norwegian Shareholder's subscription for shares pursuant to a subscription right is not subject to taxation in Norway.

Capital gains derived by the sale or other transfer of subscription rights by Non-Norwegian Shareholders are not subject to taxation in Norway unless the Non-Norwegian Shareholder holds the subscription rights in connection with business activities carried out or managed from Norway. Such taxation may be limited according to an applicable tax treaty or other specific regulations

13.3.4 Net wealth tax

Shareholders not resident in Norway for tax purposes are not subject to Norwegian net wealth tax.

Non-Norwegian Individual Shareholders may, however, be taxable if the shareholding is effectively connected to the conduct of trade or business in Norway.

13.4 VAT AND TRANSFER TAXES

No VAT, stamp or similar duties are currently imposed in Norway on the transfer or issuance of shares.

13.5 INHERITANCE TAX

A transfer of shares through inheritance or as a gift does not give rise to inheritance or gift tax in Norway.

14. LEGAL MATTERS

14.1 LEGAL AND ARBITRATION PROCEEDINGS

The Group will from time to time be involved in disputes in the ordinary course of its business activities. The Group is currently not involved in any legal disputes.

As of the date of this Prospectus, the Company is not aware of any governmental, legal or arbitration proceedings (including any such proceedings which are pending or threatened), which may have, or have had during the last twelve months, significant effects on the Group's financial position or profitability.

14.2 MATERIAL CONTRACTS OUTSIDE THE ORDINARY COURSE OF BUSINESS

The Group has not entered into any material contracts outside the ordinary course of business.

14.3 RELATED PARTY TRANSACTIONS

In the period comprised by the historical Financial Statements and up until the date of this Prospectus, the Group has not entered into any related party transactions.

15. ADDITIONAL INFORMATION

15.1 DOCUMENTS ON DISPLAY

For the life of this Prospectus the following documents (or copies thereof), where applicable, may be inspected at the offices of the Company (c/o Michelet & Co Advokatfirma AS, Grundingen 3, 0250 Oslo):

- The Memorandum and Articles of Association of the Company
- 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 the Prospectus;
- The audited financial accounts of the Company for the last two financial years
- Historical financial information for the Company's subsidiaries for the last two financial years
- This Prospectus

15.2 DOCUMENTS INCORPORATED BY REFERENCE

The information incorporated by reference to this Prospectus should be read in connection with the cross reference list as set out in the table below. The following documents have been incorporated hereto by reference:

Section in Prospectus	Disclosure requirements of the Prospectus	Reference document and link	Page (P) in reference document
Section 6, 7, 8	Interim financial information	Q3 2018: http://mb.cision.com/Public/399/2670367/af88f0fa7afc6468.pdf	12 - 21
		Q3 2017: http://mb.cision.com/Public/399/2393088/9e750ff45fc3aff0.pdf	12 - 22
Section 6, 7, 8	Audited historical financial information	Annual report 2017: http://mb.cision.com/Public/399/2509647/bf485716172059e8.pdf	28 - 31
		Annual report 2016: http://mb.cision.com/Public/399/2253950/adb8409da45fabc8.pdf	22 - 25
		Annual report 2015: http://mb.cision.com/Public/399/9967754/959abd8bac28f497.pdf	24 - 27
Section 4	Audit report	Annual report 2017: http://mb.cision.com/Public/399/2509647/bf485716172059e8.pdf	82 - 85
		Annual report 2016: http://mb.cision.com/Public/399/2253950/adb8409da45fabc8.pdf	67 - 70
		Annual report 2015: http://mb.cision.com/Public/399/9967754/959abd8bac28f497.pdf	70 - 71
Section 6, 7, 8, 9	Accounting policies	Annual report 2017: http://mb.cision.com/Public/399/2509647/bf485716172059e8.pdf	35 - 45

Section 9	Annual statement of reserves	Annual statement of reserves 2017: http://mb.cision.com/Public/399/2509623/acdbbf219a5e5f69.pdf	6
Section 9	Yearly updates of annual statement of reserves	Yearly updates of the annual statement of reserves can be found at: http://www.panoroenergy.com/investors/annual-statement-of-reserves/	N/A (web page)

16. STATEMENT REGARDING EXPERT OPINIONS

The Company confirms that when information in this Prospectus has been sourced from a third party it has been accurately reproduced and as far as the Company is aware and is able to ascertain from the information published by that third party, no facts have been omitted which would render the reproduced information inaccurate or misleading. The sources are mentioned whenever retrieved from an external party and whether it is a payable service.

The Company has adopted a policy of regional Reserve Reporting using external third party companies to audit its work and certify reserves and resources according to the guidelines established by the Oslo Stock Exchange (OSE). Reserve and Contingent Resource estimates comply with the definitions set by the Petroleum Resources Management System (PRMS-2007) sponsored by Society of Petroleum Engineers/World Petroleum Council/ American Association of Petroleum Geologists/ Society of Petroleum Evaluation Engineers (SPE/WPC/AAPG/SPEE) as issued in March 2007.

The Company's reserves have, on request by the Company, been verified by its certification agents;

Gaffney, Cline & Associates ("GCA")
Bentley Hall
Blacknest
Alton
GU34 4PU
United Kingdom

Gaffney, Cline & Associates has no material interest in the Company. The report is signed by Dr. John Barker who has 33 years of industry experience. Dr. John Barker holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers. The report has been prepared on the request of the Company, for publication purposes. The reserve report is incorporated by reference in Section 15.2.

16.1 THIRD PARTY INFORMATION

Market and industry data used throughout this Prospectus was obtained from various publicly available or independent third party sources. Although the Company believes that these independent sources are generally reliable, the accuracy and completeness of such information are not guaranteed and have not been verified with complete certainty due to limits on the availability and reliability of raw data, the voluntary nature of the data gathering process and the limitations and uncertainties inherent in any statistical survey of market size or consumer demand. References in this Prospectus to research reports or articles should not be construed as depicting the complete findings of the entire referenced report or article. The information in each report or article is not incorporated by reference into this Prospectus.

The information in this Prospectus that has been sourced from third parties has been accurately reproduced and, as far as the Company is aware and able to ascertain from the information published by that third party, no facts have been omitted that would render the reproduced information inaccurate or misleading.

17. DEFINITIONS AND GLOSSARY

AGM	Annual General Meeting
AIPN	Association of International Petroleum Negotiators
ANP	The Brazilian directorate Agência Nacional do Petróleo, Gás Natural e Biocombustíveis
Anti-Money Laundering Legislation	Norwegian Money Laundering Act of 6 March 2009 no. 11 and the Norwegian Money Laundering Regulation
Australian Corporations Act	Corporations ACT 2001 (Cth) of Australia
Board of Directors or Board	The Board of Directors of Panoro Energy ASA
BRL	Brazilian Real
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CET	Central European Time
CITA	Companies Income Tax Act, Cap 21 2004 of the Federal Republic of Nigeria, as amended from time to time
CO	Companies Ordinance of Hong Kong (cap. 32)
Company, Panoro or Panoro Energy	Panoro Energy ASA and its consolidated subsidiaries
DIBPSA	The Deep Offshore & Inland Basin Production Sharing Contract Act 2004 of the Federal Republic of Nigeria, as amended from time to time
DGH	Direction Générale des Hydrocarbures, the government entity responsible for the upstream sector in Gabon
DMO	Domestic Market Obligation
DPR	The Department of Petroleum Resources of the Nigerian Federal Ministry of Petroleum Resources
DST	Drill stem test
EBITDA	Represents operating income before depreciation and write-downs
EEA	European Economic Area
EGM	Extraordinary General Meeting in the Company held on 29 November 2018
EIA	Energy Information Agency
Ernst & Young	Ernst & Young AS, the Company's auditor
EUR	Euro, the currency introduced at the start of the third stage of the Economic and Monetary Union to the Treaty establishing the European Economic Community, as amended by the Treaty on the European Union.
E&P	Exploration and production
FEED	Front-End Engineering Design
FDP	Field development plan
FID	Final Investment Decision
FPSO	Floating Production Storage and Offloading vessel, a marine vessel used to extract oil
Foreign EEA Corporate Shareholders	Foreign Shareholders that are corporations tax resident within the

	EEA for tax purposes
Foreign EEA Personal Shareholders	Foreign Shareholders who are individuals tax-resident within the EEA
GCA	Gaffney, Cline & Associates, the Company's certification agent
GOR	Gas/Oil Ratio
G&A	General and administration costs
G&G	Geological and Geophysical
IEA	International Energy Agency
IFRS	International Financing Reporting Standards, issued by the International Financial Reporting Interpretations Committee (IFRIC) (formerly, the "Standing Interpretations Committee" (SIC)).
ISIN	International Securities Identification Number.
JOA	Joint Operating Agreement
JV	Joint venture
boepd	Barrels of Oil Equivalents per day
Managers	Pareto Securities AS and Sparebank1 Markets AS
MEND	The Movement for the Emancipation of the Niger Delta
MKB	Mengo-Kunji-Bindi (license in Republic of Congo)
NOK	Norwegian Kroner, the lawful currency of the Kingdom of Norway
Non-Norwegian Corporate Shareholders	Shareholders that are limited liability companies resident not resident in Norway for tax purposes
Non-Norwegian Individual Shareholders	Shareholders who are individuals not resident in Norway for tax purposes
Norse Energy	Norse Energy Corp. ASA, the legal name of the merged entity of Northern Oil ASA and Naturgass (USA) AS
Norwegian Corporate Shareholders	Shareholders who are limited liability companies (and certain similar entities) resident in Norway for tax purposes
Norwegian Individual Shareholders	Shareholders who are individuals resident in Norway for tax purposes
Norwegian Public Limited Liability Companies Act	The Norwegian Public Limited Liability Companies Act of 13 June 1997 no. 45 ("Allmennaksjeloven").
Norwegian Securities Trading Act	The Securities Trading Act of 29 June 2007 no. 75 ("Verdipapirhandelloven")
OML	Oil Mining Lease
OPEC	Organization of Petroleum Exporting Countries
OPL	Oil Prospecting License
OSE	Abbreviation for Oslo Børs or Oslo Stock Exchange
Oslo Børs or Oslo Stock Exchange	Oslo Børs ASA (translated "the Oslo Stock Exchange")
PDPR	Petroleum (Drilling & Production) Regulations
PIB	The Nigerian Petroleum Industry Bill
PPAL	Pan-Petroleum Aje Limited
PPHCL	Pan Petroleum Cyprus Holdings Limited
PPT	Petroleum Profit Tax
PPTA	Petroleum Profits Tax Act 2004 of the Federal Republic of Nigeria, as amended from time to time

PSC	Production Sharing Contract
Relevant Member State	Each member state of the EEA other than Norway
RSU	Restricted Share Units award scheme of Panoro
The Ruche Area EEA	Exclusive Exploitation Authorisation granted by the Gabonese government for exploiting the resources inherent in the Dussafu Marin Permit
SFO	Securities and Futures Ordinance of Hong Kong (Cap. 571)
Share(s)	"Shares" means the common shares in the capital of the Company each having a nominal value of NOK 0.05 "Share" means any one of them.
SNPC	Societe Nationale des Petroles du Congo
TAP	Total allowable production
Tcf	Trillion cubic feet
TRACS	The competent person's report of July 2014 certifying reserves of the Aje development
US$	United States Dollar, the lawful currency of the United States of America.
U.S. Securities Act	The U.S. Securities Act of 1933, as amended
VPS account	An account with VPS for the registration of holdings of securities.
VPS	Verdipapirsentralen (Norwegian Central Securities Depository), which organizes a paperless securities registration system.
WAGP	West Africa Gas Pipeline
YFP	Yinka Folawiyo Petroleum Company LTD

18. APPENDICES

APPENDIX 1 – Articles of association of Panoro Energy ASA

Articles of Association
For
Panoro Energy ASA

§ 1 The name of the company

The name of the company shall be Panoro Energy ASA. The company is a public limited liability company.

§ 2 The business of the company

The company's business shall consist of exploration, production, transportation and marketing of oil and natural gas and exploration and/or development of other energy forms, sale of energy as well as other related activities. The business might also involve participation in other similar activities through contribution of equity, loans and/or guarantees.

§ 3 Registered office

The company's registered office is in the municipality of Oslo.

§ 4 Share capital and shares

The share capital of the company is NOK 3,119,380 divided into 62,387,600 shares each with a nominal value of NOK 0.05, fully paid and payable to registered owner.

The company's shares shall be registered in the Norwegian Registry of Securities, Verdipapirsentralen (VPS).

§ 5 Board of directors

The board of directors consists of 3 to 8 members.

§ 6 Signature

The power to sign for the company is exercised by the chairman of the board alone or by two board members jointly.

§ 7 Annual general meeting

The following matters will be considered and decided by the annual general meeting:
1. Approval of the profit and loss statement and balance sheet, including application of the profit for the year or coverage of the loss for the year.
2. Election of board of directors and auditor, and determination of their remuneration.
3. Other issues which pursuant to law or the articles of association are to be decided by the annual general meeting.

If documents that shall be considered at the general meeting are made available to the shareholders on the company's website, the Companies Act request to send these documents to shareholders does not apply. This shall also apply for documents that, pursuant to law or regulations, shall be included in or attached to the notice of the general meeting. A shareholder may nevertheless upon request to the company have the documents that shall be considered at the general meeting sent free of charge by mail.

Registrations for the company's general meetings must be received at least five calendar days before the meeting is held.

§ 8 Nomination committee

The company shall have a nomination committee consisting of 2 to 3 members to be elected by the annual general meeting for a two year period. The majority of the nomination committee shall be independent of the board of directors and the day-to-day management. The nomination committee's duties are to propose to the general meeting shareholder elected candidates for election to the board of directors, and to propose remuneration to the board. The annual general meeting may adopt procedures for the nomination committee.

§ 9 Other regulations

In all other matters of the company, the Public Limited Liabilities Companies Act will apply.

APPENDIX 2 – ERNST & YOUNG AUDIT REPORT

Building a better
working world

Statsautoriserte revisorer
Ernst & Young AS

Vassbotnen 11a Forus, NO-4313 Sandnes
Postboks 8015, NO-4068 Stavanger

Foretaksregisteret: NO 976 389 387 MVA
Tlf: +47 24 00 24 00

www.ey.no
Medlemmer av Den norske revisorforening

To the Board of Directors of Panoro Energy ASA

Independent Practitioners' Assurance Report on the compilation of pro forma financial information included in a prospectus

We have completed our assurance engagement to report on the compilation of pro forma financial information of Panoro Energy ASA (the "Company") by the Board of Directors and management of the Company. The pro forma condensed financial information consists of the unaudited condensed pro forma balance sheet as at 31 December 2017 and related notes as set out in section 7.8 of the prospectus dated 14 December 2018 issued by the Company (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 Regulation (EC) no. 809/2004 as incorporated in the Securities Trading Act section 7-13 and described in section 7.8 of the Prospectus (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 7.8 of the Prospectus on the Company's consolidated financial position as at 31 December 2017 as if the transaction had taken place at 31 December 2017. As part of this process, information about the Company's consolidated financial position has been extracted by the Board of Directors and management of the Company from the Company's consolidated financial statements for the year ended 31 December 2017. Information about the acquired entity's financial position has been extracted by the Board of Directors and Management of the Company from the underlying accounting records reported as part of the audited consolidated financial statements of OMV Aktiengesellschaft. The auditor's report on the Company's financial statements for the year ended 31 December 2017 has been incorporated by reference in section 15.2 of the Prospectus.

The Board of Directors and management of the Company's Responsibility for the Pro Forma Financial Information

The Board of Directors and management of the Company is 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 requirement 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 Annex II item 7 of EU Regulation No 809/2004 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 plan and perform procedures to obtain reasonable assurance about whether the Board of Directors and management of the Company has compiled the pro forma financial information on the basis of the applicable criteria and whether this basis is consistent with the accounting policies of the Company. Our work primarily consisted of comparing the unadjusted financial information with the source documents as described in section 7.8 of the Prospectus, 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 OMV Tunisia Upstream GmbH to the accounting policies of the Company, or the assumptions summarized in section 7.8 of the Prospectus. 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 historical financial information of OMV Tunisia Upstream GmbH as at 31 December 2017 used in the compilation of the Pro Forma Financial Information is unaudited and accordingly we do not accept any responsibility for that 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 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 at 31 December 2017 would have been as presented.

A reasonable assurance engagement to report on whether the pro forma financial information has been compiled on the basis stated 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 pro forma adjustments give appropriate effect to those criteria;
- The pro forma financial information reflects the proper application of those adjustments to the unadjusted financial information; and
- The 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 7.8 of the Prospectus; and
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 Oslo Stock Exchange, and other regulated markets in the European Union or European Economic Area as set out in the Prospectus approved by the Financial Supervisory Authority of Norway. Our work has not been carried out in accordance with auditing, assurance or other standards and practices generally accepted in the United States and accordingly should not be relied upon as if it had been carried out in accordance with those standards and practices. Therefore, this report is not appropriate in other jurisdictions and should not be used or relied upon for any purpose other than the listing and issuance of shares described above. We accept no duty or responsibility to and deny any liability to any party in respect of any use of, or reliance upon, this report in connection with any type of transaction, including the sale of securities other than the listing of the shares on Oslo Stock Exchange and other regulated markets in the European Union or

European Economic Area, as set out in the Prospectus approved by the Financial Supervisory Authority of Norway.

Stavanger, 14 December 2018
ERNST & YOUNG AS

Tor Inge Skjellevik
State Authorized Public Accountant (Norway)

APPENDIX 3 – AUDITED FINANCIAL STATEMENTS FOR THE YEAR ENDED 31 DECEMBER 2017

ANNUAL REPORT 2017

Panoro Energy

COMPANY OVERVIEW

CONTENTS

FINANCIAL CALENDAR

May 24, 2018
First quarter 2018 results and Annual General Meeting

August 22, 2018
Second quarter 2018 results

November 13, 2018
Third quarter 2018 results

Panoro Energy ASA is an independent exploration and production (E&P) company based in London and listed on the Oslo Stock Exchange with ticker PEN. The Company holds production, development, and exploration assets in West Africa, namely the Dussafu License offshore southern Gabon and OML 113 offshore western Nigeria. In addition to discovered hydrocarbon resources and reserves, both assets also hold significant exploration potential.

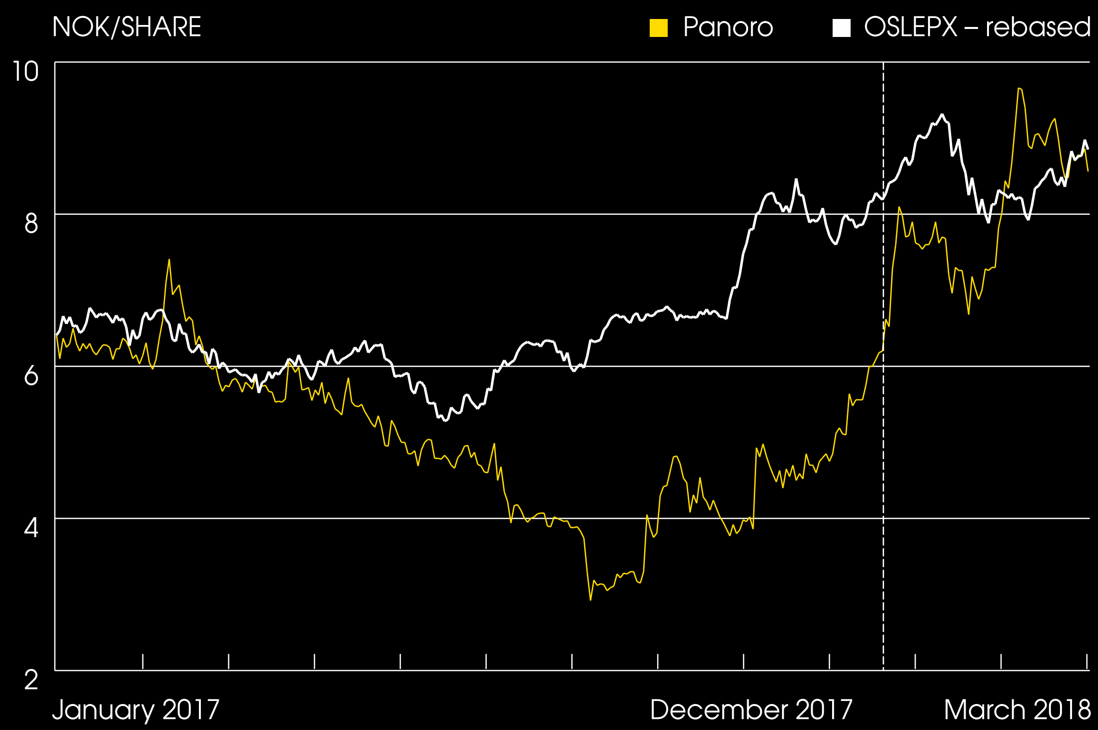
COMPANY OVERVIEW

KEY FIGURES	2017
EBITDA (USD million)	(5.3)
EBIT (USD million)	(36.0)
Net profit/(loss) (USD million)	(36.6)
2P Reserves (MMBOE)	21.6
2C Contingent Resources (MMBOE)	2.6
Share price December 29, 2017 (NOK)	6.20

2017 HIGHLIGHTS AND SUBSEQUENT EVENTS

- Completion of the divestment of a 25% working interest in Dussafu for USD 12.0 million in cash and a non-recourse loan of up to USD 12.5 million.
- Final Investment Decision on Tortue field development.
- USD 1.5 million returned post-period end following the settlement of legal dispute with Aje JV partners.
- Submission of Aje Turonian gas Field Development Plan.
- Aje-5-ST2 well completed in Turonian oil rim and started production.
- Share buyback completed in August 2017, purchasing 1,000,000 own shares at NOK 4.05 per share.
- Updated reserves estimates on Aje and Dussafu – material increase in reserves as a result of Tortue FID and Aje gas FDP.
- Start of development activities at Tortue Field including successful completion of the production well DTM-2H.
- Recurring General and Administration (G&A) costs reduced by approximately 10% year-on-year.

SHARE PRICE DEVELOPMENT



ASSETS

GABON

- 8.333% interest in Dussafu Marin permit, offshore.*

  * Panoro's interest reduced to 8.333% (from 33.333%) as a result of the transaction with BW energy in 2017.

NIGERIA

- 6.502% participating interest (12.1913% revenue interest and 16.255% paying interest) in OML 113 Aje field, offshore Nigeria.

PANORO OFFICES

The Company maintains its registered address in Oslo and operational headquarters in London.

PANORO OFFICES

CEO LETTER

Dear Fellow Shareholders:

2017 proved to be a transformational year for Panoro with two distinct halves. The first half was largely dominated by the signature and subsequent closing of the sale purchase agreement of a 25% working interest in the Dussafu PSC to BW Energy, as well by some operational and legal uncertainties surrounding Aje in Nigeria. The second half evolved positively with material development progress at Dussafu in Gabon and the gradual settlement of disagreements in Nigeria. As we entered 2018, Panoro has continued to capitalise on this positive momentum in our asset base, while benefiting of the macro background and the recent increase in oil prices.

In Gabon, Dussafu gained (and continues to gain) momentum with the entry of BW Energy as new Operator on the Dussafu PSC and the farm out transaction which saw Panoro's subsidiary financed through the development of Phase 1. The development of the Tortue oil field at Dussafu is going according to plan. Various installation activities were carried out in preparation for the drilling and main installation phase at Tortue, with drilling commencing post period in January 2018. The first development well, DTM-2H, was completed in April 2018, and a second development well, DTM-3H is expected to complete drilling by the end of June. In addition, an appraisal penetration, DTM-3, is being drilled in the northwest of the Tortue field to confirm the extent of the field and prepare for additional wells which may be part of the second phase of the development. First oil production is anticipated during the second half of 2018.

An independent reserves report was completed by Netherland Sewell & Associates Inc. ("NSAI") which showed a material increase of over 80% of mid-case 2P reserves at Tortue, compared to the previous independent report completed in May 2014, prior to the new seismic data being available. The NSAI reserves review does not yet include the other 3 discovered fields in the Exclusive Exploitation Authorisation ("EEA") area (Ruche, Moubenga and Walt Whitman) which will be updated in due course. In addition, the independent reserves review does not include prospective resources associated with the 27 prospects and leads already identified within the EEA area. The Dussafu PSC is at the start of its 20 year term, and will hopefully become a long term legacy asset for Panoro and the Republic of Gabon.

In Nigeria, production at the Aje field in OML 113 averaged around 300 barrels of oil per day net to Panoro with the Aje-4 and Aje-5 wells producing from the Cenomanian and the Turonian reservoirs, respectively. A Field Development Plan describing the development of the Turonian reservoir has been submitted to the Nigerian regulators for consideration. In parallel, the process for the renewal of the OML 113 lease in June 2018 has commenced. The Turonian gas and liquids development is currently the focus of forward planning by the Joint Ventures partners, as this is where the material future value in OML 113 lies.

During the year, Panoro has continued its focus on cost reduction. General and Administrative costs decreased 10% year on year, following the 16% and 10% reductions achieved in 2016 and 2015, respectively. The Brazilian operations and overhead are now largely unwound, although remedial abandonment and administrative costs are still being incurred. During the year, Panoro also purchased 1 million of its own shares at an average price of NOK 4.05, through an approved buy- back programme.

Panoro continues to use its best endeavours to pursue transformational and accretive M&A transactions in order to strengthen its core position in Africa. The aim is to establish a balanced growth platform with production, development and low cost exploration upside. New opportunities are continually being reviewed and assessed with the objective of creating value for all shareholders.

I would like to thank shareholders for their continued support and commitment.

John Hamilton
CEO, Panoro Energy ASA

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COMPANY OPERATIONS

Panoro Energy currently has production and development assets in West Africa, namely the Dussafu License offshore southern Gabon and OML 113 offshore western Nigeria. In addition to discovered hydrocarbon resources and reserves, both assets also hold significant exploration potential.

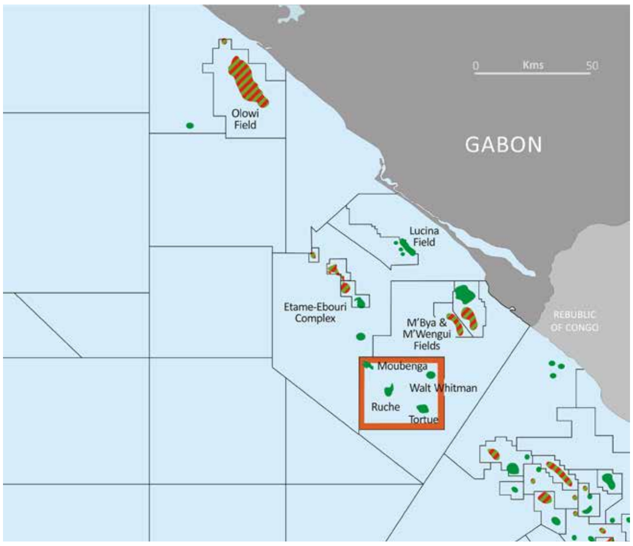
GABON

Dussafu Marin Permit (8.333% interest).

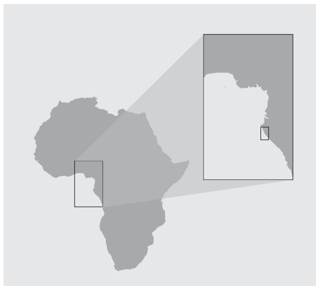
The Dussafu block lies at the southern end of the South Gabon sub-basin in water depths ranging from 100 – 500 metres. The Dussafu block is a Development and Exploitation license with multiple discoveries and undrilled structures lying within a proven oil and gas play fairway within the Southern Gabon Basin. Most of the block lies in less than 200 m of water and has been explored since the 1970s. To the north west of the block is the Etame-Ebouri trend, a collection of fields producing from the pre-salt Gamba and Dentale sandstones, and to the north are the Lucina and M'Bya fields which produce from the syn-rift Lucina sandstones beneath the Gamba.

A total of 20 wells have been drilled in the greater Dussafu block to date, of which five have been pre-salt discoveries (four oil and one gas) and oil shows are present in most other wells. Panoro has participated in the last two exploration wells of which both encountered hydrocarbons; Ruche (2011) and Tortue (2013).

In 2014, an Exclusive Exploitation Authorization (EEA) for an 850.5 km2 area within the Dussafu PSC was awarded. A Field Development Plan (FDP) for the EEA area was subsequently approved and a final decision to start developing the license was taken in 2017. The EEA area includes the four oil fields discovered on the license to date and numerous undrilled structures that could be economically and expeditiously developed through the EEA area development infrastructure. The EEA allows the Dussafu joint venture partners to exploit hydrocarbon resources in the area of the EEA for up to 20 years from first oil production. In 2016 the remaining portion of the greater Dussafu license area outside of the EEA area was relinquished. The first field in the EEA area, Tortue, is expected to start oil production in 2018 from two initial horizontal development wells drilled in the first



Oil
Oil & Gas



half of 2018. The oil from the Tortue wells will be produced via subsea trees and flowlines to a leased FPSO for processing, storage and export. It is expected that further development and exploration drilling will follow this first phase of the development.

In February 2018, Netherland, Sewell and Associates, Inc. (NSAI) certified (3rd party) gross 1P Proved Reserves of 15.9 MMbbls in the Gamba and Dentale reservoirs of the Tortue field. Gross 2P Proved plus Probable Reserves at Tortue amounted to 23.5 MMbbls in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at Tortue amounted to 31.4 MMbbls.In addition to these Reserves NSAI also certified gross 1C Contingent Resources of 3.7 MMbbls and gross 2C Contingent Resources of 11.6 MMbbls in the Tortue field.

At year end Panoro's net entitlement fraction of the Gross Tortue Field Reserves, after deduction of Government share of production and royalties, was 2P Proved plus Probable Reserves of 1.55 MMbbls with additional 2C Contingent Resources of 1.5 MMbbls.

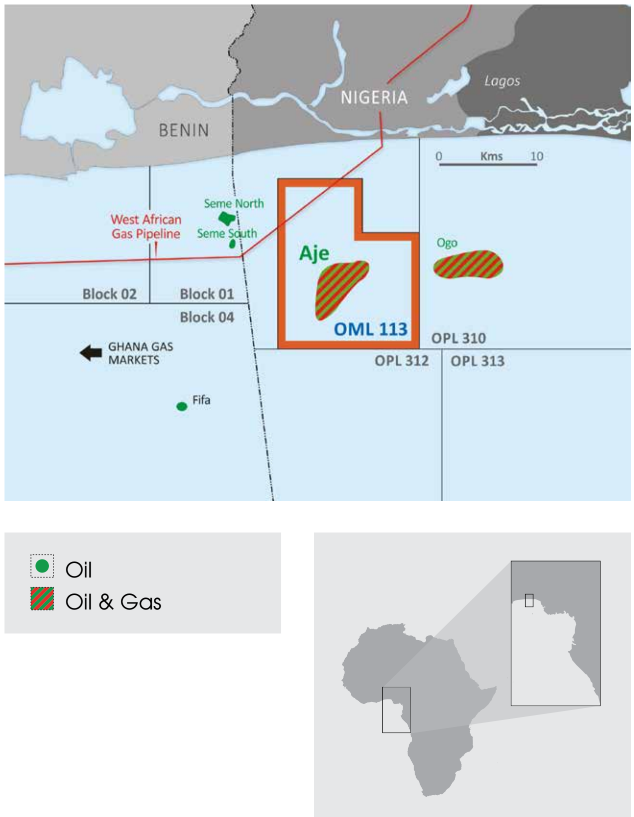
NIGERIA

OML 113 Aje field (6.502% participating interest, 12.1913% revenue interest and 16.255% paying interest).

Covering an area of 840 km2 OML 113 is operated by Yinka Folawiyo Petroleum Limited and is located in the western part of offshore Nigeria, adjacent to the Benin border. The license contains the Aje field as well as a number of exploration prospects. The Aje field was discovered in 1996 in water depths ranging from 100-1,000m. Unlike the majority of Nigerian Fields which are productive from Tertiary age sandstones, Aje has multiple oil, gas and gas condensate reservoirs in the Turonian, Cenomanian and Albian age sandstones. Five wells have been drilled to date on the Aje field. Aje-1 and Aje-2 tested oil and gas condensate at high rates from the Turonian and Cenomanian reservoirs and Aje-4 confirmed the productivity of these reservoirs and discovered an additional deeper Albian age reservoir. Aje-5 was drilled in 2015 as a development well to produce from the Aje oil reservoirs. The OML 113 license has full 3D seismic coverage from surveys acquired in 1997 and 2014.

Production at the Aje field is underway having started in 2016. Aje currently has 2 wells on production, Aje-4 and Aje-5, which were completed as producers in the Cenomanian reservoir in 2015. Aje-5 was side-tracked and re-completed as a producer in the Turonian oil rim in 2017. Oil is processed, stored and exported at the Front Puffin FPSO via a subsea production system. These two wells comprise the first phase of the Aje field development project. During 2017 the Aje field produced a total of 113,000 barrels net to Panoro at an average rate of approximately 300 bopd net.

In July 2017, a Turonian Gas Field Development Plan (FDP) was submitted to Nigerian regulators for consideration. The



FDP comprises four or five production wells in the Turonian tied back to existing and new infrastructure. The process for the renewal of the OML 113 lease in June 2018 has commenced in 2017.

In April 2018, AGR TRACS International prepared an updated CPR incorporating the 2014 seismic data, the results of the Aje side-track drilling, production history since field start-up and the development plan outlined in the Turonian gas FDP. The Aje-5 results have meant that assessment of oil reserves in the Cenomanian have been materially reduced compared to earlier estimates. However, Turonian gas, LPG and condensate have now been re-classified from contingent status to Reserves Justified for Development as a result of the FDP submission.

TRACS has now estimated gross remaining 2P and 2C resources of 136 million barrels of oil equivalent combined could be produced from the Aje field, with gross 3P and 3C resources of 233 million barrels of oil equivalent.

At year-end 2017, 2P Reserves net to Panoro's interest related to OML 113, after deduction of royalties and other adjustments, stood at 20.0 MMBOE and 2C Contingent Resources stood at 1.1 MMBOE. This is an increase in 2P reserves of 16.9 MMBOE and a decrease in 2C resources of 27.6 MMBOE compared to year-end 2016.

BRAZIL

Operations in Brazil

In Brazil, termination agreements for the surrender of Coral and Cavalho Marinho licences have been signed between the JV partners and Brazilian Regulator ANP. The next steps involve various regulatory clearances before dissolution of JV operations. The Company's formal exit from its historical Brazilian business is still ongoing with slow progress towards the approval of abandonment by the Brazilian regulators. Management is working actively with the operator Petrobras to bring matters to a close and to ensure that the ongoing costs are kept to a minimum. However, the timing and eventual costs of such conclusion is uncertain at this stage.

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ANNUAL STATEMENT OF RESERVES 2017

INTRODUCTION

Panoro'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/WPC/ AAPG/ SPEE) as issued in March 2007.

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 actually 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 Panoro'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 Netherland, Sewell and Associates, Inc. (NSAI) in February 2018 for Dussafu and by AGR TRACS International (AGR TRACS) in April 2018 for Aje.

PANORO ASSETS PORTFOLIO

As of year-end 2017, Panoro had two assets with reserves and contingent resources, OML 113 and the Dussafu Permit. A summary description of these assets with status as of year-end 2017 is included below. In addition we refer to the company's web-site for background information on the assets. Unless otherwise specified, all reserves figures quoted in this report are net to Panoro's interest.

Dussafu: offshore Gabon, operator BW Energy, Panoro 8.333%.

Dussafu is a development and exploitation license covering an area containing several oil fields, the most recent discoveries being the Ruche and Tortue fields. In 2014 an Exclusive Exploitation Authorization (EEA) for an 850.5 km2 area within the Dussafu PSC was awarded. A Field Development Plan for the EEA area was subsequently approved and a final decision to start developing the license was taken in 2017. The first field in the EEA area, Tortue, is expected to start oil production in 2018.

In February 2018 NSAI certified (3rd party) gross 1P Proved Reserves of 15.9 MMbbls in the Gamba and Dentale reservoirs of the Tortue field. Gross 2P Proved plus Probable Reserves at Tortue amounted to 23.5 MMbbls in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at Tortue amounted to 31.4 MMbbls.

In addition to these Reserves NSAI also certified gross 1C Contingent Resources of 3.7 MMbbls, gross 2C Contingent Resources of 11.6 MMbbls, and gross 3C Contingent Resources of 28.9 MMbbls in the Tortue field. The remaining Dussafu fields excluding Tortue have gross 2C Contingent Resources of approximately 17.3 MMbbls (taken from Panoro's 2016 ASR).

These evaluations yield 1P Proved Reserves net to Panoro of 1.07 MMbbls, 2P Proved plus Probable Reserves net to Panoro of 1.55 MMbbls and 3P Proved plus Probable plus Possible Reserves net to Panoro of 1.75 MMbbls. Additional potentially recoverable resources net to Panoro are approximately 0.22 MMbbls 1C, 0.7 MMbbls 2C and 1.73 MMbbls 3C. The remaining Dussafu fields excluding Tortue have net 2C Contingent Resources of approximately 0.8 MMbbls (taken from Panoro's 2016 ASR). These Reserves and Contingent Resources are Panoro's net volumes after deductions for royalties and other taxes, reflecting the production and cost sharing agreements that govern the asset.

OML 113 Aje: offshore Nigeria, operator Yinka Folawiyo Petroleum (YFP), Panoro 12.1913%.

The OML 113 license, close to the border with Benin, contains the Aje field which is predominantly a Turonian age gas discovery with significant condensate and an oil rim but also contains a separate Cenomanian age oil leg. The Cenomanian oil has been on production since 2016, and the Turonian oil rim since 2017.

Production during 2017 from the Aje field amounted to 0.9 MMbbls gross and 0.1 MMbbls net to Panoro.

A Field Development Plan (FDP) for Aje Gas was submitted to the Nigerian Government for consideration in 2017. The FDP comprises four or five production wells in the Turonian tied back to existing and new infrastructure.

In April 2018 AGR TRACS certified (3rd party) gross total 1P Proved Reserves of 78.2 MMBOE in the Aje field. Gross 2P Proved and Probable reserves for the field amounted to 127.1 MMBOE. Gross 3P Proved, Probable and Possible reserves for the field amounted to 215.0 MMBOE. Panoro's net entitlement 1P Proved Reserves was 12.1 MMBOE, net entitlement 2P Proved and Probable Reserves was 20.0 MMBOE and net entitlement 3P Proved, Probable and Possible Reserves was 30.9 MMBOE.

AGR TRACS further sub-categorized these reserves as Developed Producing (reserves from existing wells in the field) and Justified for Development.

In addition to these reserves AGR TRACS also certified gross 1C Contingent Resources of 4 MMBOE, 2C Contingent Resources of 9 MMBOE and 3C Contingent Resources of 17.5 MMBOE. Panoro's net entitlement 1C Contingent Resources is 0.49 MMBOE, net entitlement 2C Contingent Resources is 1.10 MMBOE and net entitlement 3C Contingent Resources is 2.13 MMBOE.

MANAGEMENT DISCUSSION AND ANALYSIS

Panoro uses the services of NSAI and AGR TRACS 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 modeling 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 2017 ASR:

Dussafu: In 2017, a Final Investment Decision to develop the Tortue field was taken in the Dussafu project. The Contingent Resources associated with Tortue are therefore now reported as Reserves Approved for Development. In addition a re-determination of the volumes at Tortue was undertaken by NSAI. The remaining fields in Dussafu (Ruche, Walt Whitman and Moubenga) are still classified as Contingent Resources. A decision to develop these fields will trigger a re-assignment of these resources as reserves and a possible re-determination of their volumes.

Aje: The first phase of the Aje Cenomanian oil development started in 2016 with production from two wells. The 2017 the Aje-5 well workover and side-track campaign resulted in a re-completion of the well in the Turonian oil rim. The previous estimates of reserves in Aje were revised by AGR TRACS in 2018. The revisions incorporate the 2014 seismic data, the results of the Aje side-track drilling, historical production data and the development plans outlined in the Aje gas FDP. The result is a reduction in net 2P reserves of 2.6 MMbbls and the addition of 19.6 MMBOE of reserves compared to the year-end 2016 ASR. These additional reserves are mainly associated with the Turonian gas development and are sub-classified as Reserves Justified for Development. Once a Final Investment Decision is taken on the Aje field gas development project these reserves may become Reserves Approved for Development.

ASSUMPTIONS

The commerciality and economic tests for the Aje reserves volumes were based on an oil and condensate price of

US$60/Bbl, a LPG price of US$39/Bbl, and a gas price of US$4/MMBtu.

The commerciality and economic tests for the Dussafu reserves volumes were based on an average oil price over the field life of US$59/Bbl.

2017 – 2P DEVELOPMENT (MMBOE)

2P Reserves Development	(MMBOE)
Balance (previous ASR – December 31, 2016)	3.1
Production 2017	(0.1)
New developments since previous ASR	21.2
Revisions of previous estimates	(2.6)
Balance (revised ASR) as of December 31, 2017	**21.6**

Panoro's total 1P reserves at end of 2017 amount to 13.2 MMBOE. Panoro's 2P reserves amount to 21.6 MMBOE and Panoro's 3P reserves amount to 32.7 MMBOE. This reflects the April 2018 reserve report for the Aje field, conducted by AGR TRACS and production since the field startup, and the February 2018 reserve report for the Dussafu field, conducted by NSAI.

Panoro's Contingent Resource base includes discoveries of varying degrees of maturity towards development decisions. By end of 2017, Panoro's assets contain a total 2C volume of approximately 2.6 MMBOE.

April 30, 2018

John Hamilton
CEO

As of 31 Dec, 2017	Interest	1P (Low Estimate)				2P (Base Estimate)				3P (High Estimate)			
	%	Liquids MMbbl	Gas Bcf	Total MMBOE	Net MMBOE	Liquids MMbbl	Gas Bcf	Total MMBOE	Net MMBOE	Liquids MMbbl	Gas Bcf	Total MMBOE	Net MMBOE
On Production													
Aje Field Oil	12.1913	1.66	-	1.66	0.20	2.02	-	2.02	0.25	2.31	-	2.31	0.28
Total		**1.66**	**-**	**1.66**	**0.20**	**2.02**	**-**	**2.02**	**0.25**	**2.31**	**-**	**2.31**	**0.28**
Approved for Development													
Tortue Field	8.333	15.90	-	15.90	1.07	23.50	-	23.50	1.55	31.40	-	31.40	1.75
Total		**15.90**	**-**	**15.90**	**1.07**	**23.50**	**-**	**23.50**	**1.55**	**31.40**	**-**	**31.40**	**1.75**
Justified for Development													
Aje Field Oil	12.1913	0.50	-	0.50	0.07	0.94	-	0.94	0.14	1.76	-	1.76	0.26
Aje Field Cond.	12.1913	9.78	-	9.78	1.49	16.16	-	16.16	2.53	26.61	-	26.61	3.93
Aje Field LPG	12.1913	19.33	-	19.33	3.01	31.51	-	31.51	4.99	53.77	-	53.77	7.71
Aje Field Gas	12.1913	-	282.00	46.92	7.32	-	459.00	76.50	12.12	-	783.00	130.55	18.72
Total		**29.61**	**282.00**	**76.53**	**11.89**	**48.61**	**459.00**	**125.11**	**19.78**	**82.14**	**783.00**	**212.69**	**30.62**
Totals													
Total Reserves		**47.17**	**282.00**	**94.09**	**13.16**	**74.13**	**459.00**	**150.63**	**21.58**	**115.85**	**783.00**	**246.40**	**32.65**

Reserves Development:

2P Reserves Development	(MMBOE)
Balance (previous ASR – December 31, 2016)	3.1
Production 2017	(0.1)
Acquisitions /disposals since previous ASR	0.0
Extensions and discoveries since previous ASR	0.0
New developments since previous ASR	21.2
Revisions of previous estimates	(2.6)
Balance (revised ASR) as of December 31, 2017	**21.6**

Contingent Resources summary:

Asset	2C MMBOE (as of YE2016)	2C MMBOE (as of this report)
Aje *	28.7	1.1
Dussafu **	6.8	1.5
Totals	**35.5**	**2.6**

* The majority of Aje Contingent Resources have been re-classified as reserves in 2018.

** Panoro's share of Dussafu has changed to 8.333% from 33.333% and the majority of Tortue Contingent Resources have been re-classified as reserves in 2018.

OPERATIONS

Operations in Gabon
The Dussafu block lies at the southern end of the South Gabon sub-basin in water depths ranging from 100 – 500 metres. The Dussafu block is a Development and Exploitation license with multiple discoveries and undrilled structures lying within a proven oil and gas play fairway within the Southern Gabon Basin. Most of the block lies in less than 200 m of water and has been explored since the 1970s. To the north west of the block is the Etame-Ebouri trend, a collection of fields producing from the pre-salt Gamba and Dentale sandstones, and to the north are the Lucina and M'Bya fields which produce from the syn-rift Lucina sandstones beneath the Gamba.

A total of 20 wells have been drilled in the greater Dussafu block to date, of which five have been pre-salt discoveries (four oil and one gas) and oil shows are present in most other wells. Panoro has participated in the last two exploration wells of which both encountered hydrocarbons; Ruche (2011) and Tortue (2013).

In 2014, an Exclusive Exploitation Authorization (EEA) for an 850.5 km2 area within the Dussafu PSC was awarded. A Field Development Plan (FDP) for the EEA area was subsequently approved and a final decision to start developing the license was taken in 2017. The EEA area includes the four oil fields discovered on the license to date and numerous undrilled structures that could be economically and expeditiously developed through the EEA area development infrastructure. The EEA allows the Dussafu joint venture partners to exploit hydrocarbon resources in the area of the EEA for up to 20 years from first oil production. In 2016 the remaining portion of the greater Dussafu license area outside of the EEA area was relinquished. The first field in the EEA area, Tortue, is expected to start oil production in 2018 from two initial horizontal development wells drilled in the first half of 2018. The oil from the Tortue wells will be produced via subsea trees and flowlines to a leased FPSO for processing, storage and export. It is expected that further development and exploration drilling will follow this first phase of the development.

In February 2018, Netherland, Sewell and Associates, Inc. (NSAI) certified (3rd party) gross 1P Proved Reserves of 15.9 MMbbls in the Gamba and Dentale reservoirs of the Tortue field. Gross 2P Proved plus Probable Reserves at Tortue amounted to 23.5 MMbbls in the same reservoirs. Gross 3P Proved plus Probable plus Possible Reserves at Tortue amounted to 31.4 MMbbls.In addition to these Reserves NSAI also certified gross 1C Contingent Resources of 3.7 MMbbls and gross 2C Contingent Resources of 11.6 MMbbls in the Tortue field.

At year end Panoro's net entitlement fraction of the Gross Tortue Field Reserves, after deduction of Government share of production and royalties, was 2P Proved plus Probable Reserves of 1.55 MMbbls with additional 2C Contingent Resources of 1.5 MMbbls.

Operations in Nigeria
Covering an area of 840 km2 OML 113 is operated by Yinka Folawiyo Petroleum Limited and is located in the western part of offshore Nigeria, adjacent to the Benin border. The license contains the Aje field as well as a number of exploration prospects. The Aje field was discovered in 1996 in water depths ranging from 100-1,000m. Unlike the majority of Nigerian Fields which are productive from Tertiary age sandstones, Aje has multiple oil, gas and gas condensate reservoirs in the Turonian, Cenomanian and Albian age sandstones. Five wells have been drilled to date on the Aje field. Aje-1 and Aje-2 tested oil and gas condensate at high rates from the Turonian and Cenomanian reservoirs and Aje-4 confirmed the productivity of these reservoirs and discovered an additional deeper Albian age reservoir. Aje-5 was drilled in 2015 as a development well to produce from the Aje oil reservoirs. The OML 113 license has full 3D seismic coverage from surveys acquired in 1997 and 2014.

Production at the Aje field is underway having started in 2016. Aje currently has 2 wells on production, Aje-4 and Aje-5, which were completed as producers in the Cenomanian reservoir in 2015. Aje-5 was side-tracked and re-completed as a producer in the Turonian oil rim in 2017. Oil is processed, stored and exported at the Front Puffin FPSO via a subsea production system. These two wells comprise the first phase of the Aje field development project. During 2017 the Aje field produced a total of 113,000 barrels net to Panoro at an average rate of approximately 300 bopd net.

In July 2017, a Turonian Gas Field Development Plan (FDP) was submitted to Nigerian regulators for consideration. The FDP comprises four or five production wells in the Turonian tied back to existing and new infrastructure. The process for the renewal of the OML 113 lease in June 2018 has commenced in 2017.

In April 2018, AGR TRACS International prepared an updated CPR incorporating the 2014 seismic data, the results of the Aje side-track drilling, production history since field start-up and the development plan outlined in the Turonian gas FDP. The Aje-5 results have meant that assessment of oil reserves in the Cenomanian have been materially reduced compared to earlier estimates. However, Turonian gas, LPG and condensate have now been re-classified from contingent status to Reserves Justified for Development as a result of the FDP submission.

TRACS has now estimated gross remaining 2P and 2C resources of 136 million barrels of oil equivalent combined could be produced from the Aje field, with gross 3P and 3C resources of 233 million barrels of oil equivalent.

At year-end 2017, 2P Reserves net to Panoro's interest related to OML 113, after deduction of royalties and other adjustments, stood at 20.0 MMBOE and 2C Contingent Resources stood at 1.1 MMBOE. This is an increase in 2P reserves of 16.9 MMBOE and a decrease in 2C resources of 27.6 MMBOE compared to year-end 2016.

Operations in Brazil

In Brazil, termination agreements for the surrender of Coral and Cavalho Marinho licences have been signed between the JV partners and Brazilian Regulator ANP. The next steps involve various regulatory clearances before dissolution of JV operations. The Company's formal exit from its historical Brazilian business is still ongoing with slow progress towards the approval of abandonment by the Brazilian regulators. Management is working actively with the operator Petrobras to bring matters to a close and to ensure that the ongoing costs are kept to a minimum. However, the timing and eventual costs of such conclusion is uncertain at this stage.

THE ACCOUNTS

The Board of Directors confirms that the annual financial statements have been prepared pursuant to the going concern assumption, in accordance with §3-3a of the Norwegian Accounting Act, and that this assumption was realistic as at the balance sheet date. The going concern assumption is based upon the financial position of the Company and the development plans currently in place. In the Board of Directors' view, the annual accounts give a true and fair view of the group's assets and liabilities, financial position and results. Panoro Energy ASA is the parent company of the Panoro Group. Its financial statements have been prepared on the assumption that Panoro Energy will continue as a going concern.

The Company had USD 6.3 million in cash and bank balances as of December 31, 2017 not including USD 1.5 million cash was set aside as security of costs in relation to the dispute at Aje. Following the completion of legal formalities, funds were released back to the Company with interest post-period-end. In addition to this, commercial arrangements agreed as part of the interim settlement measures are expected to have the effect of increasing Panoro's existing revenue interest for the remainder of 2018. It is anticipated that operating costs for OML 113 will be funded in entirety from the sale of our share of Aje crude during 2018.

During the year, the Company has received USD 12 million plus some working capital adjustments at the closing of the sale of 25% interest in Dussafu permit to BWEG. The Company has in place a non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of December 31, 2017, Panoro's drawdown on the non-recourse loan was USD 2.2 million. The non-recourse loan is payable through Panoro's proceeds of the cost oil allocation in accordance with the Dussafu PSC, after paying the proportionate field operating expenses. The repayment will start at First oil on Dussafu. During the repayment phase, Panoro will still be entitled to its share of profit oil proceeds from the Dussafu operations.

The Company expects it is fully funded through the development of Phase 1 at Dussafu, from cash balances, cash flow from operations, and the non-recourse loan from BWEG. 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, and the issuance of shares. As a result, the financial statement has been prepared under the assumption of going concern and realization of assets and settlement of debt in normal operations.

Panoro Energy ASA prepares its financial statements in accordance with the International Financial Reporting Standards (IFRS), as provided for by the EU and the Norwegian Accounting Act.

The consolidated accounts are presented in US dollars.

The below analysis compares 2017 with 2016 figures:

FINANCIAL PERFORMANCE AND ACTIVITIES

Condensed Consolidated Income Statement

USD 000	2017	2016
Continuing operations		
Oil and gas revenue	6,021	5,461
Other revenue	497	-
Total revenues	**6,518**	**5,461**
Expenses		
Operating costs	(6,858)	(4,558)
Exploration related costs and operator G&A	(343)	(660)
Non-recurring dispute costs	(995)	-
General and administrative costs	(3,655)	(4,063)
Total operating expenses	**(11,851)**	**(9,281)**
EBITDA	(5,333)	(3,820)
Depreciation	(1,898)	(2,231)
Asset write-off and impairment	(28,576)	(55,795)
Share based payments	(149)	(47)
EBIT	(35,956)	(61,893)
Net financial items	(360)	(94)
Loss before taxes	(36,316)	(61,987)
Income tax benefit / (expense)	4	-
Net loss from continuing operations	(36,312)	(61,987)
Net income / (loss) from discontinued operations	(277)	(649)
Net income / (loss) for the period	**(36,589)**	**(62,636)**

From a financial statements perspective, the closure of operations in Brazil is disclosed as "discontinued operations" and as such has been reported separately from the "continuing business activities".

Income statement

Panoro Energy reported an EBITDA of negative USD 5.3 million for the year ended December 31, 2017, compared to negative USD 3.8 million in the same period in 2016.

EBITDA includes the oil and gas revenue from the four liftings from the Aje field during 2017 and the associated operating costs and the gain on the sale of a 25% stake in Dussafu.

Oil and gas revenue in the period was USD 6.0 million and is based on the Company's entitlement barrels; the revenue was generated by the sale of the net entitlement volume of 113,367 bbls. Other Income in the same period of USD 0.5 million represents the net gain on disposal of the 25% working interest in Dussafu. Oil & gas revenue in the same period of 2016 was USD 5.5 million and was generated by the sale of the net entitlement volume of 110,539 bbls.

Panoro Energy reported a net loss of USD 36.3 million from continuing operations for the year ended December 31, 2017, a decrease in loss of USD 25.9 million, compared to a loss of USD 62.0 million in the same period in 2016. The decrease in loss was a direct result of the lower impairment charges in 2017.

Operator G&A and related overheads decreased to USD 0.3 million in the year ended December 31, 2017, down from USD 0.7 million in same period in 2016.

General and Administration costs from continuing operations were USD 3.7 million for year ended December 31, 2017, down from USD 4.1 million for the same period in 2016. In 2017, USD 1.0 million of costs directly related to the Aje dispute have been reported separately as non-recurring dispute costs; there were no such costs in the same period in 2016. This amount is net of an award of USD 0.4 million reimbursement of costs pursuant to Court orders.

Depreciation for the period was USD 1.9 million decreasing from USD 2.2 million in the same period in 2016 with both periods relating to the depreciation of the Aje Cenomanian oil field. 2017 is a comparatively lower charge following an impairment exercise on Aje.

EBIT from continuing operations was thus a negative USD 36 million for the year ended December 31, 2017, compared to a negative USD 61.9 million in the same period of 2016.

Net financial items amounted to an expense of USD 360 thousand in the current period compared to an expense of USD 94 thousand in the same period in 2016. This is due to accretion of notional interest on the Aje Asset Decommissioning Liability during 2017 and finance charges.

Loss before tax from continuing activities was USD 36.3 million for the year ended December 31, 2017 compared to the loss of USD 62.0 million for the same period in 2016. The decrease in loss in 2017 is predominantly due to the inclusion of impairment provision for Aje and Dussafu in 2016.
Net loss for the period from discontinued operations in Brazil was USD 277 thousand for the period, compared to a net loss of USD 649 thousand for the same period in 2016.
The total net loss for the year ended December 31, 2017 was USD 36.6 million, compared to a net loss of USD 62.6 million for the same period in 2016.

Minor movement in respective periods to other comprehensive income was a result of currency translation adjustments for reporting purposes.

Statement of financial position

Non-current assets amounted to USD 25.4 million at December 31, 2017, a decrease of USD 26.1 million from December 31, 2016.

The overall decline in total non-current assets was a result of the sale of 25% stake in Dussafu during the period and impairment provisions, offset by capital expenditure on both the assets. Property, furniture, fixtures and equipment remained largely unchanged at USD 0.1 million.

Other non-current assets remained unchanged at USD 0.1 million for both periods and relates mainly to the tenancy deposit for office premises.

Current assets amounted to USD 9.8 million as of December 31, 2017, compared to USD 7.2 million at December 31, 2016.

Trade and other receivables stood at USD 0.6 million, a decrease from USD 1.7 million at the end of December 2016. The movement is due predominantly to the realisation of sale proceeds due for Aje's liftings during the period, offset by Panoro's portion of unspent cash held in Dussafu JV. USD 1.4 million has been accumulated and held on the balance sheet as the cash cost of Aje crude oil inventory.

Cash and cash equivalents stood at USD 6.3 million at December 31, 2017, not including USD 1.5 million cash which was released back to the Company, with interest post-period-end, having been held as collateral against dispute costs by the UK Court Funds Office. This represents an increase from USD 4.8 million cash and cash equivalents at December 31, 2016. The increase is mainly attributed to the collection of the sale proceeds relating to the disposal of 25% stake in Dussafu during the period and proceeds from the Aje liftings during the period. This has been offset by the payment of Aje cash calls of USD 4.0 million and the repurchase of 1,000,000 Panoro shares for USD 0.5 million. USD 1.5 million of Aje dispute cash collateral remains as restricted cash during the period, although released back to Company post-period-end, increasing from USD 0.5 million as at December 31, 2016.

Equity amounted to USD 17.3 million as of December 31, 2017, compared to USD 54.3 million at the end of December 2016. The change reflects the loss for the period and the effect of the repurchase of 1,000,000 Panoro shares in August 2017.

Total non-current liabilities of USD 11.1 million for the year ended December 31, 2017, compared to USD 2.0 million for the same period in 2016 including the decommissioning provision for the Aje field.

There is also the inclusion of the non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of December 31, 2017, Panoro's drawdown on the non-recourse loan was USD 2.2 million. The non-recourse loan is repayable through Panoro's allocation of the cost oil in accordance with the Dussafu PSC, after paying for the proportionate field operating expenses. The repayment will start at First Oil on Dussafu. During the repayment phase, Panoro will still be entitled to its share of profit oil, as defined in the PSC, from the Dussafu operations.

Other non-current liabilities include USD 6.8 million associated with historic cash calls on Aje, which will be settled from surplus funds, where available, from Aje crude sales after paying for current costs and liabilities.

Current liabilities amounted to USD 6.8 million at December 31, 2017, compared to USD 2.4 million at the end of December 2016.

Accounts payable, accruals and other liabilities amounted to USD 6.7 million, an increase from USD 2.3 million at the end of December 2016. The increase represents Aje operational accruals and higher corporate trade payables as at December 31, 2017. The tax liability of USD 0.1 million is in relation to historical tax liability in Brazil.

Since the settlement of the Aje dispute, the Company has performed a review of historical costs incurred and recognised the liabilities associated with such expenditures in the balance sheet. The proportionate joint venture liabilities resulting from the workover and side-tracks at Aje-5 have been higher than anticipated and as such have resulted in proportional liabilities of USD 6.1 million as of December 31, 2017. Such liabilities are current in nature and are expected to be repaid in full by the end of financial year 2018. In addition to these, USD 6.8 million is classified as long-term liabilities which as per the terms agreed between OML 113 Joint Venture partners, certain transitional arrangements were introduced whereby unpaid cash calls will not be immediately payable. During the transition period, any excess funds from Panoro's entitlement of crude liftings after paying for its share of operating expenditure shall be used to repay unpaid cash calls. In addition to this, commercial arrangements agreed as part of the interim settlement measures are expected to have the effect of increasing Panoro's existing revenue interest for the remainder of 2018. It is anticipated that operating costs for OML 113 will be funded in entirety from the sale of our share of Aje crude during 2018.

Cash flows

Net cash flow from operating activities amounted to negative USD 2.0 million in 2017, compared to negative USD 2.6 million in 2016. The decline is primarily explained by lower costs throughout 2017 brought about by cost saving initiatives introduced by Management.

Net cash flow from investing activities was an inflow of USD 5.1 million in 2017, compared to an outflow of USD 11.8 million in 2016. The net cash inflow in 2017 mainly relates to the disposal of a 25% stake in Dussafu, offset by investment in oil and gas assets.

Net cash flow from financing activities represented a cash outflow of USD 1.6 million in 2017, predominantly comprising USD 1.0 million of movement in restricted cash where USD 1.5 million was held as collateral against our dispute at Aje, however funds were returned to the Company post-period end. In addition to this, the Company purchased 1,000,000 of its own shares for approximately USD 0.5 million. This compares to a cash inflow in 2016 of USD 8.3 million, where proceeds from the Equity Private Placement of USD 8.8 million were offset by USD 520 thousand of restricted cash, held in connection with the dispute at Aje.

Foreign exchange impact on cash balances was a positive USD 30 thousand in 2017 and a negative USD 33 thousand in 2016.

Cash and cash equivalents thus increased to USD 6.3 million (2016: USD 4.8 million).

ALLOCATION OF PROFITS AND LOSSES

Parent company financial information

(Amounts in USD 000)	**2017**	**2016**
Total revenues	-	-
Operating expenses		
Depreciation	-	-
General and administrative costs	(1,751)	(1,249)
Impairment of investment in subsidiary	(335)	(38,873)
Provision for Doubtful Receivables	(32,885)	(28,311)
Write-down of Intercompany balances	-	-
Total operating expenses	(34,971)	(68,433)
Earnings before interest and tax (EBIT)	(34,971)	(68,433)
Net interest and financial items	9,293	10,048
Loss before taxes	(25,678)	(58,385)
Income tax benefit / (expense)	-	-
Net loss	(25,678)	(58,385)

FUNDING

During the year, the Company has received USD 12 million plus some working capital adjustments at the closing of the sale of 25% interest in Dussafu permit to BWEG. The Company has in place a non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of December 31, 2017, Panoro's drawdown on the non-recourse loan was USD 2.2 million. The non-recourse loan is payable through Panoro's proceeds of the allocated cost oil in accordance with the Dussafu PSC, after paying the proportionate field operating expenses. The repayment will start at first oil production at Dussafu. During the repayment phase, Panoro will still be entitled to the proceeds of its entire share of profit oil from the Dussafu operations. Consequently, Panoro is likely to receive free cash flow.

Since the settlement of the dispute with the OML 113 partners, USD 1.5 million of collateral is no longer required and has been released back to the Company on completion of legal formalities. In addition to this, commercial arrangements agreed as part of the interim settlement measures are expected to have the effect of increasing Panoro's existing revenue interest for the remainder of 2018. It is anticipated that operating costs for OML 113 will be funded in entirety from the sale of our share of Aje crude during 2018.

The Company expects it is fully funded through the development of Phase 1 at Dussafu, from cash balances, cash flow from operations, and the non-recourse loan from BWEG. 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, and the issuance of shares. As a result, the financial statement has been prepared under the assumption of going concern and realization of assets and settlement of debt in normal operations.

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 licenses 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. As a non-operator, the Company has limited influence on operational risks related to exploration and development of the licenses and fields in which it has interests.

The development of the oil and gas fields, in which the Group has an ownership, is associated with significant technical risk and uncertainty with regards to timing of additional production from new development activities. Risks include, but are not limited to, cost overruns, production disruptions as well as delays compared to initial plans laid out by the operator. Some of the most important risk factors are related to the determination of reserves, the recoverability of reserves, and the planning of a cost efficient and suitable production method. There are also technical risks present in the production phase that may cause cost overruns, failed investment and destruction of wells and reservoirs.

The Company's license in Nigeria OML 113 is due for renewal during the year 2018. Although, the license renewal is expected to be customary, a near-term expiry exposes the Group to short-term uncertainty.

As the Company is exiting Brazil there are potential tax liabilities related among others to the divestment of Rio das Contas. In addition, there are uncertainties related to the final environmental costs of BS-3 licenses.

The Company'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.

Financial risk factors

Financial risk is managed by the finance department under policies approved by the Board of Directors. The overall risk management program seeks to minimize the potential adverse effects of unpredictable fluctuations in financial and commodity markets on financial performance, i.e., risks associated with currency exposures, debt servicing and oil and gas prices. 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 Company is exposed to risk arising from currency exposure, primarily with respect to the Norwegian Kroner (NOK), the US Dollar (USD), and, to a lesser extent, the Pound Sterling (GBP) and Brazilian Reals (BRL). Most of the cash balance is held in USD with banking institutions of high quality credit ratings and the currency risk exposure is very limited.

The Company has access to a non-recourse loan facility of upto USD 12.5 million from BWEG and as a result is subject to interest rate risk. The Company's cash holdings and bank balances are held in various currencies in different countries and are subject to interest rate risk and credit risk.

The Company has received USD 12 million plus some working capital adjustments on closing of the sale of 25% interest in Dussafu permit to BWEG. As a result and including anticipated cash flow from operations, the Group's liquidity situation has significantly improved. The Company expects it is fully funded through the development of Phase 1 at Dussafu, from cash balances, cash flow from operations, and the non-recourse loan from BWEG. 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, and the issuance of shares. As a result, the financial statement has been prepared under the assumption of going concern and realization of assets and settlement of debt in normal operations.

Panoro has been entertaining discussions with a number of third parties having expressed interests to purchase part or all of its interests in OML 113. However there can be no assurances that any transaction contemplated under these discussions will be consummated.

For risk factors pertaining to the Company and its operations, reference is also made to the prospectus dated March 11, 2016 which is available on the Company's website.

ORGANISATION AND HEALTH, SAFETY AND ENVIRONMENT (HSE)

The management of the Company is led by CEO John Hamilton. Mr. Hamilton has considerable experience from various positions in the international oil and gas industry. He is supported by CFO, Qazi Qadeer and Technical Director, Richard Morton, both are also based in London.

Since the beginning of 2017, Panoro Energy has been employing 5 individuals (including part-time employees), all of which are based in London.

The Company emphasizes the importance of maintaining a good working environment in order to achieve Company goals and objectives. The objective is to create a constructive working environment characterized by a spirit where employees' ideas and initiatives are welcome, founded on mutual trust between employees, management and the Board of Directors.

Health, Safety and Environment (HSE) policies are essential for Panoro with the goal to avoid accidents and incidents and minimize the impact of its activities on the environment. Panoro 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 Company's objective for health, environment, safety and quality (HSEQ) is zero accidents and zero unwanted incidents in all activities. The Company strives towards performing all its activities with no harm to people or the environment. Panoro experienced no major accidents, injuries, incidents or any environmental claims during the year.

Company time lost due to employee illness or accidents was less than 1 per cent of total hours worked during the year. Employee safety is of the highest priority, and company policies imply continuous work towards identifying and employing administrative and technical solutions that ensure a safe and efficient work-place.

The Company has established 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 may mean frequent travel, and the Company seeks to ensure adequate safety levels for employees travelling. An emergency preparedness organization has been established, in which membership in International SOS is a key factor. International SOS provides updated risk assessments, medical support and evacuation services worldwide.

As a non-operator, Panoro is dependent on the efforts of the operators with respect to achieving physical results in the field. However, the Company 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 Company can influence the choice of technical solutions, vendors and quality of applied procedures and practices.

The Company's operations have been conducted by the operators on behalf of the licensees, at acceptable HSE standards. No accidents that resulted in loss of human lives or serious damage to people or property have been reported.

Panoro Energy is committed to work towards minimising waste and pollution as a consequence of its activities. Operations are centralised in the London office and as such, travel requirements have been greatly reduced.

As described above, all operating activities are being conducted by operators on behalf of the Company, and to the best of the Company's knowledge, all operations have been conducted within the limits set by approved environmental regulatory authorities.

CORPORATE GOVERNANCE

The main objective for Panoro Energy ASA's Corporate Governance is to develop a strong, sustainable, competitive and a successful E&P company acting in the best interest of all the stakeholders, within the laws and regulations of the respective countries. 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.

Panoro Energy acknowledges that successful value-added business is profoundly dependent upon transparency and internal and external confidence and trust. Panoro Energy believes that this is achieved by building a solid reputation based on our financial performance, our values and by fulfilling our commitments. Thus, good corporate governance practices combined with Panoro Energy's Code of Conduct is an important tool in assisting the Board to ensure that we properly discharge our duty.

The composition of the Board ensures that the Board represents the common interests of all shareholders and meets the Company's need for expertise, experience, capacity and diversity. The members of the Board represent a broad range of experience including oil and gas, energy, banking and investment. The composition of the Board ensures that it can operate independently of any special interests. Members of the Board are elected for a period of two years. Recruitment of members of the Board will be phased so that the entire Board is not replaced at the same time. The Chairman of the Board of Directors is elected by the General Meeting.

The Board may be given power of attorney by the General Meeting to acquire the Company's own shares. Any acquisition of shares will be carried out through a regulated marketplace at market price, and the Company will not deviate from the principle of equal treatment of all shareholders. If there is limited liquidity in the Company's share at the time of such transaction, the Company will consider other ways to ensure equal treatment of all shareholders.

The Board may also be given a power of attorney by the General Meeting to issue new shares for specific purposes. Any decision to deviate from the principle of equal treatment by waiving the pre-emption rights of existing shareholders to subscribe for shares in the event of an increase in share capital will be justified and disclosed in the stock exchange announcement of the increase in share capital. Such deviation will be made only if it is in the common interest of the shareholders and the Company.

The Company has not granted any loans or guarantees to anyone in the management or any of the directors.

The Board acknowledges the Norwegian Code of Practice for Corporate Governance and the principle of comply or explain. Panoro Energy has implemented this Code and uses its guidelines as the basis for the Board's governance duties. A report on the corporate governance policy is incorporated in a separate section of this report and is also posted on the Company's website at www.panoroenergy.com.

The Company has implemented a policy for Ethical Code of Conduct and work diligently to comply with these guidelines. The full policy is enclosed in this annual report (see section Ethical Code of Conduct).

DISCRIMINATION AND EQUAL EMPLOYMENT OPPORTUNITIES

Panoro Energy is an equal opportunity employer, with an equality concept integrated in its human resources policies. A diversified working environment is embraced, and the Company'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 Panoro Energy's Code of Conduct, to ensure uniformity in behaviour across a workforce representing 3 different nationalities.

Panoro Energy is a knowledge-based company 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.

80% of the employees were men and 20% women at the end of 2017 and 2016. There are currently no women in Panoro Energy's senior management.

DIRECTORS AND SHAREHOLDERS

According to its articles of association, the Company shall have a minimum of three and a maximum of eight directors on its Board. The number of Board members was five at year end 2017, all non-executive directors. The members have various backgrounds and experience, offering the Company valuable perspectives on industrial, operational and financial issues. Two of the five Board members as at year end 2017 are female. The Board held 8 meetings during the year.

REPORTING OF PAYMENT TO GOVERNMENTS

Panoro Energy has prepared a report of government payments in accordance with Norwegian Accounting Act § 3-3 d) and accordance with Norwegian Securities Trading Act § 5-5a. It states that companies engaged in activities within the extractive industries shall annually prepare and publish a report containing information about their payments to governments at country and project level.

The report is provided on page 90 of this annual report and on Company's website www.panoroenergy.com.

OUTLOOK

Panoro looks forward to 2018, where it can build and capitalise on a landmark partnership with BWO and achieving production from Dussafu Development. At Aje, Panoro's efforts will be directed towards moving the Turonian gas development forward, renewal of the license and progressing any strategic solutions for OML 113. Panoro's balanced, full cycle E&P portfolio provides the platform to consider opportunities to grow the asset base.

The Board wishes to thank the staff and shareholders for their continued commitment to the Company.

April 30, 2018
The Board of Directors
Panoro Energy ASA

Julien Balkany *Chairman of the Board*	Garrett Soden *Non-Executive Director*	Torstein Sanness *Non-Executive Director*
Alexandra Herger *Non-Executive Director*	Hilde Ådland *Non-Executive Director*	John Hamilton *Chief Executive Officer*

BOARD OF DIRECTORS

JULIEN BALKANY

Chairman of the Board

Mr. Julien Balkany, Chairman of the Board, is a French citizen resident in London, has been serving as a managing partner of Nanes Balkany Partners, a group of investment funds headquartered in New York and which primarily pursues active value investments in publicly traded oil and gas companies gas companies since 2008. Concomitantly, Mr. Balkany is also non-executive Director of two mining companies, Sarmin Bauxite Ltd. and Pan-African Diamonds limited. Mr. Balkany has been from March 2015 to May 2016 a non-executive Director of Norwegian Energy Company ASA (Noreco), a Norwegian exploration and production company listed on the Oslo Stock Exchange and focused on the North Sea. Mr. Balkany has been from May 2014 to July 2015 a non-executive Director of Gasfrac Energy Services Inc., a Canadian oil and gas fracking services company. From January 2009 to March 2011, Mr. Balkany served as Vice-Chairman and non-executive Director of Toreador Resources Corp., an oil and gas exploration and production company with operations in Continental Europe (France, Turkey, Hungary and Romania) that was dual-listed on the US NASDAQ and Euronext Paris. Mr. Balkany has been a Managing Director at Nanes Delorme Capital Management LLC, a New York based financial advisory and broker-dealer firm, where he executed several hundred million dollars' worth of oil & gas M&A transactions. Before joining Nanes Delorme, Mr. Balkany worked at Pierson Capital and gained significant experience at Bear Stearns. Mr. Balkany studied at the Institute of Political Studies (Strasbourg) and at UC Berkeley. Mr. Balkany is fluent in French, English and Spanish.

ALEXANDRA HERGER

Non-Executive Director

Ms. Alexandra (Alex) Herger, a US citizen based in Maine, has extensive senior leadership and board experience in worldwide exploration and production for international oil and gas companies. Ms. Herger has 39 years of global experience in the energy industry, currently serving as an Independent director for Tortoise Capital Advisors, CEFs, based in Leawood, Kansas, Tethys Oil based in Stockholm, Sweden, as well as Panoro Energy. Her most recent leadership experience was as interim Vice President for Marathon Oil Company until her retirement in July 2014. Prior to this position, Ms. Herger was Director of International Exploration and New Ventures for Marathon Oil Company from 2008 - 2014, where she led five new country entries and was responsible for adding net discovered resources of over 500 million boe to the Marathon portfolio. Ms. Herger was at Shell International and Shell USA from 2002-2008, holding positions as Exploration Manager for the Gulf of Mexico, Manager of Technical Assurance for the Western Hemisphere, and Global E & P Technical Assurance Consultant. Prior to the Shell / Enterprise Oil acquisition in 2002, Ms. Herger was Vice President of Exploration for the Gulf of Mexico for Enterprise Oil, responsible for the addition of multiple giant deep water discoveries. Earlier, Ms. Herger held positions of increasing responsibility in oil and gas exploration and production, operations, and planning with Hess Corporation and Exxonmobil Corporation. Ms. Herger holds a Bachelor's Degree in Geology from Ohio Wesleyan University and post-graduate studies in Geology from the University of Houston. Ms. Herger is a member of Leadership Texas, the foundation for women's resources, and was on the advisory board of the Women's Global Leadership Conference in Houston, Texas from 2010 to 2013.

GARRETT SODEN

Non-Executive Director

Mr. Garrett Soden has extensive experience as a senior executive and board member of various public companies in the natural resources sector. He has worked with the Lundin Group for over a decade. Mr. Soden is currently President and CEO of Africa Energy Corp., a Canadian oil and gas exploration company focused on Africa. He is also a Non-Executive Director of Etrion Corporation, Gulf Keystone Petroleum Ltd., Petropavlovsk plc and Phoenix Global Resources plc. Previously, he was Chairman and CEO of RusForest AB, CFO of Etrion and PetroFalcon Corporation and a Non-Executive Director of PA Resources AB. Prior to joining the Lundin Group, Mr. Soden worked at Lehman Brothers in equity research and at Salomon Brothers in mergers and acquisitions. He also previously served as Senior Policy Advisor to the U.S. Secretary of Energy. Mr. Soden holds a BSc honours degree from the London School of Economics and an MBA from Columbia Business School.

HILDE ÅDLAND

Non-Executive Director

Mrs. Hilde Ådland, a Norwegian citizen, and has extensive technical experience in the oil and gas industry. She has leadership experience in field development, engineering, commissioning, and field operations. Mrs. Ådland is currently Asset Manager for Gjøa and Vega for Neptune Energy in Norway (previously Engie E&P Norges as and GDF SUEZ E&P Norge as). She held several senior positions with Engie/GDF SUEZ in Norway including production and development manager and senior facility engineer. Prior to joining GDF in 2008, she spent 12 years with Statoil in a number of senior engineering and operational roles, including Offshore Installation Manager, and 5 years with Kvaerner. In autumn 2015 she was also elected chairman in the Operation Committee within the Norwegian Oil and Gas Association. She has a Bachelor's degree in chemical engineering and a Master's degree in process engineering.

TORSTEIN SANNESS

Non-Executive Director

Mr. Torstein Sanness, a Norwegian Citizen residing in Norway has extensive experience and technical expertise in the oil and gas industry. Mr. Sanness became the Chairman of Lundin Petroleum Norway in April 2015. Prior to this position Mr. Sanness was Managing Director of Lundin Petroleum Norway from 2004 to April 2015. Under his leadership Lundin Norway has turned into one of the most successful players on the NCS and added net discovered resources of close to a billion boe to its portfolio through the discoveries of among others E. Grieg and Johan Sverdrup. Before joining Lundin Norway Mr. Sanness was Managing Director of Det Norske Oljeselskap AS (wholly owned by DNO at the time) and was instrumental in the discoveries of Alvheim, Volund and others. From 1975 to 2000, Mr. Sanness was at Saga Petroleum until its sale to Norsk Hydro and Statoil, where he held several executive positions in Norway as well as in the US, including being responsible for Saga's international operations and entry into Libya, Angola, Namibia, and Indonesia. Currently Mr. Sanness is serving as board member of International Petroleum Corp. (a Lundin Group E&P company with portfolio of assets in Canada, Europe and South East Asia), Sevan Marine ASA, (a specialised marine engineering and design house), and TGS (the world's largest geoscience data company). Mr. Sanness is a graduate of the Norwegian Institute of Technology in Trondheim where he obtained a Master of Engineering (geology, geophysics and mining engineering).

SENIOR MANAGEMENT

JOHN HAMILTON

Chief Executive Officer

John Hamilton, Chief Executive Officer, has considerable experience from various positions in the international oil and gas industry. Most recently, John was Chief Executive Officer of UK AIM listed President Energy PLC, a Latin American focused exploration company, which opened up a new onshore basin in Paraguay. Before joining President, John was Managing Director of Levine Capital Management, and oil and gas investment fund. He was also Chief Financial Officer of UK FTSE 250 listed Imperial Energy PLC, until its sale for over US$ 2 billion in 2008. John also spent 15 years with ABN AMRO Bank in Europe, Africa, and the Middle East. The majority of his time with ABN AMRO was spent in the energy group, with a principal focus on financing upstream oil and gas. John has a BA from Hamilton College in New York, and an MBA from the Rotterdam School of Management and New York University.

QAZI QADEER

Chief Financial Officer

Qazi Qadeer, Chief Financial Officer is a Chartered Accountant with a Fellow membership of Institute of Chartered Accountants of Pakistan. Qazi joined Panoro at its inception in 2010 as Group Finance Controller. Previously he has worked for PriceWaterhouseCoopers in Karachi, Pakistan and briefly served as Internal audit manager in Pak-Arab Refinery before relocating to London, where he has spent more than five years with Ernst & Young's energy and extractive industry assurance practice; working on various projects for large and small oil & gas and mining companies. He has worked on several high profile projects including the divestment of BP plc's chemicals business in 2005 and IPO of Gem Diamonds Limited in 2006. He is a British citizen and resides in London, UK.

RICHARD MORTON

Technical Director

Richard Morton, Technical Director has 25 years of experience in exploration, production, development and management in the oil and gas industry. Originally a highly qualified geophysicist, he has expanded his portfolio of skills progressively into operational and asset management. He has worked in a number of challenging contracting and operating environments, including as Centrica Energy's Exploration Manager for Nigeria. He has been with Panoro Energy since 2008 with responsibilities for project and technical management of Panoro's African exploration and development assets. Richard obtained a B.Sc. in Physics from Essex University in 1989 and went on to complete a M.Sc. in Applied Geophysics from the University of Birmingham the following year. He is a British citizen and resides in London, UK.

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CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

For the year January 1, 2017 to December 31, 2017

USD 000	Note	2017	2016
CONTINUING OPERATIONS			
Revenue			
Oil and gas revenue	3	6,021	5,461
Other revenue		497	-
Total revenue		**6,518**	**5,461**
Expenses			
Operating costs	3	(6,858)	(4,558)
Exploration related costs and operator G&A		(343)	(660)
Non-recurring dispute costs		(995)	-
General and administrative costs	4	(3,655)	(4,063)
Impairment / reversal of Impairment of assets	9D	(28,576)	(55,795)
Depreciation	9	(1,898)	(2,231)
Share based payments	16	(149)	(47)
Total operating expenses		**(42,474)**	**(67,354)**
Operating loss	4	**(35,956)**	**(61,893)**
Net foreign exchange (loss) / gain		30	(33)
Interest costs net of income	5	(254)	43
Other financial costs	5	(136)	(104)
Loss before income taxes		**(36,316)**	**(61,987)**
Income tax benefit / (expense)	6	4	-
Net loss from continuing operations		**(36,312)**	**(61,987)**
DISCONTINUED OPERATIONS			
Net income / (loss) from discontinued operations	12	(277)	(649)
Net loss for the period		**(36,589)**	**(62,636)**
Exchange differences arising from translation of foreign operations		(3)	(10)
Other comprehensive income / (loss) for the period (net of tax)		**(3)**	**(10)**
Total comprehensive income / (loss)		**(36,592)**	**(62,646)**
Net loss attributable to:			
Equity holders of the parent		(36,589)	(62,636)
Total comprehensive income / (loss) attributable to:			
Equity holders of the parent		(36,592)	(62,646)
Earnings per share	7		
(USD) – Basic and diluted – Income / (loss) for the period attributable to equity holders of the parent – Total		(0.86)	(1.61)
(USD) – Basic and diluted – Income / (loss) for the period attributable to equity holders of the parent – Continuing operations		(0.85)	(1.60)

The annexed notes form an integral part of these financial statements.

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31, 2017

USD 000	Note	2017	2016
ASSETS			
Non-current assets			
Intangible assets			
Licenses and exploration assets	8	13,596	25,971
Total intangible assets		**13,596**	**25,971**
Tangible assets			
Production assets and equipment	9	9,902	25,285
Development assets	8	1,694	-
Property, furniture, fixtures and equipment	9	102	169
Other non-current assets	9	134	122
Total tangible assets		**11,832**	**25,576**
Total non-current assets		**25,428**	**51,547**
Current assets			
Crude oil inventory		1,398	163
Trade and other receivables	10	615	1,724
Cash and cash equivalents	11	6,317	4,768
Restricted cash	11	1,500	520
Total current assets		**9,830**	**7,175**
TOTAL ASSETS		**35,258**	**58,722**
EQUITY AND LIABILITIES			
Equity			
Share capital	14	299	305
Share premium		297,490	297,503
Treasury shares	14	(503)	-
Additional paid-in capital		122,205	122,101
Total paid-in equity		**419,491**	**419,909**
Other reserves	14	(43,405)	(43,404)
Retained earnings		(358,766)	(322,177)
Total equity attributable to shareholder of the parent		**17,320**	**54,328**
Non-current liabilities			
Decommissioning liability	13	2,039	1,925
Long-term liabilities	15	2,197	-
Other long-term liabilities	15	6,892	88
Total non-current liabilities		**11,128**	**2,013**
Current liabilities			
Accounts payable and accrued liabilities	15	6,737	2,287
Corporate tax liability		73	94
Total current liabilities		**6,810**	**2,381**
TOTAL EQUITY AND LIABILITIES		**35,258**	**58,722**

The annexed notes form an integral part of these financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

As at December 31, 2017

		Attributable to the equity holders of the parent							
USD 000	**Note**	**Issued capital**	**Share premium**	**Treasury shares**	**Additional paid-in capital**	**Retained earnings**	**Other reserves**	**Currency translation reserve**	**Total**
At January 1, 2016		**193**	**288,858**	**-**	**122,054**	**(259,539)**	**(37,647)**	**(5,748)**	**108,171**
Net income / (loss) – Continuing Operations		-	-	-	-	(61,987)	-	-	(61,987)
Net income / (loss) – Discontinued Operations		-	-	-	-	(649)	-	-	(649)
Other comprehensive income / (loss)		-	-	-	-	-	-	(10)	(10)
Total comprehensive income / (loss)		-	-	-	-	(62,636)	-	(10)	(62,646)
Share Issue for cash		112	9,294	-	-	-	-	-	9,406
Transaction costs on Share Issue		-	(650)	-	-	-	-	-	(650)
Employee share based incentives	16	-	-	-	47	-	-	-	47
At December 31, 2016		**305**	**297,503**	**-**	**122,101**	**(322,177)**	**(37,647)**	**(5,758)**	**54,328**
At January 1, 2017		**305**	**297,503**	**-**	**122,101**	**(322,177)**	**(37,647)**	**(5,758)**	**54,328**
Net income / (loss) – Continuing Operations		-	-	-	-	(36,312)	-	-	(36,312)
Net income / (loss) – Discontinued Operations		-	-	-	-	(277)	-	-	(277)
Other comprehensive income/(loss)		-	-	-	-	-	-	(3)	(3)
Total comprehensive income / (loss)		-	-	-	-	(36,589)	-	(3)	(36,592)
Purchase of own shares		(6)	-	(503)	-	-	-	-	(509)
Transaction costs on share buy back		-	(13)	-	-	-	-	-	(13)
Employee share based incentives	16	-	-	-	149	-	-	-	149
Employee share options grant charge / (benefit)		-	-	-	(44)	-	-	-	(44)
At December 31, 2017		**299**	**297,490**	**(503)**	**122,206**	**(358,766)**	**(37,647)**	**(5,761)**	**17,320**

The annexed notes form an integral part of these financial statements.

CONSOLIDATED CASH FLOW STATEMENT

For the year ended December 31, 2017

USD 000	Note	2017	2016
Cash flows from operating activities			
Net (loss) / income for the year before tax – Continuing operations		(36,316)	(61,987)
Net (loss) / income for the year before tax – Discontinued operations		(203)	(514)
Net (loss) / income for the year before tax		**(36,519)**	**(62,501)**
Adjusted for:			
Depreciation		1,898	2,231
Exploration related costs and Operator G&A		343	660
Impairment and asset write off		28,576	56,566
Net finance costs		390	61
Share-based payments		149	47
Foreign exchange loss / (gain)		(30)	33
Increase / (decrease) in trade and other payables		4,084	1,657
(Increase) / decrease in trade and other receivables		463	(1,188)
(Increase) / decrease in oil inventory		(1,235)	(163)
Taxes paid		(71)	(41)
Net cash flows from operating activities		**(1,952)**	**(2,638)**
Cash flows from investing activities			
Proceeds from disposal of Assets		12,737	-
Investment in exploration, production and other assets		(7,685)	(12,617)
Movement in related non-current assets		-	813
Net cash flows from financing activities		**5,052**	**(11,804)**
Cash flows from financing activities			
Own shares buy back		(509)	-
Net proceeds from Equity Private Placement		-	8,774
Net financial income (net of charges paid)		(65)	18
Movement in restricted cash balance		(980)	(520)
Net cash flows from financing activities		**(1,554)**	**8,272**
Effect of foreign currency translation adjustment on cash balances		3	(10)
Change in cash and cash equivalents during the period		**1,549**	**(6,180)**
Cash and cash equivalents at the beginning of the period		4,768	10,948
Cash and cash equivalents at the end of the period		**6,317**	**4,768**

The annexed notes form an integral part of these financial statements.

NOTE 1. CORPORATE INFORMATION

The parent company, Panoro Energy ASA ("the Company"), was incorporated on April 28, 2009 as a public limited company under the Norwegian Public Limited Companies Act. The registered organization number of the Company is 994 051 067 and its registered office is c/o Michelet & Co Advokatfirma AS, Grundingen 3, 0250 Oslo, Norway.

The Company and its subsidiaries ("Panoro" or the "Group") are engaged in the exploration and production of oil and gas resources in West Africa. The consolidated financial statements of the Group for the year ended December 31, 2017 were authorised for issue by the Board of Directors on April 30, 2018.

The Board of Directors confirms that the annual financial statements have been prepared pursuant to the going concern assumption, in accordance with §3-3a of the Norwegian Accounting Act, and that this assumption was realistic as at the balance sheet date. The going concern assumption is based upon the financial position of the Company and the development plans currently in place. In the Board of Directors' view, the annual accounts give a true and fair view of the group's assets and liabilities, financial position and results. Panoro Energy ASA is the parent company of the Panoro Group. Its financial statements have been prepared on the assumption that Panoro Energy will continue as a going concern.

The Company had USD 6.3 million in cash and bank balances as of December 31, 2017 not including USD 1.5 million cash was set aside as security of costs in relation to the dispute at Aje. Following the completion of legal formalities, funds were released back to the Company with interest post-period-end. In addition to this, commercial arrangements agreed as part of the interim settlement measures are expected to have the effect of increasing Panoro's existing revenue interest for the remainder of 2018. It is anticipated that operating costs for OML 113 will be funded in entirety from the sale of our share of Aje crude during 2018.

During the year, the Company has received USD 12 million plus some working capital adjustments at the closing of the sale of 25% interest in Dussafu permit to BWEG. The Company has in place a non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of December 31, 2017, Panoro's drawdown on the non-recourse loan was USD 2.2 million. The non-recourse loan is payable through Panoro's proceeds of the allocated cost oil in accordance with the Dussafu PSC, after paying the proportionate field operating expenses. The repayment will start at First oil on Dussafu. During the repayment phase, Panoro will still be entitled to its share of profit oil proceeds from the Dussafu operations.

The Company expects it is fully funded through the development of Phase 1 at Dussafu, from cash balances, cash flow from operations, and the non-recourse loan from BWEG. 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, and the issuance of shares. As a result, the financial statement has been prepared under the assumption of going concern and realization of assets and settlement of debt in normal operations. However, there are uncertainties related to this assessment.

The Company's shares are traded on the Oslo Stock Exchange under the ticker symbol PEN.

NOTE 2. BASIS OF PREPARATION

The consolidated financial statements of the Group have been prepared in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union ("EU"). The consolidated financial statements are prepared on a historical cost basis, except for certain financial instruments which have been measured at fair value.

The principal accounting policies applied in the preparation of these consolidated financial statements are set out below. These policies have been consistently applied to all years presented, unless otherwise stated.

The consolidated financial statements are presented in USD, which is the functional currency of Panoro Energy ASA. The amounts in these financial statements have been rounded to the nearest USD thousand unless otherwise stated.

NOTE 2.1 BASIS OF CONSOLIDATION

The consolidated financial statements include Panoro Energy ASA and its subsidiaries as of December 31 for each year.

Subsidiaries are fully consolidated from the date of acquisition, being the date on which the Group obtains control, and continue to be consolidated until the date that such control ceases.

The financial statements of the subsidiaries are prepared for the same reporting period as the parent company, using consistent accounting policies.

All intra-group balances, transactions and unrealised gains and losses resulting from intra-group transactions and dividends are eliminated in full.

Non-controlling interests in subsidiaries are identified separately from the Group's equity therein. Total comprehensive income is attributed to non-controlling interests even if this results in the non-controlling interests having a deficit balance.

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 NCI
- derecognises the cumulative translation differences recognised 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 other comprehensive income to profit or loss or retained earnings, as appropriate.

The purchase method of accounting is applied for business combinations. The cost of the acquisition is measured as the aggregate of the fair values, at the date of exchange, of assets given, liabilities incurred or assumed, and equity instruments issued by the acquirer, in exchange for control of the acquirer.

If the initial accounting for a business combination can only be determined provisionally, then provisional values are used. However, these provisional values may be adjusted within 12 months from the date of the combination.

NOTE 2.2 SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

a. Estimates and assumptions
The preparation of the financial statements in conformity with IFRS as adopted by the EU requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities and contingent liabilities at the date of the consolidated financial statements and reported amounts of revenues and expenses during the reporting period. Estimates and judgments are continuously evaluated and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. However, actual outcomes can differ from these estimates.

In particular, significant areas of estimation uncertainty considered by management in preparing the consolidated financial statements are as follows:

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 Group estimates and reports hydrocarbon reserves in line with the principles contained in the SPE Petroleum Resources Management Reporting System (PRMS) framework and generally obtains independent evaluations for each asset whenever new information becomes available that materially influences the reported results. 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 exploration and evaluation assets; oil and gas properties; property, plant and equipment; and goodwill may be affected due to changes in estimated future cash flows
- 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
- Provisions for decommissioning may change – where changes to the reserve estimates affect expectations about when such activities will occur and the associated cost of these activities
- The recognition and carrying value of deferred tax assets may change due to changes in the judgements regarding the existence of such assets and in estimates of the likely recovery of such assets

Exploration and evaluation expenditures
The application of the Group's accounting policy for exploration and evaluation expenditure requires judgement to determine whether future economic benefits are likely, from future either exploitation or sale, or whether activities have not reached a stage which permits a reasonable assessment of the existence of reserves. The determination of reserves and resources is itself an estimation process that requires varying degrees of uncertainty depending on how the resources are classified. These estimates directly impact when the Group defers exploration and evaluation expenditure. The deferral policy requires management to make certain estimates and assumptions about future events and circumstances, in particular, whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after expenditure is capitalised, information becomes available suggesting that the recovery of the expenditure is unlikely, the relevant capitalised amount is written off in the statement of profit or loss and other comprehensive income in the period when the new information becomes available.

Income taxes
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.

b. Judgments
In the process of applying the Group's accounting policies, the directors have made the following judgments, apart from those involving estimates, which have the most significant effect on the amounts recognised in the consolidated financial statements:

Dispute and litigation
On November 2, 2017, Panoro announced that its subsidiary Pan Petroleum Aje Limited ("PPAL") had entered into a binding agreement with the other OML 113 joint-venture partners. The agreement in conjunction with other initiatives addresses a number of operational and financial issues. Under the terms of the agreement, certain transitional arrangements were introduced whereby unpaid cash calls will not be immediately payable. Such unpaid cash calls are included in the long-term payable balance as of the end of the quarter. During the transition period, any excess funds from Panoro's entitlement of crude liftings shall be used to pay operational costs incurred in the JV, any remaining liabilities and unpaid cash calls. In addition to this, commercial arrangements agreed as part of the settlement measures are expected to have the effect of increasing PPAL's existing revenue interest until approximately the end of 2018.

On January 2, 2018, post period end, Panoro announced that PPAL had entered into a definitive and binding settlement agreement (the "Agreement") with the other OML 113 joint-venture partners. The Agreement resolved and settled the dispute between the OML 113 joint-venture partners in relation to drilling of new development wells.

The highlights of the Agreement included:

- All OML 113 joint-venture partners have agreed to halt and withdraw all litigation and arbitration proceedings among the partners;

- PPAL would not pay for any Aje-6 costs that have been incurred by the JV, until such time as the equipment and parts are to be used in any potential future well operations;
- Substantial court costs already awarded to PPAL to be retained and any remaining balances credited in favour of PPAL; and
- PPAL's USD 1.5 million cash security deposit held with UK Courts Funds Office would be released and returned to it. PPAL completed the formalities post-period end and funds have been returned.

Impairment indicators
The Group assesses each cash-generating unit annually to determine whether an indication of impairment exists. When an indication of impairment exists, a formal estimate of the recoverable amount is made.

The recoverable amounts of cash-generating units and individual assets have been determined based on the higher of value-in-use calculations and fair values less costs to sell, or if relevant, a combination of these two models. These calculations require the use of estimates and assumptions. It is reasonably possible that the oil price assumption may change which may then impact the estimated life of the field and may then require a material adjustment to the carrying value of tangible assets. The Group monitors internal and external indicators of impairment relating to its tangible and intangible assets.

Technical risk in development of oil and gas fields
The development of the oil and gas fields, in which the Group has an ownership, is associated with significant technical risk and uncertainty with regards to timing of additional production from new development activities. Risks include, but are not limited to, cost overruns, production disruptions as well as delays compared to initial plans laid out by the operator. Some of the most important risk factors are related to the determination of reserves, the recoverability of reserves, and the planning of a cost efficient and suitable production method. There are also technical risks present in the production phase that may cause cost overruns, failed investment and destruction of wells and reservoirs.

Judgements have been made after taking into account information available to management and factors in unknown uncertainties as of the date of the balance sheet.

Asset retirement obligations
Asset retirement 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 asset retirement 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 asset retirement obligation. 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 asset retirement costs required.

Contingencies
By their nature, contingencies will only be resolved when one or more future events occur or fail to occur. The assessment of contingencies inherently involves the exercise of significant judgment and estimates of the outcome of future events.

NOTE 2.3 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

a. Interests in joint arrangements
A joint arrangement is an arrangement over which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities (being those that significantly affect the returns of the arrangement) require unanimous consent of the parties sharing control.

(i) Joint operations
A joint operation is a type of joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets and obligations for the liabilities, relating to the arrangement.

In relation to its interests in joint operations, the Group 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
- Expenses, including its share of any expenses incurred jointly

(ii) Joint ventures
A joint venture is a type of joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the joint arrangement. The Group's investment in its joint venture is accounted for using the equity method.

Under the equity method, the investment in the joint venture is initially recognised at cost. The carrying amount of the investment is adjusted to recognise changes in the Group's share of net assets of the joint venture since the acquisition date. Goodwill relating to the joint venture is included in the carrying amount of the investment and is not individually tested for impairment.

The statement of profit or loss reflects the Group's share of the results of operations of the joint venture. Unrealised gains and losses resulting from transactions between the Group and the joint venture are eliminated to the extent of the interest in the joint venture.

The aggregate of the Group's share of profit or loss of the joint venture is shown on the face of the statement of profit or loss and other comprehensive income as part of operating profit and represents profit or loss after tax and NCI in the subsidiaries of the joint venture.

The financial statements of the joint venture are prepared for the same reporting period as the Group. When necessary, adjustments are made to bring the accounting policies in line with those of the Group.

At each reporting date, the Group determines whether there is objective evidence that the investment in the joint venture is impaired. If there is such evidence, the Group calculates the amount of impairment as the difference between the recoverable amount of the joint venture and its carrying value, and then recognises the loss as 'Share of profit of a joint venture' in the statement of profit or loss and other comprehensive income.

On loss of joint control over the joint venture, the Group measures and recognises any retained investment at its fair value. Any difference between the carrying amount of the joint venture upon loss of joint control and the fair value of the retained investment and proceeds from disposal is recognised in the statement of profit or loss and other comprehensive income.

(iii) Reimbursement of costs of the operator of the joint arrangement

When the Group, acting as an operator or manager of a joint arrangement, receives reimbursement of direct costs recharged to the joint arrangement, such recharges represent reimbursements of costs that the operator incurred as an agent for the joint arrangement and therefore have no effect on profit or loss.

When the Group charges a management fee (based on a fixed percentage of total costs incurred for the year) to cover other general costs incurred in carrying out the activities on behalf of the joint arrangement, it is not acting as an agent. Therefore, the general overhead expenses and the management fee are recognised in the statement of profit or loss and other comprehensive income as an expense and income, respectively.

b. Foreign Currency translation

Items included in the financial statements of each of the Group's entities are measured using the currency of the primary economic environment in which the entity operates ('the functional currency').

The functional currency of the Group's subsidiaries incorporated in Gabon, Nigeria, Cyprus, Netherlands and the Cayman Islands is the US dollar ('USD'). The functional currency of the Group's Brazilian subsidiaries is Reais ('BRL') and for the British subsidiaries is the Pound Sterling ('GBP').

In the consolidated financial statements, the assets and liabilities of non-USD functional currency subsidiaries are translated into USD at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-USD functional currency subsidiaries are translated into USD using applicable average rates as an approximation for the exchange rates prevailing at the dates of the different transactions. Foreign exchange adjustments arising when the opening net assets and the profits for the year retained by non-USD functional currency subsidiaries are translated into USD are taken to a separate component of equity.

The foreign exchange rates applied were:

	2017		2016	
	Average rate	Reporting date rate	Average rate	Reporting date rate
Norwegian Kroner / USD	8.2654	8.1993	8.3998	8.6051
Brazilian Real / USD	3.1922	3.3077	3.4830	3.2588
USD / British Pound	1.2888	1.3510	1.3542	1.2303

Transactions in foreign currencies are initially recorded at the functional currency spot rate ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated at the functional currency spot rate of exchange ruling at the reporting date. All differences are taken to the income statement. Non-monetary items that are measured in terms of historical cost in foreign currency are translated using the spot exchange rates as at the dates of the initial transactions. 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.

c. 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 IAS 39 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 IAS 39, it is measured in accordance with the appropriate IFRS. Contingent consideration that is classified as equity is not re-measured, 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.

d. License interests, exploration and evaluation assets, and field investments, and depreciation

The Group applies the 'successful efforts' method of accounting for Exploration and Evaluation ('E&E') costs, in accordance with IFRS 6 'Exploration for and Evaluation of Mineral Resources'. E&E expenditure is capitalised when it is considered probable that future economic benefits will be recoverable. Costs that are known at the time of incurrence to fail to meet this criterion are generally charged to expense in the period they are incurred.

E&E expenditure capitalised as intangible assets includes license acquisition costs, and exploration drilling, geological and geophysical costs and any other directly attributable costs.

E&E expenditure, which is not sufficiently related to a specific mineral resource to support capitalization, is expensed as incurred.

E&E assets are carried forward, until the existence, or otherwise, of commercial reserves have been determined subject to certain limitations including review for indications of impairment. If no reserves are found the costs to drill exploratory wells, including exploratory geological and geophysical costs and costs of carrying and retaining unproved properties, are written off.

Once commercial reserves have been discovered, the carrying value after any impairment loss of the relevant E&E assets is transferred to development tangible and intangible assets. No depreciation and/or amortisation are charged during the exploration and development phase. If however, commercial reserves have not been discovered, the capitalised costs are charged to expense after the conclusion of appraisal activities.

Development tangible and intangible assets
Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of commercially proven development wells, is capitalised within property, plant and equipment and intangible assets according to nature. When development is completed on a specific field, it is transferred to production assets. No depreciation or amortisation is charged during the Exploration and Evaluation phase.

Farm-outs – in the exploration and evaluation phase
The Group does not record any expenditure made by the farmee on its account. It also does not recognise any gain or loss on its exploration and evaluation farm-out arrangements, but redesignates any costs previously capitalised in relation to the whole interest as relating to the partial interest retained. Any cash consideration received directly from the farmee is credited against costs previously capitalised in relation to the whole interest with any excess accounted for by the farmor as a gain on disposal.

Development costs
Expenditure on the construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, is capitalised within oil and gas properties.

Oil & gas production assets
Development and production assets are accumulated on a cash-generating unit basis and represent the cost of developing the commercial reserves discovered and bringing them into production together with E&E expenditures incurred in finding commercial reserves transferred from intangible E&E assets as outlined in accounting policy above.

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/amortisation
Oil and gas properties and intangible assets are depreciated or amortised using the unit-of-production method. Unit-of-production rates are based on proved and probable 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.

Depreciation/amortisation on assets held for sale is ceased from the date of such classification.

Impairment – exploration and evaluation assets
E&E assets are assessed for impairment when facts and circumstances suggest that the carrying amount exceeds the recoverable amount and when they are reclassified to PP&E assets. For the purpose of impairment testing, E&E assets are grouped by concession or field with other E&E and PP&E assets belonging to the same CGU. The impairment loss will be calculated as the excess of the carrying value over recoverable amount of the E&E impairment grouping and any resulting impairment loss is recognized in profit or loss. The recoverable amount of a CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. In assessing fair value less costs to sell, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risk specific to the asset. Fair value less costs to sell is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Impairment – proved oil and gas production properties and intangible assets
Proven oil and gas properties and intangible assets are reviewed annually for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The carrying value is compared against the expected recoverable amount of the asset, generally by net present value of the future net cash flows, expected to be derived from production of commercial reserves or consideration expected to be achieved through the sale of its interest in an arms-length transaction, less any associated costs to sell. The cash generating unit applied for impairment test purposes is generally the field, except that a number of field interests may be grouped together where there are common facilities.

e. Non-current assets held for sale or for distribution to equity holders of the parent and discontinued operations
The Group classifies non-current assets and disposal groups as held for sale or for distribution to equity holders of the parent if their carrying amounts will be recovered principally through a sale or distribution rather than through continuing use. Such non-current assets and disposal groups classified as held for sale or as held for distribution are measured at the lower of their carrying amount and fair value less costs to sell or to distribute. Costs to distribute are the incremental costs directly attributable to the distribution, excluding the finance costs and income tax expense.

The criteria for held for distribution classification is regarded as met only when the distribution is highly probable and the asset or disposal group is available for immediate distribution in its present condition. Actions required to complete the distribution should indicate that it is unlikely that significant changes to the distribution will be made or that the distribution with be withdrawn. Management must be committed to the distribution expected within one year from the date of the classification. Similar considerations apply to assets or a disposal group held for sale.

Production assets, property, plant and equipment and intangible assets are not depreciated or amortised once classified as held for sale or as held for distribution.

Assets and liabilities classified as held for sale or for distribution are presented separately as current items in the statement of financial position.

A disposal group qualifies as discontinued operation if it is:
- a component of the Group that is a CGU or a group of CGUs
- classified as held for sale or distribution or already disposed in such a way, or
- a major line of business or major geographical area.

Discontinued operations are excluded from the results of continuing operations and are presented as a single amount as profit or loss after tax from discontinued operations in the statement of profit or loss.

f. Financial assets
Initial recognition and measurement
Financial assets are classified, at initial recognition, as financial assets at fair value through profit or loss, loans and receivables, held-to-maturity investments, restricted cash, available-for-sale (AFS) financial assets, or derivatives designated as hedging instruments in an effective hedge, as appropriate. All financial assets are recognised initially at fair value plus, in the case of financial assets not recorded at fair value through profit or loss, transaction costs that are attributable to the acquisition of the financial asset.

Purchases or sales of financial assets that require delivery of assets in a timeframe established by regulation or convention in the market place (regular way trades) are recognised on the trade date, i.e., the date at which the Group commits to purchase or sell the asset.

The Group's financial assets include cash and cash equivalents and certain trade and other receivables.

Subsequent measurement
For purposes of subsequent measurement financial assets are classified into four categories:
- Financial assets at fair value through profit or loss
- Trade and other receivables
- Held-to-maturity investments – the Group has no held-to-maturity investments
- AFS financial investments – the Group has no AFS financial assets

Financial assets at fair value through profit or loss
Financial assets at fair value through profit or loss include financial assets held for trading and financial assets designated upon initial recognition at fair value through profit or loss. Financial assets are classified as held for trading if they are acquired for the purpose of selling or repurchasing in the near term. Derivatives, including separated embedded derivatives, are also classified as held for trading unless they are designated as effective hedging instruments, as defined by IAS 39. Financial assets at fair value through profit or loss are carried in the statement of financial position at fair value with net changes in fair value presented as finance costs (negative changes in fair value) or finance revenue (positive net changes in fair value) in

the statement of comprehensive income. The Group has not designated any financial assets at fair value through profit or loss.

Derivatives embedded in host contracts are accounted for as separate derivatives and recorded at fair value if their economic characteristics and risks are not closely related to those of the host contracts and the host contracts are not held for trading or designated at fair value though profit or loss. These embedded derivatives are measured at fair value, with changes in fair value recognised in the statement of profit or loss and other comprehensive income. Reassessment occurs only if there is a change in the terms of the contract that significantly modifies the cash flows that would otherwise be required or there is a reclassification of a financial asset out of the fair value through profit or loss category. The group has no embedded derivatives as of December 31, 2016 and December 31, 2017.

Trade and other receivables
This category is most relevant to the Group. Trade and other receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, such financial assets are subsequently measured at amortised cost using the effective interest rate method, less impairment. 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 effective interest rate. The effective interest rate amortisation is included in finance income in the statement of profit or loss and other comprehensive income. The losses arising from impairment are recognised in the statement of profit or loss and other comprehensive income in finance costs for loans and in cost of sales or other operating expenses for receivables.

Cash and cash equivalents
Cash and cash equivalents includes cash at hand, and deposits held on call with banks. Cash balances in current accounts, short-term deposits and placement with maturity of six months or less in highly liquid investments are classified as cash and cash equivalents.

Impairment of financial assets
The Group assesses at each reporting date whether a financial asset or group of financial assets are impaired. Details of impairment principles for financial assets is included in note 2.5(q).

g. Financial liabilities
Initial recognition and measurement
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 and derivative financial liabilities.

The Group's financial liabilities include trade and other payables, and loans and borrowings.

Subsequent measurement
The measurement of financial liabilities depends on their classification, as described below:

Trade payables
Trade payables are recognised initially at fair value and subsequently measured at amortised cost using the effective interest method.

Loans and borrowings
All borrowings are initially recorded at fair value. Interest-bearing loans and overdrafts are initially recorded at the proceeds received, net of directly attributable issue costs. Finance charges, including premiums payable on settlement or redemption and direct issue costs, are accounted for on an accruals basis in the income statement using the effective interest method and are added to the carrying amount of the instrument to the extent that they are not settled in the period in which they arise.

Under the requirements of IAS 39 AG8, any revisions to the estimates of payments or receipts in relation to a financial instrument are adjusted to reflect the actual and revised estimated cashflows. The change in estimated cashflows are remeasured by computing the present value of estimated cashflows at the financial instrument's original effective interest rate. The adjustment is recognised in the statement of comprehensive income as Income or expense.

h. 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.

i. Asset retirement obligation

An asset retirement 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 asset retirement, discounted to its present value. Changes in the estimated timing of asset retirement or asset retirement 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 asset retirement provision is included as a finance cost.

j. Income tax

Income tax expense represents the sum of the tax currently payable and movement in deferred tax.

Current tax

Current income tax assets and liabilities for the current and prior periods are measured at the amount expected to be recovered from or paid to the taxation authorities. The tax rates and tax laws used to compute the amount are those that are enacted or substantively enacted by the reporting date, in the countries where the Group operates and generates taxable income.

Current income tax relating to items recognised directly in equity is recognised in equity and not in the income statement. Management periodically evaluates positions taken in the tax returns with respect to situations which applicable tax regulations are subject to interpretation and established provisions where appropriate.

Deferred tax

Deferred tax is provided using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred income tax liabilities are recognised for all taxable temporary differences, except:

- Where the deferred tax liability arises from the initial recognition of goodwill or of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affect neither the accounting profit nor taxable profit or loss; and
- In respect of taxable temporary differences associated with investments in subsidiaries, associates and interest in joint ventures, where the timing of the reversal of the temporary differences can be controlled and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognised for all deductible temporary differences; carry forward to unused tax credits and unused tax losses, to the extent that it is probable that future taxable profit will be available against which the deductible temporary differences and the carry forward of unused tax credits and unused tax losses can be utilized except:

- Where the deferred income tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither the accounting profit nor taxable profit or loss; and
- In respect of deductible temporary differences associate with investments in subsidiaries, associate and interest in joint ventures, deferred income tax assets are recognised only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each reporting date and reduced to the extent that it is no longer probable that sufficient future taxable profit will be available to allow all or part of the deferred tax asset to be utilized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profit will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply to the year when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the reporting date.

Deferred tax relating to items recognized directly in equity is recognized in equity and not in the income statement.

Deferred tax assets and deferred tax liabilities are offset, if a legally enforceable right exists to set off current tax assets against current tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

Tax benefits acquired as part of a business combination, but not satisfying the criteria for separate recognition at that date, would be recognised subsequently if new information about facts and circumstances arose. The adjustment would either be treated as a reduction to goodwill (as long as it does not exceed goodwill) if it occurred during the measurement period or in profit or loss.

Production-sharing arrangements
According to the production-sharing arrangement (PSA) in certain licenses, 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 Group to the appropriate tax authorities. This portion of income tax and revenue are presented net in income statement.

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.

k. Revenue recognition
Revenue from petroleum products
Revenue from the sale of petroleum products is recognized as income using the "entitlement method". Under this method, revenue is recorded on the basis of the asset's proportionate share of total crude, gas and NGL produced from the affected fields. Revenue is stated net of value-added tax and royalties.

Revenue from test production is recognised as a direct off-set to the capitalised cost of the exploration and evaluation asset.

Interest income and financial instruments measured at amortised cost
Interest income is recognized on an accruals basis. For all financial instruments measured at amortised cost and interest-bearing financial assets classified as available for sale, interest income or expense is recorded using the effective interest rate (EIR), which is the rate that exactly discounts the estimated future cash payments or receipts through the expected life of the financial instrument or a shorter period, where appropriate, to the net carrying amount of the financial asset or liability. Interest revenue is included in finance income in income statement.

Rendering of services
Sales of services are recognized in the accounting period in which the services are rendered, and it is probable that the economic benefits associated with the transaction will flow to the entity, by reference to completion of the specific transaction assessed on the basis of the actual service provided as a proportion of the total services to be provided.

l. Leases
The determination of whether an arrangement is, or contains, a lease is based on the substance of the arrangement at inception date: whether fulfilment or the arrangement is dependent on the use of a specific asset or assets or the arrangement conveys a right to use the asset.

For arrangements entered into prior to January 1, 2005, the date of inception is deemed to be January 1, 2005 in accordance with the transitional requirements of IFRIC 4.

Group as a lessee
Finance leases, which transfer to the Group substantially all the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Lease payments are apportioned between finance charges and reduction of the lease liability so as to achieve a constant rate of interest on the remaining balance of the liability. Finance charges are reflected in the income statement.

Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset and the lease term, if there is no reasonable certainty that the Group will obtain ownership by the end of the lease term.

Operating lease payments are recognized as an expense in the income statement on a straight line basis over the lease term.

m. Property, plant and equipment
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%

n. Defined contribution pension plan
The Group pays contributions into a defined contribution plan. Obligations for contributions to defined contribution pension plans are recognised as an expense in the income statement in the periods during which services are rendered by employees.

o. Share-based payment transactions
Employees (including senior executives) of the Group may receive remuneration in the form of share-based payment transactions, whereby employees render services as consideration for equity instruments (equity-settled transactions).

Equity-settled transactions
The cost of equity-settled transactions is recognised, together with a corresponding increase in additional paid in capital reserve in equity, over the period in which the performance and/or service conditions are fulfilled. The cumulative expense recognised for equity-settled transactions at each reporting date until the vesting date reflects the extent to which the vesting period has expired and the Group's best estimate of the number of equity instruments that will ultimately vest. The income statement expense or credit for a period represents the movement in cumulative expense recognised as at the beginning and end of that period and is recognised in share-based payments expense.

No expense is recognised for awards that do not ultimately vest, except for equity-settled transactions for which vesting are conditional upon a market or non-vesting condition. These are treated as vesting irrespective of whether or not the market or non-vesting condition is satisfied, provided that all other performance and/or service conditions are satisfied.

When the terms of an equity-settled transaction award are modified, the minimum expense recognised is the expense as if 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.

When an equity-settled award is cancelled, it is treated as if it vested on the date of cancellation, and any expense not yet recognised for the award is recognised immediately. This includes any award where non-vesting conditions within the control of either the entity or the employee are not met. However, if a new award is substituted for the cancelled award, and designated as a replacement award on the date that it is granted, the cancelled and new awards are treated as if they were a modification of the original award, as described in the previous paragraph.

The dilutive effect of outstanding options is reflected as additional share dilution in the computation of diluted earnings per share.

p. 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 of disposal 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

For assets and liabilities that are recognised in the financial statements on a recurring basis, the Group determines whether transfers have occurred between levels in the hierarchy by reassessing categorisation (based on the lowest-level input that is significant to the fair value measurement as a whole) at the end of each reporting period.

For the purpose of fair value disclosures, the Group has determined classes of assets and liabilities based on the nature, characteristics and risks of the asset or liability and the level of the fair value hierarchy as explained above.

q. Impairments of non-oil and gas interests

Non-financial assets

Assets that are subject to amortisation or depreciation are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Goodwill is assessed for impairment on an annual basis. An impairment loss is recognised for the amount by which the asset's carrying amount exceeds its recoverable amount. The recoverable amount is the higher of an asset's fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. For the purposes of assessing impairment, assets are grouped at the lowest levels for which there are separately identifiable cash inflows (cash-generating units). Non-financial assets that were previously impaired are reviewed for possible reversal of the impairment at each reporting date.

A previously recognised impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognised. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognised for the asset in prior years. Such a reversal is recognised in the income statement. After such a reversal the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

Financial assets

Assets carried at amortised cost

If there is objective evidence that an impairment loss on assets carried at amortised cost has been incurred, the amount of the loss is measured as the difference between the assets' carrying amount and the present value of estimated future cash flows (excluding future expected credit losses that have not been incurred) discounted at the financial asset's original effective interest rate (ie the effective interest rate computed at initial recognition). The carrying amount of the asset is reduced through use of an allowance account. The amount of the loss shall be recognised in the income statement.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognised, the previously recognised impairment loss is reversed, to the extent that the carrying value of the asset does not exceed its amortised cost at the reversal date, any subsequent reversal of an impairment loss is recognised in the income statement.
In relation to trade receivables, a provision for impairment is made when there is objective evidence (such as the probability of insolvency or significant financial difficulties of the debtor) that the Group will not be able to collect all of the amounts due under the original terms of the invoice. The carrying amount of the receivable is reduced through use of an allowance account. Impaired debts are derecognised when they are assessed as uncollectible.

r. 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.

NOTE 2.4 NEW AND AMENDED STANDARDS AND INTERPRETATIONS

There were a number of amended standards and interpretations, effective from January 1, 2017 that the Group applied for the first time in the current year. Several other amendments apply for the first time in 2017; however, they do not impact the annual consolidated financial statements of the Group. The nature and the impact of each new relevant standard and/or amendment that may have an impact on the Group now or in the future is described below. Other than the changes described below, the accounting policies adopted are consistent with those of the previous financial year.

IAS 7 Statement of Cash Flow
The objective of IAS 7 is to require the presentation of information about the historical changes in cash and cash equivalents of the Group by means of a statement of cash flows, which classifies cash flows during the period according to operating, investing and financing activities. The amendments are intended to clarify IAS 7 to improve information provided to users of financial statements about the Group's financing activities. They are effective for annual periods beginning on or after 1 January 2017, with earlier application being permitted.

IFRS 12 Disclosure of Interests in Other Entities
IFRS 12 is a consolidated disclosure standard requiring a wide range of disclosures about the Group's interests in subsidiaries, joint arrangements, associates and unconsolidated 'structured entities'. Disclosures are presented as a series of objectives, with detailed guidance on satisfying those objectives. The objective of IFRS 12 is to require the disclosure of information that enables users of financial statements to evaluate:

- the nature of, and risks associated with, its interests in other entities
- the effects of those interests on its financial position, financial performance and cash flows.

Where the disclosures required by IFRS 12, together with the disclosures required by other IFRSs, do not meet the above objective, the Group is required to disclose whatever additional information is necessary to meet the objective.

IAS 12 Income Taxes
The objective of IAS 12 is to prescribe the accounting treatment for income taxes. In meeting this objective, IAS 12 notes the following:

- It is inherent in the recognition of an asset or liability that that asset or liability will be recovered or settled, and this recovery or settlement may give rise to future tax consequences which should be recognised at the same time as the asset or liability
- The Group should account for the tax consequences of transactions and other events in the same way it accounts for the transactions or other events themselves.

NOTE 2.5 STANDARDS ISSUED BUT NOT YET EFFECTIVE

The standards and interpretations that are issued but not yet effective up to the date of issuance of the Group's financial statements are discussed below. These are the changes the Group reasonably expects will have an impact on disclosures, financial position or performance when applied at a future date. The Group intends to adopt these standards and interpretations, if applicable, when they become effective.

IFRS 9 Financial Instruments
In July 2014, the IASB issued the final version of IFRS 9 Financial Instruments which reflects all phases of the financial instruments project and replaces IAS 39 Financial Instruments: Recognition and Measurement and all previous versions of IFRS 9. The standard introduces new requirements for classification and measurement, impairment, and hedge accounting. IFRS 9 is effective for annual periods beginning on or after January 1, 2018, with early application permitted, and was endorsed by the EU in November 2016. Retrospective application is required, but comparative information is not compulsory. Early application of previous versions of IFRS 9 (2009, 2010 and 2013) is permitted if the date of initial application is before February 1, 2015. The Company does not believe the adoption of IFRS 9 will have any impact as it does not have any financial assets that would be affected by the new standard.

IFRS 15 Revenue from Contracts with Customers
IFRS 15 was issued in May 2014 and establishes a new five-step model that will apply to revenue arising from contracts with customers. Under IFRS 15, revenue is recognized at an amount that reflects the consideration to which an entity expects to be entitled in exchange for transferring goods or services to a customer.

The principles in IFRS 15 provide a more structured approach to measuring and recognising revenue. The new revenue standard is applicable to all entities and will supersede all current revenue recognition requirements under IFRS. Either a full or modified retrospective application is required for annual periods beginning on or after January 1, 2018 with early adoption permitted, and was endorsed by the EU in September 2016. There have been some early indicators that the entitlement method currently applied by the company will not be allowed under IFRS 15, but this has not yet been concluded. The company has assessed the impact of IFRS 15 and considers there to be no impact due to the fact that the partners share liftings and therefore there is no over / underlift. The Company recognises the revenue when the risk and reward passess to the customer. The Company plans to adopt the new standard on the required effective date.

IFRS 16 Leasing
On January 13, 2016, the IASB issued IFRS 16 Leases ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded. Having been endorsed by the EU in October 2017, IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 Revenue From Contracts With Customers has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The new standard changes introduce a single on-balance sheet accounting model for all leases, which will result in the recognition of a lease liability and a right of use asset in the balance sheet. The Company is currently evaluating the impact of adopting these standards on its consolidated financial statements, which will see all current and any future leased vessels or rigs being capitalised in the Company's balance sheet.

The Group has not early adopted any other standard, interpretation or amendment that was issued but is not yet effective.

NOTE 3. OPERATING SEGMENTS

From 2014, the Group operated predominantly in one business segment being the exploration of oil and gas in West Africa. After the Company took a decision to cease all operations in Brazil, the segment has been classified as a discontinued operation. Details of discontinued operations can be referred to in note 12. As such, the segment information for December 31, 2017 does not include Brazilian operations. However, for the purpose of comparative information, the Brazilian segment has been included.

The Group's reportable segments, for both management and financial reporting purposes, are as follows:

- The West African segment holds the following assets:
  - The Dussafu licence representing the Group's 8.333% working interest in the Dussafu Marin exploration licence in Gabon.
  - The OML113-Aje represents the Group's 16.255% paying interest (12.1913% revenue interest) in the OML113-Aje exploration licence in Nigeria.
- The 'Corporate and others' category consists of head office and service company operations that are not directly attributable to the other segment.
- Management monitors the operating results of business segments separately for the purpose of making decisions about resources to be allocated and of assessing performance. Segment performance is evaluated based on capital and general expenditure after disposal of subsidiary in Brazil. Details of group segments are reported below.

Details of Group segments are reported below.

2017 USD 000	West Africa	Corporate	Total – Continuing operations	Brazil – Discontinued operations	Total
Revenue (net) *	6,518	-	6,518	-	6,518
EBITDA	(790)	(4,543)	(5,333)	(74)	(5,407)
Depreciation	(1,828)	(70)	(1,898)	-	(1,898)
Impairment	(28,576)	-	(28,576)	-	(28,576)
Profit / (loss) before tax	(34,423)	(1,893)	(36,316)	(203)	(36,519)
Net profit / (loss)	**(34,423)**	**(1,889)**	**(36,312)**	**(277)**	**(36,589)**
Segment assets **	29,675	5,452	35,127	131	35,258
– Additions to licenses, exploration and evaluation assets, development assets	16,435	-	16,435	-	16,435

2016 USD 000	West Africa	Corporate	Total – Continuing operations	Brazil – Discontinued operations	Total
Revenue (net)	5,461	-	5,461	-	5,461
EBITDA	(49)	(3,771)	(3,820)	(103)	(3,923)
Depreciation	(2,134)	(97)	(2,231)	-	(2,231)
Impairment	(55,608)	-	(55,608)	(419)	(56,027)
Profit / (loss) before tax	(60,286)	(1,701)	(61,987)	(514)	(62,501)
Net profit / (loss)	**(60,286)**	**(1,701)**	**(61,987)**	**(514)**	**(62,501)**
Segment assets	52,698	5,901	58,599	123	58,722
– Additions to licenses, exploration and evaluation assets, development assets	13,503	-	13,503	-	13,503

* Revenue excludes any intercompany revenue.

** Segment assets for Discontinued Operations as at December 31, 2017 relate to USD 127 thousand, Cash and USD 4 thousand, Other Receivables (December 31, 2016 USD 4 thousand, Cash and USD 119 thousand, Other Receivables).

Revenue from major sources from continuing operations:

USD 000	2017	2016
Oil revenue (net)	6,021	5,461
Other income	497	-
Total Revenue (net)	**6,518**	**5,461**

There are no differences in the nature of measurement methods used on segment level compared with the consolidated financial statements.

NOTE 4. OPERATING PROFIT

Operating profit is stated after charging / (crediting):

USD 000	Note	2017	2016
Employee benefits expense		1,548	1,571
Depreciation	9	1,898	2,231
Impairment and asset write-off	9, 12	28,576	56,027
Operating lease payments		228	241

NOTE 4A. EMPLOYEE BENEFIT EXPENSES

General and administrative expenses include wages, employers' contribution and other compensation as detailed below:

USD 000	2017	2016
Salaries	1,217	1,228
Employers contribution	156	153
Pension costs	104	114
Other compensation	71	76
Total	**1,548**	**1,571**

The number of employees in the Group as at year end is detailed below:

	2017	2016
Number of employees	5	5

NOTE 4B. BOARD OF DIRECTORS STATEMENT ON REMUNERATION OF EXECUTIVES

Statement for the current year (2017)
In accordance with the Norwegian Public Limited Liability Companies Act §6-16a, the Board of Directors must prepare a statement on remuneration of executives. This statement can be referred to on page 78 of this report.

NOTE 4C. MANAGEMENT REMUNERATION

Executive management has in previous years, consisted of the Chief Executive Officer (CEO), Chief Financial Officer (CFO) and Chief Operating Officer (COO). Current Executive management remuneration is summarized below:

2017	**Short term benefits**						
USD 000 (unless stated otherwise)	**Salary**	**Bonus**	**Benefits**	**Pension costs**	**Total**	**Number of RSUs awarded in 2017**	**Fair value of RSUs expensed**
John Hamilton, CEO	380	94	8	36	518	200,000	64
Qazi Qadeer, CFO	227	43	4	22	296	100,000	32
Richard Morton, Technical Director	239	45	4	23	311	80,000	26
Total	**846**	**182**	**16**	**81**	**1,125**	**380,000**	**122**

2016	**Short term benefits**						
USD 000 (unless stated otherwise)	**Salary**	**Bonus**	**Benefits**	**Pension costs**	**Total**	**Number of RSUs awarded in 2016**	**Fair value of RSUs expensed**
John Hamilton, CEO	372	74	7	37	490	100,000	21
Qazi Qadeer, CFO	225	45	4	22	296	50,000	10
Richard Morton, Technical Director	239	24	4	24	290	40,000	8
Total	**836**	**143**	**15**	**83**	**1,076**	**190,000**	**39**

(i) Under the terms of employment, the CEO in general is required to give at least six month's written notice prior to leaving Panoro; the CFO and Technical Director in general are required to give at least three month's written notice prior to leaving Panoro.

(ii) Per the respective terms of employment, the CEO is entitled to 12 months of base salary in the event of a change of control; whereby a tender offer is made or consummated for the ownership of more than 50% or more of the outstanding voting securities of the Company; or the Company is merged or consolidated with another corporation and as a result of such merger or consolidation less than 50.1% of the outstanding voting securities of the surviving entity or resulting corporation are owned in the aggregate by the persons, by the entities or persons who were shareholders of the Company immediately prior to such merger or consolidation; or the Company sells substantially all of its assets to another corporation that is not a wholly owned subsidiary. The CFO and Technical Director are entitled to 6 months of base salary in the event of a change of control.

(iii) In June 2017, 420,000 Restricted Share Units (RSU) were awarded under the Company's RSU scheme to employees of the Company under the long term incentive compensation plan approved by the shareholders, of which 380,000 units were awarded to Executive Management. One RSU entitles the holder to receive one share of capital stock of the Company against payment in cash of the par value of the share. The par value is currently NOK 0.05 per share. Vesting of the RSUs is time based. The standard vesting period is 3 years, where 1/3 of the RSUs vest after one year, 1/3 vest after 2 years and the final 1/3 vest after 3 years from grant. RSUs vest automatically at the respective vesting dates and the holder will be issued the applicable number of shares as soon as possible thereafter.

(iv) All salaries, bonuses and benefit payments have been expensed as incurred.

(v) All bonuses were approved by the Board of Directors.

Refer to note 16 for further information on the Restricted Share Units scheme.

NOTE 4D. BOARD OF DIRECTORS REMUNERATION

The remuneration of the members of the Board is determined on a yearly basis by the Company at its annual general meeting. The directors may also be reimbursed for, inter alia, travelling, hotel and other expenses incurred by them in attending meetings of the directors or in connection with the business of Panoro Energy ASA. A director who has been given a special assignment, besides his/her normal duties as a director of the Board, in relation to the business of Panoro Energy ASA may be paid such extra remuneration as the directors may determine.

Remuneration to members of the Board of Directors is summarized below:

USD 000	2017	2016
Julien Balkany (Chairman of the Board of Directors)	68	66
Alexandra Herger	39	38
Garrett Soden	39	38
Torstein Sanness	39	38
Hilde Ådland (i)	39	28
Total	**224**	**208**

The Chairman of the Board of Directors' annual remuneration is NOK 450,000. The remaining Directors' annual remuneration is NOK 225,000. All Board Members also form the Audit Committee and Remuneration Committee for which they each receive NOK 50,000 annually per committee. No loans have been given to, or guarantees given on the behalf of, any members of the Management Group, the Board or other elected corporate bodies.

(i) Pursuant to an Extraordinary General Meeting held on March 2, 2016, Hilde Ådland was elected to the Board of Directors with an effective date of April 1, 2016 to take the Board composition to five members.

NOTE 4E. PENSION PLAN

The Company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("Lov om obligatorisk tjenestepensjon"). The Company contributes to an external defined contribution scheme and therefore no pension liability is recognized in the statement of financial position. As of December 2017, the Company had no employees at parent company level and this pension plan is no longer in operation.

In the UK, the Company's subsidiary that employs the staff, contributes a fixed amount per Company policy in an external defined contribution scheme. As such, no pension liability is recognised in the statement of financial position in relation to Company's subsidiaries either.

Refer to Note 4a for the contributions made to the external defined scheme for 2017 and 2016.

NOTE 4F. AUDITORS' REMUNERATION

Fees, excluding VAT, to the auditors are included in general and administrative expense and are shown below:

USD 000	2017	2016
Ernst & Young		
Statutory audit	93	181
Tax services	-	-
Other	-	-
Total	**93**	**181**

NOTE 5. FINANCE INCOME, INTEREST EXPENSE AND OTHER CHARGES

Interest costs net of (income) / expense

USD 000	2017	2016
Interest income from placements and deposits	(33)	(52)
Other financial costs	423	113
Total – Net (income) / expense	**390**	**61**

NOTE 6. INCOME TAX

Income tax
The major components of income tax in the consolidated statement of comprehensive income are. The income tax disclosures below include items from both continuing and discontinued operations:

USD 000	2017	2016
Income Taxes		
Current income tax – continuing and discontinued operations	-	-
Deferred income tax	-	-
Tax charge / (benefit) for the period	**-**	**-**

A reconciliation of the income tax expense applicable to the accounting profit before tax at the statutory income tax rate to the expense at the Group's effective income tax rate is as follows:

USD 000	2017	2016
(Loss) before taxation – continuing	(36,316)	(61,987)
Profit / (Loss) before taxation – discontinued operations	(277)	(649)
Profit / (Loss) before taxation – Total	**(36,593)**	**(62,636)**
Tax calculated at domestic tax rates applicable to profits in the respective countries	(9,754)	(17,902)
Expenses not deductible	8,197	2,244
Differences due to functional currency effects in subsidiaries	-	-
Tax effect of losses not utilised in the period	1,588	15,658
Prior year adjustment	(4)	-
Tax charge / (benefit)	**27**	**-**

Deferred tax
The analysis of deferred tax assets and deferred tax liabilities is as follows:

USD 000	2017	2016
Deferred tax assets		
– to be reversed within 12 months	-	-
– to be reversed after more than 12 months	-	-
Total deferred tax assets	**-**	**-**
Deferred tax liabilities		
– to be reversed within 12 months	-	-
– to be reversed after more than 12 months	-	-
Total deferred tax liabilities	**-**	**-**
Net deferred tax assets / (liabilities)	**-**	**-**

The gross movement on the deferred income tax account is as follows:

USD 000	2017	2016
As at January 1	-	-
Movement for the period	-	4,376
As at December 31	**-**	**4,376**

The movement in deferred income tax assets and liabilities, without taking into consideration the offsetting balances within the same jurisdiction, is as follows:

2017

Deferred tax assets

USD 000	Tax losses	Oil and gas assets	Provisions and others	Total
As at January 1, 2017	-	-	-	-
(Charged) / credited to the statement of comprehensive income	-	-	-	-
Classified as held for sale	-	-	-	-
As at December 31, 2017	**-**	**-**	**-**	**-**

Deferred tax liabilities

USD 000	Tangible and production assets	Exploration assets	Provisions and others	Total
As at January 1, 2017	-	-	-	-
Charged / (credited) to the statement of comprehensive income	-	-	-	-
Classified as held for sale	-	-	-	-
As at December 31, 2017	**-**	**-**	**-**	**-**

2016

Deferred tax assets

USD 000	Tax losses	Oil and gas assets	Provisions and others	Total
As at January 1, 2016	-	-	-	-
(Charged) / credited to the statement of comprehensive income	-	-	-	-
As at December 31, 2016	**-**	**-**	**-**	**-**

Deferred tax liabilities

USD 000	Tangible and production assets	Exploration assets	Provisions and others	Total
As at January 1, 2016	-	4,376	-	4,376
Charged / (credited) to the statement of comprehensive income	-	(4,376)	-	(4,376)
As at December 31, 2016	**-**	**-**	**-**	**-**

There are no recognised deferred tax assets in Group the group financial statements as of December 31, 2017.

Deferred tax assets are recognised for tax loss carry-forwards to the extent that the realization of the related tax benefits through future taxable profits is probable. The Group did not recognise deferred income tax assets of USD 14 million (2016: USD 26 million) in respect of losses that can be carried forward against future taxable income.

The Group has provisional accumulated tax losses as of year-end that may be available to offer future taxable income in the respective jurisdictions. All losses are available indefinitely except for Cyprus which, effective from the year 2012, expire after a maximum of five years since origination.

USD 000	**2017**	**2016**
Norway	46,191	88,748
UK	2,431	2,444
Cyprus	10,174	10,161
Brazil	-	-
Netherlands	3,962	8,015
Total	**62,759**	**109,368**

The decline in tax losses in Norway is primarily due to the reassessment and reduction of losses by the Norwegian Tax authorities following an assessment ruling on exchange rate translations for the period 2014-2016.

NOTE 7. BASIC AND DILUTED EARNINGS PER SHARE

Basic earnings per share

USD 000, unless otherwise stated	**2017**	**2016**
Net loss attributable to equity holders of the parent – Total	(36,589)	(62,636)
Net loss attributable to equity holders of the parent – Continuing operations	(36,312)	(61,987)
Weighted average number of shares outstanding - in thousands	42,502	38,814
Basic and diluted earnings per share – (USD) – Total	(0.86)	(1.61)
Basic and diluted earnings per share – (USD) – Continuing operations	(0.85)	(1.60)

Diluted earnings per share
When calculating the diluted earnings per share, the weighted average number of shares outstanding is normally adjusted for all dilutive effects relating to the Company's share options.

The share options had an anti-dilutive effect on earnings per share for both periods presented.

NOTE 8. LICENSES, EXPLORATION AND EVALUATION ASSETS, DEVELOPMENT ASSETS

2017

USD 000	Licences, exploration and evaluation assets	Development assets
Acquisition cost		
At January 1, 2017	25,971	-
Additions	2,782	1,380
Transfer to Licences, Exploration & Evaluation Assets *	8,246	(8,246)
Transfer to Development Assets *	(4,308)	4,308
Disposal of Dussafu	(12,053)	-
At December 31, 2017	**20,638**	**(2,558)**
Accumulated impairment		
At January 1, 2017	-	-
Impairment	7,042	(4,252)
At December 31, 2017	**7,042**	**(4,252)**
Net carrying value at December 31, 2017	**13,596**	**1,694**

2016

USD 000	Licences, exploration and evaluation assets	Development assets
Acquisition cost		
At January 1, 2016	31,033	70,195
Additions	1,293	10,979
Transfer between Development and Licences, Exploration & Evaluation and Production Assets *	31,562	(80,163)
Transfer of Pre-Commissioning Operating Costs	-	(1,011)
At December 31, 2016	**63,888**	**-**
Accumulated impairment		
At January 1, 2016	-	-
Impairment	37,917	-
At December 31, 2016	**37,917**	**-**
Net carrying value at December 31, 2016	**25,971**	**-**

* Upon commencement of commercial production from the Aje field, offshore Nigeria, historical costs capitalised since inception have been reviewed and bifurcated between costs attributable to Cenomanian Oil field and other gas discoveries on the OML 113 license. As a result, bifurcated costs has been broadly categorised between Exploration & Evaluation assets and Production Assets.

Licence area	Panoro interest	Country	Expiry of current phase
OML 113	6.502% participating interest, 12.1913% entitlement to revenue stream and 16.255% paying interest	Nigeria	June 2018
Dussafu Marin permit	8.333%	Gabon	Ten years from commencement of production *

* The third Exploration Phase under the Dussafu Marin Production Sharing Contract ("PSC") expired on May 27, 2016. The Ruche area Exclusive Exploitation Authorization ("EEA") under the Dussafu Marin PSC was granted on July 14, 2014 and is effective from that date until ten years from the date of commencement of production. If, at the end of this ten-year term commercial exploitation is still possible from the Ruche area, the EEA shall be renewed at the contractor's request for a further period of five years. Subsequent to this, the EEA may be renewed a second time for a further period of five years.

NOTE 9. TANGIBLE ASSETS

NOTE 9A. PRODUCTION ASSETS AND EQUIPMENT

USD 000	2017	2016
Acquisition cost		
At January 1	25,285	-
Additions	12,273	1,231
Transfer from Development Assets	-	48,601
At December 31	**37,558**	**49,832**
Accumulated impairment		
At January 1	-	-
Impairment charge for the year	25,828	22,413
At December 31	**25,828**	**22,413**
Accumulated depreciation		
At January 1	-	-
Depreciation charge for the year	1,828	2,134
At December 31	**1,828**	**2,134**
Net carrying value at December 31	**9,902**	**25,285**

NOTE 9B. PROPERTY, FURNITURE, FIXTURES AND EQUIPMENT

2017

USD 000	Leasehold	Furniture, Fixture and Fittings	Computer Equipment	Total
Acquisition cost				
At January 1, 2017	55	104	491	650
Additions	-	-	4	4
Disposals / write-downs	-	-	-	-
At December 31, 2017	**55**	**104**	**494**	**654**
Accumulated depreciation				
At January 1, 2017	15	46	419	480
Depreciation charge for the year	9	29	32	70
Disposals / write-downs	-	-	-	-
At December 31, 2017	**25**	**75**	**450**	**550**
Net carrying value at December 31, 2017	**30**	**29**	**44**	**103**

2016

USD 000	Leasehold	Furniture, Fixture and Fittings	Computer Equipment	Total
Acquisition cost				
At January 1, 2016	55	104	491	650
Additions	-	-	-	-
Disposals / write-downs	-	-	-	-
At December 31, 2016	**55**	**104**	**491**	**650**
Accumulated depreciation				
At January 1, 2016	5	16	363	384
Depreciation charge for the year	10	30	57	97
Disposals / write-downs	-	-	-	-
At December 31, 2016	**15**	**46**	**420**	**481**
Net carrying value at December 31, 2016	**40**	**58**	**71**	**169**

Depreciation method and rates

Category	Straight-line depreciation	Useful life
Furniture, fixtures and fittings	10–33.33%	3 – 10 years
Computer equipment	20–33.33%	3 – 5 years

NOTE 9C. OTHER NON-CURRENT ASSETS

Other non-current assets amount to USD 0.1 million. This amount relates the tenancy deposit for the UK office premises.

NOTE 9D. IMPAIRMENT IN OIL AND GAS INTERESTS

Licenses, Exploration and Evaluation Assets, Development Assets
The Group invested in Dussafu Permit, offshore Gabon and holds an 8.333% interest in the block, following the disposal of 25% of its stake in the licence during 2017 to BW Energy Gabon Pte Limited. Furthermore, during the year a final investment decision was taken on the initial development of 2 Tortue wells, coupled with a post-period end independent reserves update, which attributed higher recoverable amounts on both 1P and 2P profiles. As a result, a partial reversal of USD 4.3 million to the previously recognised Dussafu impairment was credited to the income statement. The total carrying value for Dussafu, after taking in to account the impairment reversal is USD 9.9 million as of December 31, 2017. The analysis of the carrying value has been assessed as USD 1.7 million of accumulated costs since the start of the Dussafu development project, USD 3.9 million of exploration and evaluation costs which were capitalised prior to the impairment assessment and subsequent reversal (USD 4.3million). The costs have been attributed to exploration and evaluation activities for Dussafu to reflect the planned phased developments envisaged on the license.

Key assumptions used in the VIU calculations for Dussafu
The key assumptions used in the calculation of recoverable amount for the value in use model are:
- 1P reserves as certified by NSAI;
- Production profiles achieved;
- Average USD59/bbl oil price assumption;
- Cost of development to plan;
- Cost of extraction and processing; and
- Discount rate of 13.5%.

Economically recoverable reserves and resources are based on NSAI and project plans based on Operator sourced information, supported by the evaluation work undertaken by appropriately qualified persons within the respective Joint Ventures. The impairment test is most sensitive to changes in commodity prices and discount rates.

Aje
The Group also holds investment in OML 113 license, offshore Nigeria and has a 16.255% participating interest in the field with revenue interest 12.1913%. The carrying value of USD 5.4 million as of December 31, 2017 is after taking into account impairment charge of USD 7.0 million as a result of higher than anticipated expenditures on the Aje-5 workovers and side-tracks. The OML 113 carrying value included in exploration and evaluation assets in principle represents the discovered gas reserves on the license.

Production Assets and Equipment (Aje)
The Group has investments in tangible assets with USD 9.9 million of production assets and equipment in Nigeria after taking into account impairment charge of USD 25.8 million for the year ended December 31, 2017. Production assets and equipment capitalised on the balance sheet relate entirely to Aje Cenomanian oil field within OML 113 license. Management has determined the recoverable amount as of year-end through fair value less cost of sale. This approach was adopted to reasonably measure the recoverable amount after taking into account the potential divestment structures under consideration.

The overall impairment loss was USD 32.8 million for OML 113, of which USD 7 million is in relation to exploration and evaluation assets and the remainder for production assets, was triggered by changes in the operational plan following lower than expected production, accumulated costs of Aje-5 workovers and well intervention and a decline in Cenomanian oil reserves in line with the most recent preliminary independent reserves report. To establish the recoverable amount assessed to be fair value less cost of sale for the impaired asset, Panoro made use of indicative values that could potentially result in a transaction to third parties. The data of such estimate was derived from potential transaction structures. The discounted cash flow calculation and appropriate risk factors were taken into consideration when determining the fair value less cost of disposal. The primary basis for arriving at the recoverable amount estimate was the use of unobservable market inputs which is a level 3 valuation as defined in IFRS 13.

Sensitivities to change in assumptions
In general, adverse changes in key assumptions could result in recognition of impairment charges. However, recoverable amount of OML 113 is driven from fair value less cost of sale method, which is not sensitive to oil price assumptions and will only be marginally impacted by a change in discount rates. The Group will continue to test its assets for impairment where indications are identified and may in future recognise impairment charges.

The breakdown of the net impairment expense for continuing operations is:

	2017				2016			
USD 000	Nigeria	Gabon	Corporate	Total	Nigeria	Gabon	Corporate	Total
Capitalised licenses, exploration and evaluation assets	13,142	(4,252)	-	8,890	20,770	17,147	-	37,917
Production assets and equipment	19,686	-	-	19,686	22,413	-	-	22,413
Corporate items	-	-	-	-	-	-	(162)	(162)
Reversal of historic deferred tax liability	-	-	-	-	(4,373)	-	-	(4,373)
Total charge for the year ended December 31	**32,828**	**(4,252)**	**-**	**28,576**	**38,810**	**17,147**	**(162)**	**55,795**

NOTE 10. ACCOUNTS AND OTHER RECEIVABLES

USD 000	2017	2016
Accounts receivable	-	795
Other receivables and prepayments	615	929
At December 31	**615**	**1,724**

Accounts receivables are non-interest bearing and generally on 30-120 days payment terms.

At December 31, 2017 and 2016 the allowance for impairment of receivables was USD nil.

Risk information for the receivable balances is disclosed in note (18).

NOTE 11. CASH AND BANK BALANCES

USD 000	2017	2016
Cash and bank balances	6,317	4,768
Cash and cash equivalents at December 31	**6,317**	**4,768**

As at December 31, 2017, the Company held USD 6.3 million in cash and cash equivalents (USD 4.8 million as at December 31, 2016). Following the signing of the settlement agreement on Aje, USD 1.5 million which has been held as cash collateral supporting the legal case at Aje is has been released back to the Company on completion of legal formalities post-period end.

The majority of Panoro's cash was denominated in USD and was held in a high interest account earning 0.75% interest. As at December 31, 2017 the Company held cash denominated in NOK of approximately USD 20 thousand related to the Norwegian withholding tax liability.

Overdraft facilities
The Group had no bank overdraft facilities as at December 31, 2017.

NOTE 12. DISCONTINUED OPERATIONS

Discontinued operations
Subsequent to the Board of Directors' decision to formally exit Brazil and wind-down the operations, the remaining licences in BS-3 area have been relinquished and abandonment plans have been filed with ANP. The remaining formalities are being managed in Rio de Janeiro by a third-party agent.

The Company intends to keep a low-cost corporate presence for its subsidiary Panoro Energy do Brasil Ltda, which is entitled to the contingent earn-out from GeoPark over the next year. GeoPark has confirmed through detailed earn-out calculations that no earn-out was due to the Company for 2017.

As a result, the operations of Company's subsidiaries in Brazil have been classified as discontinued operations under IFRS 5. The results of Brazilian segment for the previous year have been carved out of the operating results and presented below as discontinued operations:

USD 000	2017	2016
Oil and gas revenue	-	-
Other income	-	-
Total revenues	**-**	**-**
Production costs	-	-
Exploration related costs and operator G&A	-	-
Strategic review costs	-	-
Severance and restructuring costs	-	-
General and administration costs	(71)	(103)
EBITDA	**(71)**	**(103)**
Depreciation	-	-
Impairment	(130)	(419)
Share based payments	-	-
Gain / (loss) on sale of subsidiary	-	-
EBIT – Operating income / (loss)	**(201)**	**(522)**
Interest costs net of income	-	-
Other financial costs net of income	4	13
Net foreign exchange gain / (loss)	(6)	(5)
Income / (loss) before tax	**(203)**	**(514)**
Income tax benefit / (expense)	(74)	(135)
Net income / (loss) for the period from discontinued operations	**(277)**	**(649)**
Earnings per share (basic and diluted) for the period from discontinued operations (USD)	(0.01)	(0.02)

NOTE 13 ASSET RETIREMENT OBLIGATION

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 Aje 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 5.9% and an inflation rate of 1.5%. 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:

USD 000	2017	2016
Balance for provision at December 31,	1,925	1,856
Recognised during the year on Aje development - accretion of notional interest	114	69
At December 31	**2,039**	**1,925**

NOTE 14. SHARE CAPITAL AND RESERVES

Share capital

Amounts in USD 000 unless otherwise stated	Number of shares	Nominal Share Capital
As at January 1, 2017	42,502,196	305
Purchase of own shares	-	(6)
As at December 31, 2017	**42,502,196**	**299**

Panoro Energy was formed through the merger of Norse Energy's former Brazilian business and Pan-Petroleum on June 29, 2010. The Company is incorporated in Norway and the share capital is denominated in NOK. The share capital given above is translated to USD at the foreign exchange rate in effect at the time of each share issue. All shares are fully paid-up and carry equal voting rights

During 2017, and as part of the Company's share buyback program, the Company resolved to buy back shares, in accordance with the resolution approved by its shareholders at the Company's Annual General Meeting on 24 May 2017. Acceptances received exceeded the 1,000,000 shares limit of the Company's Offer. Following this transaction, Panoro holds a total of 1,000,000 own shares, representing 2.35% of the total issued share capital. The ongoing share buyback program may continue to be carried out in accordance with applicable laws and regulations, in open market transactions or through additional tenders, at the discretion of management based on, among other things, the Company's ongoing capital requirements and the market price of its common share.

As at December 31, 2017 and December 31, 2016, the Company had a registered share capital of NOK 2,125,109.80 divided into 42,502,196 shares with a nominal value of NOK 0.05.

The Company's twenty largest shareholders are referenced in the Parent Company Accounts, please refer to Note 9.

Shares owned by the CEO, board members and key management, directly and indirectly, at December 31, 2017:

Shareholder	Position	Number of shares	% of total
Julien Balkany (i)	Chairman of the Board of Directors	2,356,253	5.54%
Torstein Sanness	Director	35,000	0.08%
Garrett Soden (ii)	Director	10,008	0.02%
Alexandra Herger	Director	5,950	0.01%
John Hamilton	Chief Executive Officer	104,901	0.25%
Qazi Qadeer	Chief Financial Officer	41,850	0.10%
Richard Morton	Technical Director	91,214	0.21%

(i) Mr. Balkany has beneficial interest in Nanes Balkany Partners I LP which owns 600,106 shares in the Company, and Balkany Investments LLC which owns 1,725,338 shares in the Company. In addition, Mr. Balkany directly holds 30,809 shares in the Company.

(ii) Mr. Soden holds directly or indirectly 10,008 shares in the Company.

Reserves

Share premium

Share premium reserve represents excess of subscription value of the shares over the nominal amount.

Other reserves

Other reserves represent items arising on consolidation of PEdB as comparatives and execution of merger.

Additional paid-in capital

Additional paid-in capital represents reserves created under the continuity principle on demerger. Share-based payments credit is also recorded under this reserve and so is the credit from reduction of share capital by reducing the par value of shares.

Currency translation reserve

The translation reserve comprises all foreign exchange differences arising from the translation of the financial statements of foreign operations.

NOTE 15. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

USD 000	**2017**	**2016**
Accounts payable	141	254
Accruals and other payables	6,669	2,033
Long-term liabilities	9,089	-
At December 31	**15,899**	**2,287**

Long-term liabilities

The Company has in place a non-recourse loan from BW Energy in relation to the funding of the Dussafu development. As of December 31, 2017, Panoro's drawdown on the non-recourse loan was USD 2.2 million. The non-recourse loan is repayable through Panoro's allocation of the cost oil in accordance with the Dussafu PSC, after paying for the proportionate field operating expenses. The repayment will start at First Oil on Dussafu. During the repayment phase, Panoro will still be entitled to its share of profit oil from the Dussafu operations.

Since the settlement of the Aje dispute, the Company has performed a review of historical costs incurred and recognised the liabilities associated with such expenditures in the balance sheet. The proportionate joint venture liabilities resulting from the workover and side-tracks at Aje-5 have been higher than anticipated and as such have resulted in proportional liabilities of USD 6.1 million as of December 31, 2017. Such liabilities are current in nature and are expected to be repaid in full by the end of financial year 2018.

In addition to these, USD 6.8 million is classified as long-term liabilities which as per the terms agreed between OML 113 Joint Venture partners, certain transitional arrangements were introduced whereby unpaid cash calls will not be immediately payable. During the transition period, any excess funds from Panoro's entitlement of crude liftings after paying for its share of operating expenditure shall be used to repay unpaid cash calls. In addition to this, commercial arrangements agreed as part of the interim settlement measures are expected to have the effect of increasing Panoro's existing revenue interest for the remainder of 2018. It is anticipated that operating costs for OML 113 will be funded in entirety from the sale of our share of Aje crude during 2018.

NOTE 16. RESTRICTED STOCK UNITS SCHEME

Restricted Stock Unit scheme ("RSUs")

At the annual general meeting held on May 27, 2015, a new employee incentive scheme was approved whereby the Company may issue restricted stock units ("RSUs") to executive employees. Awards under the new scheme will normally be considered one time per year and grant of share based incentives will in value (calculated at the time of grant) be capped to 100% of the annual base salary for the CEO and 50% of the annual base salary for other members of the executive management. One RSU will entitle the holder to receive one share of capital stock of the Company against payment in cash of the par value for the share. The total number of RSUs available for grant under the RSU program during the period from the 2015 annual general meeting and up to the annual general meeting in 2018 shall not exceed 5% of the number of shares outstanding as per the date of the 2015 annual general meeting (at which point in time the total number of shares was 234,545,786). Grant of RSUs will be subject to a set of performance metrics with threshold and factors reviewed annually by the Board of Directors. Such metrics will be set as objectives based on sustained performance results including mostly share price increases and achievement of specific financial performance measures related to a group of oil and gas exploration and production peers that has been defined and adopted by a committee established by the Board.

In June 2017, 420,000 Restricted Share Units (RSU) were awarded under the Company's RSU scheme to key employees of the Company under the long term incentive compensation plan approved by the shareholders. One RSU entitles the holder to receive one share of capital stock of the Company against payment in cash of the par value of the share. The par value is currently NOK 0.05 per share. Vesting of the RSUs is time based. The standard vesting period is 3 years, where 1/3 of the RSUs vest after one year, 1/3 vest after 2 years and the final 1/3 vest after 3 years from grant. RSUs vest automatically at the respective vesting dates and the holder will be issued the applicable number of shares as soon as possible thereafter.

During the year ended December 31, 2017, 420,000 RSUs had been granted (200,000 granted as at December 31, 2016). All of the 420,000 RSUs were outstanding as of December 31, 2017 and the awards related to permanent employees of the Company. No RSUs were vested, terminated, exercised or expired during the year. The weighted average exercise price of the RSUs granted during the year was NOK 0.05 per unit.

NOTE 17. FINANCIAL INSTRUMENTS

Fair Value

Set out below is a comparison by category of carrying amounts and fair values of all the Group's financial instruments that are carried in the financial statements:

		Carrying amount		Fair value		
USD 000	**Financial instrument classification**	**2017**	**2016**	**2017**	**2016**	**Fair value hierarchy**
Financial assets						
Cash and bank balances	Fair value through the P&L	6,317	4,768	6,317	4,768	Level 3
Accounts receivable	Loans and receivables	-	795	-	795	Level 3
Financial liabilities						
Non-recourse loan	Other financial liabilities	2,197	-	2,197	-	Level 3
Accounts payable and accrued liabilities	Other financial liabilities	6,737	2,469	6,737	2,469	Level 3

Determination of fair value

The carrying amount of cash and bank balances is equal to fair value since no financial instruments were entered into during 2017. Similarly, the carrying amount of accounts receivables and accounts payables is equal to fair value since they are entered into on "normal" terms and conditions.

NOTE 18. FINANCIAL RISK MANAGEMENT

The Group's principal financial liabilities comprise of accounts payables. 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 December 31, 2017 and December 31, 2016, 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 interest rate risk, foreign currency risk, liquidity risk and credit 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 show the impact on profit or loss and shareholders' equity, where applicable. Financial instruments affected by market risk include, accounts receivables, accounts payable and accrued liabilities.

The sensitivity has been prepared for periods ending December 31, 2017 and 2016 using the amounts of debt and other financial assets and liabilities held as at those reporting dates.

Interest rate risk

The Group's exposure to the risk of changes in market interest rates relates primarily to the Group's cash balances.

The following table demonstrates the sensitivity to a reasonably possible change in interest rates, with all other variables held constant, of the Group's profit before tax through the impact on cash and cash equivalents.

USD 000	2017		2016	
	+100bps	-100bps	+100bps	-100bps
Cash	46	(46)	26	(26)
Net effect	**46**	**(46)**	**26**	**(26)**

Foreign currency risk
The Company operates internationally and is exposed to risk arising from various currency exposures, primarily with respect to the Norwegian Kroner (NOK), the Pound Sterling (GBP) and the Brazilian Real (BRL). From a financial statements perspective, the subsidiary in Brazil has a BRL functional currency and is exposed to fluctuations for presentation purposes in these financial statements. The volatility in BRL has resulted in a translation loss of USD 3 thousand as of December 31, 2017 (2016: USD 10 thousand loss).

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 income statement and balance sheet 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.

The Group evaluates on a continuous basis to use cross currency swaps if deemed appropriate by management in order to hedge the forward foreign currency risk. The group used no derivatives/swaps during 2017 or 2016.

A 20% strengthening or weakening of the USD against the following currencies at December 31, 2017 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.

USD 000	2017		2016	
USD vs NOK	**+ 20%**	**-20%**	**+ 20%**	**-20%**
Cash	(27)	27	(20)	20
Receivables	-	-	(53)	53
Payables	19	(19)	138	(138)
Net effect	**(8)**	**8**	**64**	**(64)**
USD vs GBP	**+ 20%**	**-20%**	**+ 20%**	**-20%**
Cash	(63)	63	(23)	23
Receivables	(5)	5	(5)	5
Payables	46	(46)	54	(54)
Net effect	**(22)**	**22**	**26**	**(26)**
USD vs BRL	**+ 20%**	**-20%**	**+ 20%**	**-20%**
Cash	(25)	25	(1)	1
Receivables	(1)	1	(24)	24
Payables	61	(61)	70	(70)
Net effect	**35**	**(35)**	**46**	**(46)**

Liquidity risk
Liquidity risk is the risk that the Group will not be able to meet its obligations as they fall due. Prudent liquidity risk management includes maintaining sufficient cash and marketable securities, the availability of funding from an adequate amount of committed credit facilities and the ability to close out market positions.

The table below summarises the maturity profile of the Group's financial liabilities at December 31, 2017 based on contractual undiscounted payments.

2017

USD 000	On demand	Less than 1 year	1 to 2 years	2 to 5 years	>5 years	Total
Accounts payable and accrued liabilities	-	6,810	9,089	-	-	15,899
Total	**-**	**6,810**	**9,089**	**-**	**-**	**15,899**

2016

USD 000	On demand	Less than 1 year	1 to 2 years	2 to 5 years	>5 years	Total
Accounts payable and accrued liabilities	-	2,381	88	-	-	2,469
Total	**-**	**2,381**	**88**	**-**	**-**	**2,469**

The Company had USD 6.3 million in cash and bank balances as of December 31, 2017 not including USD 1.5 million cash was set aside as security of costs in relation to the dispute at Aje. Following the completion of legal formalities, funds were released back to the Company with interest post-period-end. The Company expects it is fully funded through the development of Phase 1 at Dussafu, from cash balances, cash flow from operations, and the non-recourse loan from BWEG. 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, and the issuance of shares. As a result, the financial statement has been prepared under the assumption of going concern and realization of assets and settlement of debt in normal operations.

Credit risk
The Group is exposed to credit risk that arises from cash and cash equivalents, derivative financial instruments and deposits with banks and financial institutions, as well as credit exposures to customers, including outstanding receivables and committed transactions.

For banks and financial institutions, only independently rated parties with a minimum rating of "A" are accepted. Any change of financial institutions (except minor issues) are approved by the Group CFO. The Company may engage with counterparties of a lower rating by taking lower exposures in such counterparties to mitigate the risks.

If the Group's customers are independently rated, these ratings are used. Otherwise, if there is no independent rating, risk control in the operating units assesses the credit quality of the customer, taking into account its financial position, past experience and other factors. The utilization of credit limits is regularly monitored and kept within approved budgets.

Capital Management
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 are fully funded for its committed 2018 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 Company has no 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 that in the forthcoming year.

NOTE 19. GUARANTEES AND PLEDGES

Brazil
The Company has provided a performance guarantee to the ANP, in terms of which the Company is liable for the commitments of Coral and Cavalo Marinho licenses in accordance with the given concessions of the licenses. The guarantee is unlimited.

UK
Under section 479A of the UK Companies Act 2006; two of the Company's indirect subsidiaries Panoro Energy Limited (Registration number: 6386242) and African Energy Equity Resources Limited (Registration number: 5724928) have availed exemption for audit of their statutory financial statements pursuant to guarantees issued by the Company to indemnify the subsidiaries of any losses towards third parties that may arise in the financial year ended December 31, 2017 in such Companies. The Company can make an annual election to support such guarantee for each financial year.

Gabon
The Company has a guarantee issued to the State of Gabon to fulfil all obligations under the Dussafu Production Sharing Contract. There is no potential claim against these performance guarantee and all license obligations are already accounted for in the balance sheet.

NOTE 20. OTHER COMMITMENTS AND CONTINGENT LIABILITIES

Leasing arrangements
Operating leases relate to leases of office space with lease terms between 1 to 10 years.

Non-cancellable operating lease commitments

USD 000	**2017**	**2016**
Not later than 1 year	267	243
Later than 1 year and not later than 5 years	401	608
Later than 5 years	-	-
At December 31	**668**	**851**

The above table sets out the Group's future commitments of lease payments based on a standard rental period with minimum payments (i.e. fixed rental costs excluding additional lease payments calculated based on revenue) under (1) 1 year, (2) 1-5 years, (3) after 5 years, as of December 31, 2017. The lease rentals primarily relate to office premises in London which has ten year lease with a break clause in year five. At the end of the initial five year period the lease terms are subject to a mutual review and therefore only minimum payments up to such period are included in the table.

The office premises in London are sub-let from Elan Property B.V. and cover an area of approximately 2,196 square feet. The office space is purely used for office staff and related activities and contains normal office furniture, IT equipment and supplies.

The Group is also contracted through the OML 113 Joint Venture in a ten year bare-boat charter of the FPSO vessel Front Puffin. The Group's share of lease rentals in the initial three year contract period started from July 2016. The minimum rentals for the financial year ending December 31, 2018 is USD 1.7 million and USD 0.9 million up to the completion of the third anniversary from the commencement of commercial production in July 2019. After the initial three years, the lease is cancellable without penalties. The initial charter period is for an initial period of five years with annual subsequent renewals up to year 10. The applicable estimated rentals are subject to oil price thresholds in accordance with the Bare Boat charter agreement whereby the rentals may be higher for any given period from year to year should the oil price exceed certain pre-defined thresholds in any average monthly billing cycle. The estimated rentals disclosed on this note are based on Group's net paying interest of 16.255% in Aje Cenomanian oil development.

Uncertainties surrounding abandonment liabilities
In Brazil, termination agreements for the surrender of Coral and Cavalho Marinho licences have been signed between the JV partners and Brazilian Regulator ANP. The next steps involve various regulatory clearances before dissolution of JV operations. The Company's formal exit from its historical Brazilian business is still ongoing with slow progress towards the approval of abandonment by the Brazilian regulators. Management is working actively with the operator Petrobras to bring matters to a close and to ensure that the ongoing costs are kept to a minimum. However, the timing and eventual costs of such conclusion is uncertain at this stage.

OML 113 – Aje, Nigeria

On November 2, 2017, Panoro announced that its subsidiary Pan Petroleum Aje Limited ("PPAL") had entered into a binding agreement with the other OML 113 joint-venture partners. The agreement in conjunction with other initiatives addresses a number of operational and financial issues. Under the terms of the agreement, certain transitional arrangements were introduced whereby unpaid cash calls will not be immediately payable. Such unpaid cash calls are included in the long-term payable balance as of the end of the quarter. During the transition period, any excess funds from Panoro's entitlement of crude liftings shall be used to pay operational costs incurred in the JV, any remaining liabilities and unpaid cash calls. In addition to this, commercial arrangements agreed as part of the settlement measures are expected to have the effect of increasing PPAL's existing revenue interest until approximately the end of 2018.

On January 2, 2018, post period end, Panoro announced that PPAL had entered into a definitive and binding settlement agreement (the "Agreement") with the other OML 113 joint-venture partners. The Agreement resolved and settled the dispute between the OML 113 joint-venture partners in relation to drilling of new development wells.

The highlights of the Agreement included:

- All OML 113 joint-venture partners have agreed to halt and withdraw all litigation and arbitration proceedings among the partners;
- PPAL would not pay for any Aje-6 costs that have been incurred by the JV, until such time as the equipment and parts are to be used in any potential future well operations;
- Substantial court costs already awarded to PPAL to be retained and any remaining balances credited in favour of PPAL; and
- PPAL's USD 1.5 million cash security deposit held with UK Courts Funds Office would be released and returned to it. PPAL completed the formalities post-period end and funds have been returned.

Panoro remains committed to explore all options to maximise value at Aje, including, but not limited to, a partial or full divestment of its participation in OML 113.

NOTE 21. RELATED PARTIES TRANSACTIONS

The only related party transactions during the year relate to directors' remuneration which is disclosed in note 4d.

NOTE 22. SUBSIDIARIES

Details of the Group's subsidiaries as of December 31, 2017, are as follows:

Subsidiary	Place of incorporation and ownership	Ownership interest and voting power
Panoro Energy do Brasil Ltda	Brazil	100%
Panoro Energy Limited	UK	100%
African Energy Equity Resources Limited	UK	100%
Pan-Petroleum (Holding) Cyprus Limited	Cyprus	100%
Pan-Petroleum Holding B.V.	Netherlands	100%
Pan-Petroleum Gabon B.V.	Netherlands	100%
Pan-Petroleum Gabon Holding B.V.	Netherlands	100%
Pan-Petroleum Nigeria Holding B.V.	Netherlands	100%
Pan-Petroleum Services Holding B.V.	Netherlands	100%
Pan-Petroleum AJE Limited	Nigeria	100%
Energy Equity Resources AJE Limited	Nigeria	100%
Energy Equity Resources Oil and Gas Limited	Nigeria	100%
Syntroleum Nigeria Limited	Nigeria	100%
PPN Services Limited	Nigeria	100%
Energy Equity Resources (Cayman Islands) Limited	Cayman Islands	100%
Energy Equity Resources (Nominees) Limited	Cayman Islands	100%
Panoro Energy Gabon Production SA	Gabon	100%

NOTE 23. EVENTS SUBSEQUENT TO REPORTING DATE

On January 2, 2018, post period end, Panoro announced that PPAL had entered into a definitive and binding settlement agreement (the "Agreement") with the other OML 113 joint-venture partners. The Agreement resolved and settled the dispute between the OML 113 joint-venture partners in relation to drilling of new development wells.

The highlights of the Agreement included:

- All OML 113 joint-venture partners have agreed to halt and withdraw all litigation and arbitration proceedings among the partners;
- PPAL would not pay for any Aje-6 costs that have been incurred by the JV, until such time as the equipment and parts are to be used in any potential future well operations;
- Substantial court costs already awarded to PPAL to be retained and any remaining balances credited in favour of PPAL; and
- PPAL's USD 1.5 million cash security deposit held with UK Courts Funds Office would be released and returned to it. PPAL completed the formalities post-period end and funds have been returned.

NOTE 24. RESERVES (UNAUDITED)

The Group has adopted a policy of regional reserve reporting using external third party companies to audit its work and certify reserves and resources according to the guidelines established by the Oslo Stock Exchange ("OSE"). 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. Panoro uses the services of Gaffney, Cline & Associates ("GCA") and AGR TRACS International Limited 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 (MMBOE)	2P reserves (MMBOE)	3P reserves (MMBOE)
Aje (OML 113)	12.1	20.0	30.9
Tortue (Dussafu)	1.1	1.6	1.8
Panoro Total	**13.2**	**21.6**	**32.7**

During 2017, the Group had the following reserve development:

	2P reserves (MMBOE)
Balance (previous ASR) as of December 31, 2016	3.1
Production 2017	(0.1)
Revision of previous estimates, as per new ASR *	(2.6)
New developments since previous ASR *	21.2
Balance (current ASR) as of December 31, 2017	**21.6**

* New ASR data received in April 2018.

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.

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PANORO ENERGY ASA
PARENT COMPANY INCOME STATEMENT

For the year ended December 31, 2017

USD 000	Note	2017	2016
Operating income			
Operating revenues			
Total operating income			
Operating expenses			
General and administrative expense		(1,751)	(1,249)
Intercompany recharges	8	-	-
Impairment of investments in subsidiary	2, 6	(335)	(38,873)
Loss on disposal of tangible assets		-	-
Impairment of loan to subsidiaries	7, 8	(32,885)	(28,311)
Depreciation		-	-
Total operating expenses		**(34,971)**	**(68,433)**
Operating result	**2**	**(34,971)**	**(68,433)**
Financial income	3	9,356	10,122
Interest and other finance expense	3	(79)	(95)
Currency gain / (loss)		16	21
Result before income taxes		**(25,678)**	**(58,385)**
Income tax	5	-	-
Result for the year		**(25,678)**	**(58,385)**
Earnings per share (basic and diluted) – USD	4	(0.60)	(1.50)

The annexed notes form an integral part of these financial statements.

PANORO ENERGY ASA
PARENT COMPANY BALANCE SHEET

As at December 31, 2017

USD 000	Note	2017	2016
ASSETS			
Non-current assets			
Investment in subsidiaries	6	-	-
Intercompany receivables	7	-	-
Total non-current assets		**-**	**-**
Current assets			
Loans to subsidiaries	8	29,076	57,148
Other current assets		-	277
Cash and cash equivalent		4,705	3,926
Restricted cash		1,500	520
Total current assets		**35,281**	**61,871**
TOTAL ASSETS		**35,281**	**61,871**
EQUITY AND LIABILITIES			
EQUITY			
Paid-in capital			
Share capital	9	299	305
Share premium reserve	9	297,490	297,503
Treasury Shares		(503)	-
Additional paid-in capital	9	122,055	122,054
Total paid-in capital		**419,341**	**419,863**
Other equity			
Other reserves	9	(390,079)	(364,402)
Total other equity		**(390,079)**	**(364,402)**
TOTAL EQUITY		**29,262**	**55,461**
LIABILITIES			
Current liabilities			
Accounts payable		13	18
Intercompany payables	8	5,744	5,722
Other current liabilities	10	262	670
Total current liabilities		**6,019**	**6,410**
TOTAL LIABILITIES		**6,019**	**6,410**
TOTAL EQUITY AND LIABILITIES		**35,281**	**61,871**

The annexed notes form an integral part of these financial statements.

PANORO ENERGY ASA
PARENT COMPANY STATEMENT OF CASH FLOW

For the year ended December 31, 2017

USD 000	Note	2017	2016
CASH FLOW FROM OPERATING ACTIVITIES			
Net income / (loss) for the year		(25,678)	(58,385)
Adjusted for:			
Impairment of investment in subsidiary	6	335	38,528
Provision for Doubtful Receivables	7, 8	32,885	28,311
Financial Income	3	(9,356)	(10,122)
Financial Expenses	3	79	95
Foreign exchange gains / losses		(16)	(21)
(Increase) / decrease in trade and other receivables		277	(268)
Increase / (decrease) in trade and other payables		(413)	523
(Increase) / decrease in intercompany receivables		-	-
Increase / (decrease) in intercompany payables		22	5,673
Net cash flows from operating activities		**(1,865)**	**4,334**
CASH FLOWS FROM INVESTING ACTIVITIES			
Net proceeds from loans to subsidiaries		12,737	-
Loans to subsidiaries		(8,573)	(14,527)
Net cash flows from investing activities		**4,164**	**(14,527)**
CASH FLOWS FROM FINANCING ACTIVITIES			
Own shares buyback		(509)	-
Net proceeds from Equity Private Placement		-	8,755
Interests paid		(79)	(95)
Interests received		32	52
Movement in restricted cash		(980)	(520)
Net cash flows from financing activities		**(1,536)**	**8,192**
Effect of foreign currency translation adjustment on cash balances		16	21
Net increase in cash and cash equivalents		**779**	**(1,980)**
Cash and cash equivalents at the beginning of the year		3,926	5,906
Cash and cash equivalents at the end of financial year		**4,705**	**3,926**

The annexed notes form an integral part of these financial statements.

NOTE 1. ACCOUNTING PRINCIPLES

The annual accounts for the parent company Panoro Energy ASA (the "Company") are prepared in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway. The consolidated financial statements have been prepared under International Financial Reporting Standards ("IFRS") as adopted by the European Union ("EU") and are presented separately from the parent company.

The accounting policies under IFRS are described in note 2 of the consolidated financial statements. The accounting principles applied under NGAAP are in conformity with IFRS unless otherwise stated in the notes below.

The Company's annual financial statements are presented in US Dollars (USD) and rounded to the nearest thousand, unless otherwise stated. USD is the currency used for accounting purposes and is the functional currency. Shares in subsidiaries and other shares are recorded in Panoro Energy ASA's accounts using the cost method of accounting and reduced by impairment, if any.

NOTE 2. GENERAL AND ADMINISTRATIVE EXPENSES

Operating result
Operating result is stated after charging / (crediting):

USD 000	**2017**	**2016**
Employee benefits expense (note 2.1)	14	4
Impairment of investment in subsidiary (note 7)	335	38,873
Impairment of Intercompany Loans	32,885	28,311
Operating lease payments	-	-

2.1 Employee benefits expense

a) Salaries
The Company had zero employees at December 31, 2017 and at December 31, 2016. As such, there are no wages and salaries included in general and administrative expenses.

Employee related expenses:

USD 000	**2017**	**2016**
Salaries	-	-
Employer's contribution	14	4
Pension costs	-	-
Other compensation including severance provision	-	-
Total	**14**	**4**

For details relating to remuneration of CEO and CFO, refer to note 4c in the consolidated financial statements.

b) Directors' remuneration
Please refer to note 4d of the Group financial statements for details on how directors' remuneration is determined.

Remuneration to members of the Board of Directors is summarized below:

USD 000	2017	2016
Julien Balkany	68	66
Alexandra Herger	39	38
Garrett Soden	39	38
Torstein Sanness	39	38
Hilde Adland (i)	39	28
Total	**224**	**208**

(i) Pursuant to an Extraordinary General Meeting held on March 2, 2016, Hilde Ådland was elected to the Board of Directors with an effective date of April 1, 2016.

No loans have been given to, or guarantees given on the behalf of, any members of the Management Group, the Board or other elected corporate bodies.

No pension benefits were received by the Directors during 2017 and 2016.

There are no severance payment arrangements in place for the Directors.

c) Pensions
The Company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("Lov om obligatorisk tjenestepensjon"). The Company contributes to an external defined contribution scheme and therefore no pension liability is recognized in the balance sheet.

d) Auditor
Fees (excluding VAT) to the Company's auditors are included in general and administrative expenses and are shown below.

USD 000	2017	2016
Ernst & Young		
Statutory audit	43	45
Tax services	-	-
Total	**43**	**45**

e) Share based payment and new Restricted Share Units scheme
New Restricted Stock Unit scheme ("RSUs")
At the annual general meeting held on May 27, 2015, a new employee incentive scheme was approved where-under the Company may issue restricted stock units ("RSUs") to executive employees. Awards under the new scheme will normally be considered one time per year and grant of share based incentives will in value (calculated at the time of grant) be capped to 100% of the annual base salary for the CEO and 50% of the annual base salary for other members of the executive management. One RSU will entitle the holder to receive one share of capital stock of the Company against payment in cash of the par value for the share. The total number of RSUs available for grant under the RSU program during the period from the 2015 annual general meeting and up to the annual general meeting in 2018 shall not exceed 5% of the number of shares outstanding as per the date of the 2015 annual general meeting (at which point in time the total number of shares was 234,545,786). Grant of RSUs will be subject to a set of performance metrics with threshold and factors reviewed annually by the Board of Directors. Such metrics will be set as objectives based on sustained performance results including mostly share price increases and achievement of specific financial performance measures related to a group of oil and gas exploration and production peers that has been defined and adopted by a committee established by the Board. Vesting of the RSUs is time based. The standard vesting period is three years, where 1/3 of the RSUs vest after one year, 1/3 vest after two years, and the final 1/3 vest after three years after grant, unless the Board decides otherwise for specific grants. RSUs vest automatically at the respective vesting dates and the holder will be issued the applicable number of shares as soon as possible thereafter.

In June 2017, 420,000 Restricted Share Units (RSU) were awarded under the Company's RSU scheme to key employees of the Company under the long term incentive compensation plan approved by the shareholders. One RSU entitles the holder to receive one share of capital stock of the Company against payment in cash of the par value of the share. The par value is currently NOK 0.05 per share. Vesting of the RSUs is time based. The standard vesting period is 3 years, where 1/3 of the RSUs vest after one year, 1/3 vest after 2 years and the final 1/3 vest after 3 years from grant. RSUs vest automatically at the respective vesting dates and the holder will be issued the applicable number of shares as soon as possible thereafter.

During the year ended December 31, 2017, 420,000 RSUs had been granted (200,000 granted as at December 31, 2016). All of the 420,000 RSUs were outstanding as of December 31, 2017 and the awards related to permanent employees of the

Company. No RSUs were vested, terminated, exercised or expired during the year. The weighted average exercise price of the RSUs granted during the year was NOK 0.05 per unit.

NOTE 3. FINANCIAL ITEMS

The financial expense breakdown is below:

USD 000	**2017**	**2016**
Interest income from subsidiaries	9,324	10,070
Other interest income	32	52
Total	**9,356**	**10,122**

Interest income from subsidiaries represents an interest on the intercompany loans. Refer to Note 8 for further information on these balances.

The financial expense breakdown is below:

USD 000	**2017**	**2016**
Interest expense on bond loans	-	-
Amortisation of debt issue costs	-	-
Early redemption penalty on bond loans	-	-
Bank and other financial charges	79	95
Total	**79**	**95**

NOTE 4. EARNINGS PER SHARE

Basic earnings per share

USD 000 unless otherwise stated	**2017**	**2016**
Net result for the period	(25,678)	(58,385)
Weighted average number of shares outstanding - in thousands	42,502	38,814
Basic and diluted earnings per share – (USD)	(0.60)	(1.50)

Diluted earnings per share
When calculating the diluted earnings per share, the weighted average number of shares outstanding is normally adjusted for all dilutive effects relating to the Company's options.

NOTE 5. INCOME TAX

USD 000	**2017**	**2016**
Tax payable	-	-
Change in deferred tax	-	-
Income tax expense	**-**	**-**

Specification of the basis for tax payable:

USD 000	**2017**	**2016**
Result before income tax	**(25,678)**	**(58,385)**
Effect of permanent differences	33,168	67,472
Tax losses not utilised / (utilised)	(7,490)	(9,087)
Basis for tax payable	**-**	**-**

Specification of deferred tax:

USD 000	2017	2016
Losses carried forward	46,191	88,748
Taxable temporary differences	-	-
Basis for tax payable	**46,191**	**88,748**
Calculated deferred tax asset (24%)	11,086	22,187
Unrecognised deferred tax asset	(11,086)	(22,187)
Deferred tax recognised on balance sheet	-	-

The tax losses carried forward are available indefinitely to offset against future taxable profits. The tax losses per return for the year ended December 31, 2016 was NOK 471.0 million (USD 57.4 million at 2017 closing exchange rate). The 2017 income for tax purposes has been provisionally calculated at NOK 62.3 million (approximately USD 7.6 million). The decline in tax losses in Norway is primarily due to the reassessment and reduction of losses by the Norwegian Tax authorities following an assessment ruling on exchange rate translations for the period 2014-2016.

The deferred tax asset is not recognized on the balance sheet due to uncertainty of income.

NOTE 6. INVESTMENT IN SUBSIDIARIES

Investments in subsidiaries are carried at the lower of cost and fair market value. As of December 31, 2017 USD 3 (2016: USD 1) the holdings in subsidiaries consist of the following:

USD 000	Headquarters	Ownership interest and voting rights
Panoro Energy do Brasil Ltda (PEdB)	Rio de Janeiro, Brazil	100%
Pan-Petroleum (Holding) Cyprus Ltd (PPHCL)	Limassol, Cyprus	100%
Pan-Petroleum Gabon Holding B.V. (PPGHBV)	Amsterdam, Netherlands	100%
Pan-Petroleum Nigeria Holding B.V. (PPNHBV)	Amsterdam, Netherlands	100%
Pan-Petroleum Services Holding B.V. (PPSHBV)	Amsterdam, Netherlands	100%

	PEdB	PPHCL	PPGHBV	PPNHBV	PPSHBV	Total
Investment at cost						
At January 1, 2017	94,967	129,106	-	-	-	224,073
Investments during the year	335	-	-	-	-	335
At December 31, 2017	95,302	129,106	-	-	-	224,408
Provision for impairment						
At January 1, 2017	(94,967)	(129,106)	-	-	-	(224,073)
Charge for the year (note 6.1)	(335)	-	-	-	-	(335)
At December 31, 2017	(95,302)	(129,106)	-	-	-	(224,408)
Total investment in subsidiaries at December 31, 2017	-	-	-	-	-	-
Total investment in subsidiaries at December 31, 2016	-	-	-	-	-	-

Note 6.1 Impairment represents loss in value of Company's investment in shares of Panoro Energy do Brasil Ltda of USD 335 thousand (2016: USD 345 thousand). The impairment has been determined by comparing estimated recoverable value of the underlying investment with the carrying amount.

Note 6.2 During 2017, and as part of the Group's overall reorganisation, the Company acquired all outstanding shares in Pan-Petroleum Nigeria Holding B.V. (PPNHBV) and Pan-Petroleum Services Holding B.V. (PPSHBV) from their indirectly wholly owned subsidiary, Pan-Petroleum Holding B.V. PPNHBV and PPSHBV are only holding companies with no significant assets or liabilities and the only item of value in these companies is their investment in shares in Pan-Petroleum Aje Limited which holds 6.502% equity interest in the Oil Mining Licence, OML 113, offshore Nigeria which contains the Aje Cenomanian oil producing field. Since the Company has a significant investment in the form of a loan which is not likely to be fully recoverable, and considering the net liability position of PPNHBV and PPSHBV, a consideration of EUR 1 was paid for their entire share capital.

NOTE 7. PROVISION FOR DOUBTFUL RECEIVABLES

Provision for doubtful receivables is USD 32.9 million (2016: USD 28.3 million). The provision is represented by the following:

- Uncollectible loan principal in part of USD 32.2 million (2016: USD nil) reflecting the further impairment of the Aje Asset during 2017. Subsequently, the Company's loan to its subsidiary, Pan-Petroleum Aje Limited is now reflective of the underlying book value of the Aje Asset.
- Uncollectible loan principal in part of USD 0.7 million (2016: USD 28.3 million) reflective of the underlying book value of the Dussafu Asset.

NOTE 8. RELATED PARTY TRANSACTIONS AND BALANCES

The Company's loan to the Dutch subsidiary Pan-Petroleum Gabon B.V was classified as current and amounted to USD 9.9 million as at December 31, 2017 (2016: USD 15.2 million). This loan carries an interest rate of 10% and is repayable on demand.

The Company's loan to the Nigerian subsidiary Pan-Petroleum Aje Limited was classified as current and amounted to USD 15.3 million as at December 31, 2017 (2016: USD 38.4 million). This loan carries an interest rate of 10% and is repayable on demand.

Payable balances on account of intercompany recharges was USD 4.4 million (2016: USD 4.1 million) to Company's indirect subsidiary Panoro Energy Limited, which provides technical services and Pan-Petroleum (Holding) Cyprus Limited was USD 1.4 million (2016: USD 1.6 million). These balances do not carry an interest rate and have no maturity date.

NOTE 9. SHAREHOLDERS' EQUITY AND SHAREHOLDER INFORMATION

Nominal share capital in the Company at December 31, 2017 and as at December 31, 2016 amounted to NOK 2,125,110 (USD 304,838) consisting of 42,502,196 shares at a par value of NOK 0.05. All shares in issue are fully paid-up and carry equal voting rights.

The table below shows the changes in equity in the Company during 2017 and 2016:

USD 000	Share capital	Share premium reserve	Treasury shares	Additional paid-in capital	Other equity	Total
At January 1, 2016	193	288,858	-	122,055	(306,015)	105,091
Loss for the year	-	-	-	-	(58,385)	(58,385)
Share Issue for Cash	112	9,295	-	-	-	9,407
Transaction Costs on Share Issue	-	(650)	-	-	-	(650)
At December 31, 2016	**305**	**297,503**	**-**	**122,055**	**(364,402)**	**55,461**
Loss for the year	-	-	-	-	(25,678)	(25,678)
Purchase Own Shares	(6)	-	(503)	-	-	(509)
Transaction Costs on Share Buyback	-	(13)		-	-	(13)
At December 31, 2017	**299**	**297,490**	**(503)**	**122,055**	**(390,080)**	**29,262**

Ownership structure

The Company had 3,729 shareholders per December 31, 2017 (2016: 4,371). The twenty largest shareholders were:

No.	Shareholder	Number of shares	Holding in %
1	STOREBRAND VEKST VERDIPAPIRFOND	2,670,082	6.28%
2	J.P. MORGAN SECURITIES LLC	2,325,444	5.47%
3	KLP AKSJENORGE	2,049,269	4.82%
4	F2 FUNDS AS	1,940,412	4.56%
5	KOMMUNAL LANDSPENSJONSKASSE	1,847,585	4.35%
6	DANSKE INVEST NORGE VEKST	1,446,479	3.40%
7	PANORO ENERGY ASA	1,000,000	2.35%
8	NORDNET BANK AB	860,060	2.02%
9	NORDNET LIVSFORSIKRING AS	760,537	1.79%
10	STORHAUGEN INVEST AS	600,000	1.41%
11	RAVI INVESTERING AS	500,000	1.18%
12	TIGERSTADEN AS	469,854	1.11%
13	HAUGESUND PSYKIATRISKE SENTER AS	450,184	1.06%
14	PREDATOR CAPITAL MANAGEMENT AS	445,000	1.05%
15	KAMPEN INVEST AS	420,550	0.99%
16	MEGARON AS	400,000	0.94%
17	LARSEN OIL & GAS AS	394,189	0.93%
18	BALLISTA AS	393,438	0.93%
19	VESLIK AS	340,448	0.80%
20	STEINAR SVOREN	326,600	0.77%
	Top 20 shareholders	**19,640,131**	**46.21%**
	Other shareholders	22,862,065	53.79%
	Total shares	**42,502,196**	**100.00%**

Shares owned by the CEO, board members and key management, directly and indirectly, at December 31, 2017:

Shareholder	Position	Number of shares	% of total
Julien Balkany (i)	Chairman of the Board of Directors	2,356,253	5.54%
Torstein Sanness	Director	35,000	0.08%
Garrett Soden (ii)	Director	10,008	0.02%
Alexandra Herger	Director	5,950	0.01%
John Hamilton	Chief Executive Officer	104,901	0.25%
Qazi Qadeer	Chief Financial Officer	41,850	0.10%
Richard Morton	Technical Director	91,214	0.21%

(i) Mr. Balkany has beneficial interest in Nanes Balkany Partners I LP which owns 600,106 shares in the Company, and Balkany Investments LLC which owns 1,725,338 shares in the Company. Mr. Balkany directly holds 30,809 shares in the Company.

(ii) Mr. Soden holds directly or indirectly 10,008 shares in the Company.

Shareholder distribution per December 31, 2017:

Amount of shares	# of shareholders	% of total	# of shares	Holding in %
1 - 1,000	2,605	69.86%	473,553	1.11%
1,001 - 5,000	515	13.81%	1,321,360	3.11%
5,001 - 10,000	197	5.28%	1,487,500	3.50%
10,001 - 100,000	336	9.01%	10,046,581	23.64%
100,001 - 1,000,000	70	1.88%	16,893,931	39.75%
1,000,001 +	6	0.16%	12,279,271	28.89%
Total	**3,729**	**100.00%**	**42,502,196**	**100.00%**

NOTE 10. OTHER CURRENT LIABILITIES

The breakdown of other current liabilities is below:

USD 000	2017	2016
Accruals including severance costs	239	644
Employee related costs payable (including taxes)	23	26
At December 31	**262**	**670**

NOTE 11. COMMITMENTS AND CONTINGENCIES

a) Commitments

Non-cancellable operating lease commitments
There were no non-cancellable operating lease commitments in 2017 or 2016 following the office closure in 2015.

NOTE 12. FINANCIAL MARKET RISK AND BUSINESS RISK

See details in Note 18 in the consolidated financial statements.

NOTE 13. GUARANTEES AND PLEDGES

The Company has provided a performance guarantee to the ANP, in terms of which the Company is liable for the commitments of Coral and Cavalo Marinho licenses in accordance with the given concessions of the licenses. The guarantee is unlimited.

Under section 479A of the UK Companies Act 2006; two of the Company's indirect subsidiaries Panoro Energy Limited (Registration number: 6386242) and African Energy Equity Resources Limited (Registration number: 5724928) have availed exemption for audit of their statutory financial statements pursuant to guarantees issued by the Company to indemnify the subsidiaries of any losses towards third parties that may arise in the financial year ended December 31, 2017 in such Companies. The Company can make an annual election to support such guarantee for each financial year.

NOTE 14. EVENTS SUBSEQUENT TO REPORTING DATE

Subsequent events can be referred to in Note 23 to the Group financial statements.

DECLARATION FROM THE BOARD OF DIRECTORS OF PANORO ENERGY ASA ON EXECUTIVE REMUNERATION POLICIES

(Ref. section 6-16a of the Norwegian Public Limited Companies act)

PART 1: SALARIES, BONUSES AND OTHER REMUNERATION PRINCIPLES

Panoro Energy ASA has established a compensation program for executive management that reflects the responsibility and duties as management of an international oil and gas company and at the same time contributes to add value for the Company's shareholders. The goal for the Board of Directors has been to establish a level of remuneration that is competitive both in domestic and international terms to ensure that the Group is an attractive employer that can obtain a qualified and experienced workforce. The compensation structure can be summarized as follows:

Compensation Element	Objective and Rational	Form	What the Element Rewards
Base Salary	A competitive level of compensation is provided for fulfilling position responsibilities	Cash	Knowledge, expertise, experience, scope of responsibilities and retention
Short-term Incentives	To align annual performance with Panoro's business objectives and shareholder interests. Short-term incentive pools increase or decrease based on business performance	Cash	Achievement of specific performance benchmarks and individual performance goals
Long-term Incentives	To promote commitment to achieving long-term exceptional performance and business objectives as well as aligning interests with the shareholders through ownership levels comprised of share options and share based awards	Restricted Share Units	Sustained performance results, share price increases and achievement of specific performance measures based on quantified factors and metrics

The Remuneration Committee oversees our compensation programs and is charged with the review and approval of the Company's general compensation strategies and objectives and the annual compensation decisions relating to our executives and to the broad base of Company employees. Its responsibilities also include reviewing management succession plans; making recommendations to the Board of Directors regarding all employment agreements, severance agreements, change in control agreements and any special supplemental benefits applicable to executives; assuring that the Company's incentive compensation program, including the annual, short term incentives and long- term incentive plans, is administered in a manner consistent with the Company's strategy; approving and/or recommending to the Board of Directors new incentive compensation plans and equity-based compensation plans; reviewing the Company's employee benefit programs; and recommending for approval all administrative changes to compensation plans that may be subject to the approval of the shareholders or the Board of Directors.

The Remuneration Committee seeks to structure compensation packages and performance goals for compensation in a manner that does not incentivize employees to take risks that are reasonably likely to have a material adverse effect on the Company. The Remuneration Committee designs long-term incentive compensation, including restricted share units, performance units and share options in such a manner that employees will forfeit their awards if their employment is terminated for cause. The Committee also retains the discretionary authority to reduce bonuses to reflect factors regarding individual performance that are not otherwise taken into account.

The Board of Directors, upon the Remuneration Committee's recommendation, has also renewed the previously adopted Share Ownership Guidelines (SOG) Policy for members of the executive management to ensure that they have meaningful economic stake in the Company. This policy was introduced in 2015. The SOG policy is designed to satisfy an individual senior executive's need for portfolio diversification, while maintain management share ownership at levels high enough to assure the Company's shareholders of managements' full commitment to value creation. Officers of the Company are required to invest in a number of shares valued at a multiple of their base salary in the amounts ranging from 3 times base salary for the CEO and 1 times the base salary of any other member of the executive management team. Under the current policy, the share ownership level is to be achieved by the time of the year 2021 Annual General Meeting.

Remuneration in 2017:
Remuneration for executive management for 2017 consisted of both fixed and variable elements. The fixed elements consisted of salaries and other benefits (health and pension), while the variable elements consisted of a performance based bonus arrangement and a restricted share unit scheme that was approved by the Board of Directors and the shareholders in the Annual General Meeting in 2015.

For 2017, the following was paid/incurred to the executives:

2017	**Short term benefits**			**Long term benefits**			
USD 000 (unless stated otherwise)	**Salary**	**Bonus**	**Benefits**	**Pension costs**	**Total**	**Number of RSUs awarded in 2017**	**Fair value of RSUs expensed**
John Hamilton, CEO	380	94	8	36	518	200,000	64
Qazi Qadeer, CFO	227	43	4	22	296	100,000	32
Richard Morton, Technical Director	239	45	4	23	311	80,000	26
Total	**846**	**182**	**16**	**81**	**1,125**	**380,000**	**122**

Any bonuses that were incurred and paid in 2017 were approved by the Board of Directors during 2017. The bonus paid in 2017 related to the achievement of performance standards set by the Board of Directors for the financial year 2016.

Evaluation, award and payment of cash bonuses is generally performed in the year subsequent to financial year end, unless stated otherwise. Any bonuses for 2017 performance will be awarded in the year 2018 and determined based on the criteria set by the remuneration committee that includes meeting milestones of measurable strategic value drivers, progress on portfolio of assets, and certain corporate objectives including reduction of administrative overhead costs and HSE performance.

Remuneration principles for 2018:
For 2018, remuneration for executive management consists of both fixed and variable elements. The fixed elements consist of salaries and other benefits (health and pension), while the variable elements consist of a performance-based bonus arrangement and a restricted share unit scheme that was approved by the Board of Directors and the Company's shareholders in 2015. Since the restricted share unit plan of 2015 will expire at the 2018 AGM, the Board of Directors has proposed that the shareholders approve a new restricted share unit plan.

Any cash bonuses to members of the executive management for 2018 will be capped at 50% of annual base salary. Evaluation, award and payment of cash bonuses is generally performed in the year subsequent to the financial year end 2018. The annual bonus for 2018 performance will be awarded in the year 2019 and determined based on the criteria proposed by the Remuneration Committee and approved by the Board of Directors. Such criteria may include meeting milestones of measurable strategic value drivers, progress on portfolio of assets, and certain corporate objectives including reduction of administrative overhead costs and HSE performance. These criteria will be individually tailored for each member of the executive team and will be determined by the Board of Directors as soon as is practicable after the reporting period.

Severance payments etc:
Per the respective terms of employment, the CEO is entitled to 12 months of base salary in the event of a change of control; whereby a tender offer is made or consummated for the ownership of more than 50% or more of the outstanding voting securities of the Company; or the Company is merged or consolidated with another corporation and as a result of such merger or consolidation less than 50.1% of the outstanding voting securities of the surviving entity or resulting corporation

are owned in the aggregate by the persons by the entities or persons who were shareholders of the Company immediately prior to such merger or consolidation; or the Company sells substantially all of its assets to another corporation that is not a wholly owned subsidiary. The CFO and Technical Director are entitled to 6 months of base salary in the event of a change of control.

Pensions:
The Company is required to have an occupational pension scheme in accordance with the Norwegian law on required occupational pension ("Lov om obligatorisk tjenestepensjon"). The Company contributes to an external defined contribution scheme and therefore no pension liability is recognized in the statement of financial position. Since the Company no longer employs any staff in Norway, this scheme is effectively redundant.

In the UK, the Company's subsidiary that employs the staff, contributes a fixed amount per Company policy in an external defined contribution scheme. As such, no pension liability is recognised in the statement of financial position in relation to Company's subsidiaries either.

2017 – Compliance:
In 2017, the executives received base salaries and cash incentive bonuses in line with the executive remuneration policies as presented to the 2017 Annual General Meeting.

PART 2: SHARE BASED INCENTIVES

In June 2017, 420,000 Restricted Share Units were awarded under and in accordance with the Company's RSU scheme to the employees of the Company under the long term incentive compensation plan approved by the shareholders. One Restricted Share Unit ("RSU") entitles the holder to receive one share of capital stock of the Company against payment in cash of the par value for the share. The par value is currently NOK 0.05 per share. Vesting of the RSUs is time based. The standard vesting period is 3 years, where 1/3 of the RSUs vest after one year, 1/3 vest after 2 years, and the final 1/3 vest after 3 years from grant. RSUs vest automatically at the respective vesting dates and the holder will be issued the applicable number of shares as soon as possible thereafter.

For 2018 the Board of Directors will only award share based incentives in line with any shareholder approved program. Awards of share based incentives will in value (calculated at the time of grant) be capped to 100% of the annual base salary for the CEO and 50% of the annual base salary for other members of the executive management.

STATEMENT OF DIRECTORS' RESPONSIBILITY

Pursuant to the Norwegian Securities Trading Act section 5-5 with pertaining regulations we hereby confirm that, to the best of our knowledge, the company's financial statements for 2017 have been prepared in accordance with IFRS, as provided for by the EU, and in accordance with the requirements for additional information provided for by the Norwegian Accounting Act. The information presented in the financial statements gives a true and fair picture of the company's liabilities, financial position and results viewed in their entirety.

To the best of our knowledge, the Board of Directors' Report gives a true and fair picture of the development, performance and financial position of the company, and includes a description of the principal risk and uncertainty factors facing the company. Additionally, we confirm to the best of our knowledge that the report "Payments to governments" as provided in a separate section in this annual report has been prepared in accordance with the requirements in the Norwegian Securities Trading Act Section 5-5a with pertaining regulations.

April 30, 2018
The Board of Directors
Panoro Energy ASA

Julien Balkany *Chairman of the Board*	Garrett Soden *Non-Executive Director*	Torstein Sanness *Non-Executive Director*
Alexandra Herger *Non-Executive Director*	Hilde Ådland *Non-Executive Director*	John Hamilton *Chief Executive Officer*

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INDEPENDENT AUDITOR'S REPORT

To the Annual Shareholders' Meeting of Panoro Energy ASA

Report on the audit of the financial statements

Opinion

We have audited the financial statements of Panoro Energy ASA comprising the financial statements of the parent company and the Group. The financial statements of the parent company comprise the balance sheet as at 31 December 2017, the income statement and statements of cash flows for the year then ended and notes to the financial statements, including a summary of significant accounting policies. The consolidated financial statements comprise the statement of financial position as at 31 December 2017, statements of comprehensive income, cash flows and changes in equity for the year then ended and notes to the financial statements, including a summary of significant accounting policies.

In our opinion,

- the financial statements are prepared in accordance with the law and regulations;
- the financial statements present fairly, in all material respects, the financial position of the parent company as at 31 December 2017, and of its financial performance and its cash flows for the year then ended in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway;
- the consolidated financial statements present fairly, in all material respects the financial position of the Group as at 31 December 2017 and of its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards as adopted by the EU.

Basis for opinion

We conducted our audit in accordance with laws, regulations, and auditing standards and practices generally accepted in Norway, including International Standards on Auditing (ISAs). Our responsibilities under those standards are further described in the *Auditor's responsibilities for the audit of the financial statements* section of our report. We are independent of the Company and the Group in accordance with the ethical requirements that are relevant to our audit of the financial statements in Norway, and we have fulfilled our ethical responsibilities as required by law and regulations. We have also complied with our other ethical obligations in accordance with these requirements. 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 judgment, were of most significance in our audit of the financial statements for 2017. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the financial statements.

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Impairment of oil and gas assets related to the Aje field

As of 31 December 2017, the book value of oil and gas assets related to the Aje field amounted to USD 15.3 million after taking into account an impairment charge of USD 32.8 million recognised in the financial statements for the year ended 31 December 2017. Management assessed and concluded that there were impairment triggers present. These triggers included the decline in production performance, the accumulated costs on the Aje-5 well intervention and the decline in Cenomanian Oil reserves as per the most recent independent reserves report.

Management has determined the recoverable amount as of year end based on fair value less cost to sell considering the potential divestment structures under consideration. This impairment assessment was a key consideration during our audit as the book value of the assets constitutes a significant part of the Group's total assets in the consolidated financial statements and there is considerable uncertainty inherent in the estimate of fair value less cost to sell.

We obtained an understanding of the process in relation to the impairment assessment and identified controls that are in place. We assessed the method used. Further, we corroborated the basis of the fair value less cost to sell towards Management's evaluation of the net proceeds expected to be realised in a potential sale of the assets by considering the relevant market input and the basis for the assumptions used. We tested the mathematical accuracy of the calculation.

We also assessed the Company's disclosures included in Note 2.3 Summary of significant accounting principles applicable for 2017 and Note 9D Impairment in oil and gas interests.

Other information

Other information consists of the information included in the Company's annual report other than the financial statements and our auditor's report thereon. The Board of Directors and Chief Executive Officer (management) are responsible for the other information. Our opinion on the financial statements 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 statements, our responsibility is to read the other information, and, in doing so, consider whether the other information is materially inconsistent with the financial statements 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 management for the financial statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the Norwegian Accounting Act and accounting standards and practices generally accepted in Norway for the financial statements of the parent company and International Financial Reporting Standards as adopted by the EU for the financial statements of the Group, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting, unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Auditor's responsibilities for the audit of the financial statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that

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includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with ISAs 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 these financial statements.

As part of an audit in accordance with law, regulations and generally accepted auditing principles in Norway, including ISAs, we exercise professional judgment and maintain professional scepticism throughout the audit. We also:

- identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control
- evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Group to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

Report on other legal and regulatory requirements

Opinion on the Board of Directors' report and on the statements on corporate governance and corporate social responsibility

Based on our audit of the financial statements as described above, it is our opinion that the information presented in the Board of Directors' report and in the statements on corporate governance and corporate social responsibility concerning the financial statements, the going concern assumption and proposal for the allocation of the result is consistent with the financial statements and complies with the law and regulations.

Opinion on registration and documentation

Based on our audit of the financial statements as described above, and control procedures we have considered necessary in accordance with the International Standard on Assurance Engagements (ISAE) 3000, «Assurance Engagements Other than Audits or Reviews of Historical Financial Information», it is our opinion that management has fulfilled its duty to ensure that the Company's accounting information is properly recorded and documented as required by law and bookkeeping standards and practices accepted in Norway.

Stavanger, 30 April 2018
ERNST & YOUNG AS

Tor Inge Skjellevik
State Authorised Public Accountant (Norway)

STATEMENT ON CORPORATE GOVERNANCE IN PANORO ENERGY ASA

Panoro Energy ASA ("Panoro" or "the Company") aspires to ensure confidence in the Company and the greatest possible value creation over time through efficient decision making, clear division of roles between shareholders, management and the Board of Directors ("the Board") as well as adequate communication.

Panoro Energy seeks to comply with all the requirements covered in The Norwegian Code of Practice for Corporate Governance. The latest version of the Code of October 30, 2014 is available on the website of the Norwegian Corporate Governance Board, www.nues.no. The Code is based on the "comply or explain" principle, in that companies should explain alternative approaches to any specific recommendation.

1. IMPLEMENTATION AND REPORTING ON CORPORATE GOVERNANCE

The main objective for Panoro's Corporate Governance is to develop a strong, sustainable and competitive company in the best interest of the shareholders, employees and society at large, within the laws and regulations of the respective country. The Board of Directors (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.

The Board will give high priority to finding the most appropriate working procedures to achieve, inter alia, the aims covered by these Corporate Governance guidelines and principles.

The Norwegian Code of Practice for Corporate Governance as of October 30, 2014 comprises 15 points. The Corporate Governance report is available on the Company's website www.panoroenergy.com.

2. BUSINESS

Panoro Energy ASA is an independent E&P company based in London and listed on the Oslo Stock Exchange. The Company holds production, exploration and development assets in West Africa, namely the Dussafu License offshore southern Gabon, and OML 113 offshore western Nigeria. In addition to discovered hydrocarbon resources and reserves, both assets also hold significant exploration potential. Panoro Energy was formed through the merger of Norse Energy's former Brazilian business and Pan-Petroleum on June 29, 2010. The Company is listed on the Oslo Stock Exchange with ticker PEN.

The Company's business is defined in the Articles of Association §2, which states:
"The Company's business shall consist of exploration, production, transportation and marketing of oil and natural gas and exploration and/or development of other energy forms, sale of energy as well as other related activities. The business might also involve participation in other similar activities through contribution of equity, loans and/or guarantees".

Panoro Energy currently has only one reportable segment with exploration and production of oil and gas, by geographic West Africa. In West Africa, the Company participates in a number of licenses in Nigeria and Gabon.

Vision statement
Our vision is to use our experience and competence in enhancing value in projects in West Africa to the benefit of the countries we operate in and the shareholders of the Company.

3. EQUITY AND DIVIDENDS

Panoro Energy's Board of Directors will ensure that the Company at all times has an equity capital at a level appropriate to its objectives, strategy and risk profile. The oil and gas E&P business is highly capital dependent, requiring Panoro Energy to be sufficiently capitalized. The Board needs to be proactive in order for Panoro Energy to be prepared for changes in the market.

Mandates granted to the Board to increase the Company's share capital will normally be restricted to defined purposes. Any acquisition of our shares will be carried out through a regulated marketplace at market price, and the Company will not deviate from the principle of equal treatment of all shareholders. If there is limited liquidity in the Company's shares at the time of such transaction, the Company will consider other ways to ensure equal treatment of all shareholders.

Mandates granted to the Board for issue of shares for different purposes will each be considered separately by the General Meeting. Mandates granted to the Board to issue new shares are normally limited in time to the following year's Annual General Meeting. Any decision to deviate from the principle of equal treatment by waiving the pre-emption rights of existing shareholders to subscribe for shares in the event of an increase in share capital will be justified and disclosed in the stock exchange announcement of the increase in share capital. Such deviation will be made only in the common interest of the shareholders of the Company.

Panoro Energy is in a phase where investments in the Company's operations are required to enable future growth, and is therefore not in a position to distribute dividends. Payment of dividends will be considered in the future, based on the Company's capital structure and dividend capacity as well as the availability of alternative investments.

4. EQUAL TREATMENT OF SHAREHOLDERS AND TRANSACTIONS WITH CLOSE ASSOCIATES

Panoro Energy has one class of shares representing one vote at the Annual General Meeting. The Articles of Association contains no restriction regarding the right to vote.

All Board members, employees of the Company and close associates must internally clear potential transactions in the Company's shares or other financial instruments related to the Company prior to any transaction. All transactions between the Company and shareholders, shareholder's parent company, members of the Board of Directors, executive personnel or close associates of any such parties, are governed by the Code of Practice and the rules of the Oslo Stock Exchange, in addition to statutory law. Any transaction with close associates will be evaluated by an independent third party, unless the transaction requires the approval of the General Meeting pursuant to the requirements of the Norwegian Public Limited Liabilities Companies Act. Independent valuations will also be arranged in respect of transactions between companies in the same Group where any of the companies involved have minority shareholders. Any transactions with related parties, primary insiders or employees shall be made in accordance with Panoro Energy's own instructions for Insider Trading.
The Company has guidelines to ensure that members of the Board and executive personnel notify the Board if they have any material direct or indirect interest in any transaction entered into by the Company.

5. FREELY NEGOTIABLE SHARES

The Panoro Energy ASA shares are listed on the Oslo Stock Exchange. There are no restrictions on negotiability in Panoro Energy's Articles of Association.

6. GENERAL MEETINGS

Panoro Energy's Annual General Meeting will be held by the end of June each year. The Board of Directors take necessary steps to ensure that as many shareholders as possible may exercise their rights by participating in General Meetings of the Company, and to ensure that General Meetings are an effective forum for the views of shareholders and the Board. An invitation and agenda (including proxy) will be sent out no later than 21 days prior to the meeting to all shareholders in the Company. The invitation will also be distributed as a stock exchange notification. The invitation and support information on the resolutions to be considered at the General Meeting will furthermore normally be posted on the Company's website www.panoroenergy.com no later than 21 days prior to the date of the General Meeting.

The recommendation of the Nomination Committee will normally be available on the Company's website at the same time as the notice.

Panoro Energy will ensure that the resolutions and supporting information distributed are sufficiently detailed and comprehensive to allow shareholders to form a view on all matters to be considered at the meeting.

According to Article 7 of the Company's Articles of Association, registrations for the Company's General Meetings must be received at least five calendar days before the meeting is held.

The Chairman of the Board and the CEO of the Company are normally present at the General Meetings. Other Board members and the Company's auditor will aim to be present at the General Meetings. Members of the Nomination Committee are requested to be present at the AGM of the Company. An independent person to chair the General Meeting will, to the extent possible, be appointed. Normally the General Meetings will be chaired by the Company's external corporate lawyer.

Shareholders who are unable to attend in person will be given the opportunity to vote by proxy. The Company will nominate a person who will be available to vote on behalf of shareholders as their proxy. Information on the procedure for representation at the meeting through proxy will be set out in the notice for the General Meeting. A form for the appointment of a proxy, which allows separate voting instructions for each matter to be considered by the meeting and for each of the candidates nominated for elections will be prepared. Dividend, remuneration to the Board and the election of the auditor, will be decided at the AGM. After the meeting, the minutes are released on the Company's website.

7. NOMINATION COMMITTEE

The Company shall have a Nomination Committee consisting of 2 to 3 members to be elected by the Annual General Meeting for a two year period. The Annual General Meeting elects the members and the Chairperson of the Nomination Committee and determines the committee's remuneration. The Company will provide information on the member of the Nomination Committee on its website. The Company will further give notice on its website, in good time, of any deadlines for submitting proposals for candidates for election to the Board of Directors and the Nomination Committee.

The Company aims at selecting the members of the Nomination Committee taking into account the interests of shareholders in general. The majority of the Nomination Committee shall as a rule be independent of the Board and the executive management. The Nomination Committee currently consists of three members, whereof all members are independent of the Board and the executive management.

The Nomination Committee's duties are to propose to the General Meeting shareholder elected candidates for election to the Board, and to propose remuneration to the Board. The Nomination Committee justifies its recommendations and the recommendations take into account the interests of shareholders in general and the Company's requirements in respect of independence, expertise, capacity and diversity.

The Annual General Meeting may stipulate guidelines for the duties of the Nomination Committee.

8. CORPORATE ASSEMBLY AND BOARD OF DIRECTORS – COMPOSITION AND INDEPENDENCE

The composition of the Board ensures that the Board represents the common interests of all shareholders and meets the Company's need for expertise, capacity and diversity. The members of the Board represent a wide range of experience including shipping, offshore, energy, banking and investment. The composition of the Board ensures that it can operate independently of any special interests. Members of the Board are elected for a period of two years. Recruitment of members of the Board may be phased so that the entire Board is not replaced at the same time. The Chairman of the Board of Directors is elected by the General Meeting. The Company has not experienced a need for a permanent deputy Chairman. If the Chairman cannot participate in the Board meetings, the Board will elect a deputy Chairman on an ad-hoc basis. The Company's website and annual report provides detailed information about the Board members expertise and independence. The Company has a policy whereby the members of the Board of Directors are encouraged to own shares in the Company, but to dissuade from a short-term approach which is not in the best interests of the Company and its shareholders over the longer term.

9. THE WORK OF THE BOARD OF DIRECTORS

The Board has the overall responsibility for the management and supervision of the activities in general. The Board decides the strategy of the Company and has the final say in new projects and/or investments. The Board's instructions for its own work as well as for the executive management have particular emphasis on clear internal allocation of responsibilities and duties. The Chairman of the Board ensures that the Board's duties are undertaken in efficient and correct manner. The Board shall stay informed of the Company's financial position and ensure adequate control of activities, accounts and asset management. The Board member's experience and skills are crucial to the Company both from a financial as well as an operational perspective. The Board of Directors evaluates its performance and expertise annually. The CEO is responsible for the Company's daily operations and ensures that all necessary information is presented to the Board.

An annual schedule for the Board meetings is prepared and discussed together with a yearly plan for the work of the Board.

Should the Board need to address matters of a material character in which the Chairman is or has been personally involved, the matter will be chaired by another member of the Board to ensure a more independent consideration.

In addition to the Nomination Committee elected by the General Meeting, the Board has an Audit Committee and a Remuneration Committee as sub-committees of the Board. The members are independent of the executive management.

Currently the Audit Committee consists of the complete Board. The reason for this is the rather low number of directors in the Company, which has led the Board to conclude that it is currently more efficient for the Board function that all directors also are members of the Audit Committee. This practice will be further assessed in the future.

10. RISK MANAGEMENT AND INTERNAL CONTROL

Financial and internal control, as well as short- and long term strategic planning and business development, all according to Panoro Energy's business idea and vision and applicable laws and regulations, are the Board's responsibilities and the essence of its work. This emphasizes the focus on ensuring proper financial and internal control, including risk control systems.

The Board approves the Company's strategy and level of acceptable risk, as documented in the guiding tool "Risk Management" described in the relevant note in the consolidated financial statements in the Annual Report.

The Board carries out an annual review of the Company's most important areas of exposure to risk and its internal control arrangements.

For further details on the use of financial instruments, refer to relevant note in the consolidated financial statements in the Annual Report and the Company's guiding tool "Financial Risk Management" described in relevant note in the consolidated financial statements in the Annual Report.

11. REMUNERATION OF THE BOARD OF DIRECTORS

The remuneration to the Board will be decided by the Annual General Meeting each year.

Panoro Energy is a diversified company, and the remuneration will reflect the Board's responsibility, expertise, the complexity and scope of work as well as time commitment.

The remuneration to the Board is not linked to the Company's performance, and share options will normally not be granted to Board members. Remuneration in addition to normal director's fee will be specifically identified in the Annual Report.

Members of the Board normally do not take on specific assignments for the Company in addition to their appointment as a member of the Board.

12. REMUNERATION OF THE EXECUTIVE PERSONNEL

The Board has established guidelines for the remuneration of the executive personnel. The guidelines set out the main principles applied in determining the salary and other remuneration of the executive personnel. The guidelines ensure convergence of the financial interests of the executive personnel and the shareholders.

Panoro Energy has appointed a Remuneration Committee (RC) which meets regularly. The objective of the committee is to determine the compensation structure and remuneration level of the Company's CEO. Remuneration to the CEO shall be at market terms and decided by the Board and made official at the AGM every year. Remuneration to other key executives shall be proposed by the CEO to the RC.

The remuneration shall, both with respect to the chosen kind of remuneration and the amount, encourage addition of values to the Company and contribute to the Company's common interests – both for management as well as the owners.

Detailed information about options and remuneration for executive personnel and Board members is provided in the Annual Report pursuant to and in accordance with section 6-16a of the Norwegian Public Limited Companies Act. The guidelines are normally presented to the Annual General Meeting also as a separate attachment to the Annual General Meeting notice.

13. INFORMATION AND COMMUNICATION

The Company has established guidelines for the Company's reporting of financial and other information.

The Company publishes an annual financial calendar including the dates the Company plans to publish the quarterly results and the date for the Annual General Meeting. The calendar can be found on the Company's website, and will also be distributed as a stock exchange notification and updated on Oslo Stock Exchange's website. The calendar is published at the end of a fiscal year, according to the continuing obligations for companies listed on the Oslo Stock Exchange. The calendar is also included in the Company's quarterly financial reports.

All shareholders information is published simultaneously on the Company's web site and to appropriate financial news media.

Panoro Energy normally makes four quarterly presentations a year to shareholders, potential investors and analysts in connection with quarterly earnings reports. The quarterly presentations are held through audio conference calls to facilitate participation by all interested shareholders, analysts, potential investors and members of the financial community. A question and answer session is held at the end of each presentation to allow management to answer the questions of attendees. A recording of the conference call presentation is retained on the Company's website www. panoroenergy.com for a limited number of days.

The Company also makes investor presentations at conferences in and out of Norway. The information packages presented at such meetings are published simultaneously on the Company's web site.

The Chairman, CEO and CFO of Panoro Energy are the only people who are authorized to speak to, or be in contact with the press, unless otherwise described or approved by the Chairman, CEO and/or CFO.

14. TAKEOVERS

Panoro Energy has established the following guiding principles for how the Board of Directors will act in the event of a take-over bid.

As of today the Board does not hold any authorizations as set forth in Section 6-17 of the Securities Trading Act, to effectuate defence measures if a takeover bid is launched on Panoro Energy.

The Board may be authorized by the General Meeting to acquire its own shares, but will not be able to utilize this in order to obstruct a takeover bid, unless approved by the General Meeting following the announcement of a takeover bid.

The Board of Directors will generally not hinder or obstruct take-over bids for the Company's activities or shares.

As a rule the Company will not enter into agreements with the purpose to limit the Company's ability to arrange other bids for the Company's shares unless it is clear that such an agreement is in the common interest of the Company and its shareholders. As a starting point the same applies to any agreement on the payment of financial compensation to the bidder if the bid does not proceed. Any financial compensation will as a rule be limited to the costs the bidder has incurred in making the bid. The Company will generally seek to disclose agreements entered into with the bidder that are material to the market's evaluation of the bid no later than at the same time as the announcement that the bid will be made is published.

In the event of a take-over bid for the Company's shares, the Board of Directors will not exercise mandates or pass any resolutions with the intention of obstructing the take-over bid unless this is approved by the General Meeting following announcement of the bid.

If an offer is made for the Company's shares, the Board will issue a statement evaluating the offer and making a recommendation as to whether shareholders should or should not accept the offer. The Board will also arrange a valuation with an explanation from an independent expert. The valuation will be made public no later than at the time of the public disclosure of the Board's statement. Any transactions that are in effect a disposal of the Company's activities will be decided by a General Meeting.

15. AUDITOR

The auditor will be appointed by the General Meeting.

The Board has appointed an Audit Committee as a sub-committee of the Board, which will meet with the auditor regularly. The objective of the committee is to focus on internal control, independence of the auditor, risk management and the Company's financial standing.

The auditors will send a complete Management Letter/ Report to the Board – which is a summary report with comments from the auditors including suggestions of any improvements if needed. The auditor participates in meetings of the Board of Directors that deal with the annual accounts, where the auditor reviews any material changes in the Company's accounting principles, comments on any material estimated accounting figures and reports all material matters on which there has been disagreement between the auditor and the executive management of the Company.

In view of the auditor's independence of the Company's executive management, the auditor is also present in at least one Board meeting each year at which neither the CEO nor other members of the executive management are present.

Panoro Energy places importance on independence and has established guidelines in respect of retaining the Company's external auditor by the Company's executive management for services other than the audit.

The Board reports the remuneration paid to the auditor at the Annual General Meeting, including details of the fee paid for audit work and any fees paid for other specific assignments.

REPORTING OF PAYMENTS TO GOVERNMENTS

This report is prepared in accordance with the Norwegian Accounting Act § 3-3d. It states that the companies engaged in the activities within the extractive industries shall annually prepare and publish a report containing information about their payments to governments at country and project level. The Ministry of Finance has issued a regulation (F20.12.2013 nr 1682 - "the regulation") stipulating that the reporting obligation only apply to reporting entities above a certain size and to payments above certain threshold amounts. In addition, the regulation stipulates that the report shall include other information than payments to governments, and provides more detailed rules with regard to definitions, publication and group reporting.

This report contains information for the activity in the whole fiscal year 2017 for Panoro Energy ASA.

The management of Panoro has applied judgement in interpretation of the wording in the regulation with regard to the specific type of payments to be included in this report, and on what level it should be reported. When payments are required to be reported on a project-by-project basis, it is reported on a field-by-field basis. Per management's interpretation of the regulation, reporting requirements only stipulate disclosure of gross amounts on operated licences as all payments within the license performed by Non-operators, normally will be cash calls transferred to the operator and will as such not be payments to government.

Although Panoro Energy, through its subsidiaries, has extractive activities and ownership interest in two licences in West Africa, namely Dussafu license offshore Gabon and OML-113 offshore Nigeria; both of the licenses are non-operated and as such only cash calls are disbursed to operating partners and therefore none of the payments during 2017 can be construed as payments direct to governments under the regulation. As such, no payment will be disclosed in these cases, unless the operator is a state-owned entity and it is possible to distinguish the payment from other cost recovery items. Aje oil production continued through 2017 and the Group continues to receive revenues for its interest in OML 113. There are customary royalty and taxes due on oil production in Nigeria and as of December 31, 2017 the Group had no tax liability and USD 112 thousand of net production royalty was paid indirectly to the government authorities in Nigeria. The royalty payments were withheld at source from the cargo proceeds by the Operator. As a result, the Company or its subsidiaries have not made any direct payments in relation to the non-operated assets to the respective governments of Gabon and Nigeria.

CORPORATE SOCIAL RESPONSIBILITY/ ETHICAL CODE OF CONDUCT

1. ABOUT PANORO

Panoro Energy ASA is an international independent E&P company listed on Oslo Stock Exchange with ticker PEN with a primary office in London. The company is focused on its high quality production and development assets in West Africa, namely the Dussafu License offshore southern Gabon, and OML113 offshore western Nigeria. In addition to discovered hydrocarbon resources and reserves, both assets also hold significant exploration potential.

Panoro's main purpose is to capitalize on the value of its assets. However, the Company acknowledges its responsibility for the methods by which this is achieved. The principles set out below seek to ensure that Panoro operates in a socially and environmentally responsible manner, encouraging a positive impact through its activities and those of its partners and other stakeholders.

2. MESSAGE FROM THE CEO

Being a commercial entity, Panoro is focused on creating shareholder value. Nevertheless, we are mindful of the impact of our activities to achieve this goal; we are firmly committed to embracing our social and environmental responsibility, and to honouring the letter and the spirit of the UN Global Compact principles. We believe that this is the right approach for all our stakeholders, including but not limited to the host countries, the local communities, our shareholders and business partners.

We are committed to ensuring that our presence has a positive impact wherever we work and invest. We have therefore adopted this Ethical Code of Conduct ("ECOC").

3. FRAMEWORK AND SCOPE OF THE ETHICAL CODE OF CONDUCT OF PANORO

3.1 Panoro as a company, as well as its individual employees, will commit to follow this ECOC.

3.2 Equally, we will work through our stakeholders and partners to ensure that we adhere to the values expressed in the ECOC.

3.3 Finally, the ECOC is based on the ten principles expressed in the UN Global Compact.

4. THE UN GLOBAL COMPACT PRINCIPLES

The UN Global Compact's ten principles in the areas of human rights, labour, the environment and anti-corruption enjoy universal consensus and are derived from:

- The Universal Declaration of Human Rights
- The International Labour Organization's Declaration on Fundamental Principles and Rights at Work
- The Rio Declaration on Environment and Development
- The United Nations Convention Against Corruption

The UN Global Compact asks companies to embrace, support and enact, within their sphere of influence, a set of core values in the areas of human rights, labour standards, the environment and anti-corruption:

Human Rights
- **Principle 1:** Businesses should support and respect the protection of internationally proclaimed human rights; and
- **Principle 2:** make sure that they are not complicit in human rights abuses

Labour
- **Principle 3:** Businesses should uphold the freedom of association and the effective recognition of the right to collective bargaining;
- **Principle 4:** the elimination of all forms of forced and compulsory labour;
- **Principle 5:** the effective abolition of child labour; and
- **Principle 6:** the elimination of discrimination in respect of employment and occupation

Environment
- **Principle 7:** Businesses should support a precautionary approach to environmental challenges;
- **Principle 8:** undertake initiatives to promote greater environmental responsibility; and
- **Principle 9:** encourage the development and diffusion of environmentally friendly technologies

Anti-Corruption
- **Principle 10:** Businesses should work against corruption in all its forms, including extortion and bribery

5. HOST COUNTRIES AND LOCAL COMMUNITIES

In addition to these principles, Panoro is concerned with the responsibility of the Company and its operations to the host country and the local community. Wherever Panoro operates, the Company will be committed to:

- observe local laws and rules
- respect the sovereignty of the state
- observe and, through our example and that of our stakeholders, promote the rule of law
- encourage the employment of local staff
- engage in capacity building, through the transfer of skills and technologies
- work with local communities by contributing to improve their health, education and welfare
- respect indigenous people and their traditions
- minimize disturbances that may be caused by our operations
- be mindful of the impact of our security arrangements on local communities
- refrain from any involvement in tribal or internal armed conflicts or acts of violence

6. STAKEHOLDERS

The stakeholders of Panoro are defined as entities that are influenced by, or have influence on, the development of Panoro's assets. Panoro aims to commit to its ethical principles by working through its stakeholders, as well as monitoring how those stakeholders view Panoro's implementation of its ECOC.

Stakeholder	Influence	Implementation of ECOC
Employees	Panoro recognizes its influence and its responsibility to its employees, as well as to their close surroundings. Equally, the Company recognizes the importance of attracting and retaining talent in order to fulfil its business and ethical goals.	Panoro will consistently train its employees to adhere to company standards and procedures. Each employee is expected to learn about and to undertake training on the ECOC on a regular basis.
Partners	Panoro operates and maximizes the value of its assets mainly in partnership with other entities.	Through partnership agreements, as well as through formal and informal communication, Panoro will seek to use its influence to implement its ECOC throughout its joint operations.
Operators	The operators are the entities that conduct the actual operation of the assets.	Through joint operation agreements, as well as through formal and informal communication, Panoro will seek to maintain the highest ethical standards in all operations; focusing on HS&Q, environment and all other principles listed above in sections 4 and 5.
Shareholders	The Panoro shareholders, including potential shareholders.	Panoro will seek to minimize shareholder risk and maximize value creation by adhering to the highest ethical standards in terms of environmental, legal and other risks based on the above principles. Panoro follows a strict code of governance based on international law and business practice.
Local community	The communities in which the Panoro assets are placed include national authorities and different government bodies, as well as local unions, tribes and other community members.	Each asset has formal meeting points and communication lines set up within its operational structure. Panoro will seek to use these to address issues of interest based on the ECOC, including corruption, HS&Q and any other issues listed above.

GLOSSARY AND DEFINITIONS

Bbl	One barrel of oil, equal to 42 US gallons or 159 liters
Bm3	Billion cubic meters
BOE	Barrel of oil equivalent
Btu	British Thermal Units, the energy content needed to heat one pint of water by one degree Fahrenheit
M3	Cubic meters
MMbbls	Million barrels of oil
MMBOE	Million barrels of oil equivalents
MMBtu	Million British thermal units
MMm3	Million cubic meters

CONVERSION FACTORS

Natural gas and LNG	To billion cubic metres NG	Billion cubic feet NG	Million tonnes oil equivalent	Million tonnes LNG	Trillion British thermal units	Million barrels oil equivalent
From			Multiply by			
1 billion cubic metres NG	1.00	35.30	0.90	0.73	36.00	6.29
1 billion cubic feet NG	0.028	1.00	0.026	0.021	1.03	0.18
1 million tonnes oil equivalent	1.111	39.20	1.00	0.805	40.40	7.33
1 million tonnes LNG	1.38	48.70	1.23	1.00	52.00	8.68
1 trillion British thermal units	0.028	0.98	0.025	0.02	1.00	0.17
1 million barrels oil equivalent	0.16	5.61	0.14	0.12	5.80	1.00

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APPENDIX 4 – OMV STATEMENT OF FINANCIAL POSITION

Unaudited Statement of Financial Position

OMV Tunisia Upstream GmbH	Opening balance	Consolidation adjustments	OMV Tunisia Upstream GmbH opening balance	OMV Tunisia Upstream GmbH opening balance 60 %
	31/12/2017	31/12/2017	31/12/2017	31/12/2017
(Unaudited figures in USD '000)	(unaudited)	(unaudited)	(unaudited)	(unaudited)
ASSETS				
Non-current assets				
Intangible assets				
Licenses and exploration assets	0	0	0	0
Total intangible assets	**0**	**0**	**0**	**0**
Tangible assets				
Production assets and equipment	32,593	0	32,593	19,556
Development assets	921	0	921	553
Deferred tax assets	5,138	0	5,138	3,083
Total tangible assets	**38,653**	**0**	**38,653**	**23,192**
Total non-current assets	**38,653**	**0**	**38,653**	**23,192**
Current assets				
Crude oil inventory	754	0	754	453
Inventories	6,452	0	6,452	3,871
Trade and other receivables	4,312	0	4,312	2,587
Total current assets	**11,518**	**0**	**11,518**	**6,911**
TOTAL ASSETS	**50,171**	**0**	**50,171**	**30,103**
EQUITY AND LIABILITIES				
Equity				
Share capital	41	0	41	25
Additional paid-in capital	5,961	0	5,961	3,576
Total paid-in equity	**6,002**	**0**	**6,002**	**3,601**
Other reserves	0	0	0	0
Retained earnings	0	0	0	0
Total equity attributable to shareholder of the parent	**6,002**	**0**	**6,002**	**3,601**
Non-current liabilities				
Decommissioning liability	28,439	0	28,439	17,063
Deferred tax liabilities	5,377	0	5,377	3,226
Other non-current liabilities	1,509	0	1,509	905
Total non-current liabilities	**35,324**	**0**	**35,324**	**21,195**
Current liabilities				
Corporation tax liability	8,845	0	8,845	5,307
Total current liabilities	**8,845**	**0**	**8,845**	**5,307**
TOTAL EQUITY AND LIABILITIES	**50,171**	**0**	**50,171**	**30,103**

APPENDIX 5 – GAFFNEY, CLINE & ASSOCIATES - COMPETENT PERSON'S REPORT ON CERTAIN OIL AND GAS ASSETS IN TUNISIA AS AT 30TH JUNE, 2018

Competent Person's Report on Certain Oil and Gas Assets in Tunisia as at 30th June, 2018

Prepared for

Panoro Energy Limited

5th November, 2018

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Gaffney, Cline & Associates

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Richard Morton
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Dear Richard,

Competent Person's Report on Certain Oil and Gas Assets in Tunisia as at 30th June, 2018

Introduction

At the request of Panoro Energy Limited (Panoro), Gaffney, Cline & Associates (GCA) has prepared this Competent Person's Report on the Reserves and Contingent Resources in certain oil and gas assets in Tunisia as at an Effective Date of 30th June, 2018. Specifically, GCA has conducted a technical and economic audit of the Reserves and Contingent Resources attributable to the interest in these assets held by OMV Tunisia Upstream GmbH, which Panoro intends to acquire. The acquisition has been code-named "Project Tasneem".

This report has been prepared for use in support of fund raising activities being undertaken by Panoro to fund the acquisition and is intended to be included in a Prospectus to be submitted to the Oslo Bors for this purpose.

The assessment has been conducted on the basis of a data set of technical information made available to GCA by or at the direction of Panoro including: details of concession interests and agreements, geological and geophysical data, interpretations and technical reports, historical production and engineering data, cost and commercial data, and development plans.

This report relates specifically and solely to the subject matter as defined in the scope of work, as set out herein, and is conditional upon the specified assumptions. The report must be considered in its entirety and must only be used for the purpose for which it is intended.

A glossary of abbreviations used in this report is contained in Appendix I.

Summary

License Summary

Panoro intends to acquire a 100% share in OMV Tunisia Upstream GmbH (OMV) that holds a 49% interest in five oil field concessions in Tunisia – Cercina, Cercina Sud, Rhemoura, El Ain/Gremda and El Hajeb/Guebiba. OMV also holds a 50% interest in the Joint Venture (JV) Thyna Petroleum Services (TPS), which is operating the concessions. The other 51% interest in the assets and 50% interest in TPS is held by the Tunisian state oil company ETAP. OMV acquired its interest in these assets and in TPS from Preussag Energy Intern GmbH (Preusag) in 2003. Table 1 summarizes the license ownership details for the concessions.

Table 1: License Ownership Details

Concession	Holder/Co-Holder	Operator	Acreage (km^2)	Award Date	Expiry Date
Cercina Sud	51% ETAP 49% OMV-TP	TPS	16	05/11/2004	04/11/2034
Cercina			144	22/02/1994	21/02/2024
El Hajeb/Guebiba			52	10/06/1983	09/06/2033
Gremda/El Ain			44	01/01/1989	31/12/2018
Rhemoura			36	15/01/1993	14/01/2023

GCA understands that the Tunisian Licensing Authority has informed OMV that it is in the process of preparing a legal study on all the current operating concessions and in priority the concessions that will expire by 2023 including the Gremda/El Ain concession. Based on past experience, GCA considers it reasonable to assume that licenses in Tunisia will be extended provided commercial production remains possible.

Overview

The TPS fields are located near the town of Sfax on the eastern coast of Tunisia. All are onshore except for Cercina/Cercina Sud, which lies offshore in shallow water (2-5 m depth). The productive reservoirs are chalky carbonates at depths between 1,500 and 3,000 m. Production started from the El Hajeb/Guebiba concession in 1983, followed by Gremda/El Ain and Cercina in 1983 and 1994 correspondingly. Production has been by primary depletion except at Guebiba where secondary recovery by means of water-flooding has been successful. Combined daily production from all concessions peaked in 2009 at almost 9,000 bopd, but has since declined to just over 4,000 bopd, mostly from Guebiba and Cercina. Cumulative production from all concessions is 54.0 MMBbl, of which Guebiba and Cercina contribute 19.3 MMBbl and 15.9 MMBbl respectively. The current TPS development plan focuses on drilling new producers targeting upswept oil at these two main fields.

GCA obtained most of the data from the data room set up by OMV specifically for Panoro. These data consist of detailed development studies, comprehensive presentation material on all subsurface disciplines and static reservoir models built by OMV in Petrel.

Good quality 3D seismic and log data are available over El Hajeb/Guebiba and Cercina. A great deal of performance data has been collected since the fields were put on production in the mid-1980s. OMV has performed extensive analysis and modelling work, which GCA has reviewed and generally found to be of good quality.

Reserves Summary

GCA carried out its own decline curve analysis (DCA) to estimate low, best and high profiles for active wells. OMV holds regular Multi-disciplinary Asset Reviews (MAR) with the JV partners to plan future workovers and drilling of new wells at the concessions. The most recent MAR includes a number of such activities agreed by the JV partners, to which GCA has assigned Reserves. Reserves are shown in Table 2.

Table 2: Oil Reserves as at 30th June, 2018 (MMBbl)

Concession	Gross Field			OMV Interest	Net to OMV's Interest		
	Proved	Proved + Probable	Proved + Probable + Possible		Proved	Proved + Probable	Proved + Probable + Possible
Cercina [1,2)]	3.4	7.7	10.0	49%	1.5	3.3	4.3
El Hajeb/Guebiba	5.4	8.6	12.1	49%	2.2	3.6	5.0
Gremda/El Ain [2)]	-	2.1	2.7	49%	-	0.9	1.2
Rhemoura [2)]	0.3	0.7	0.9	49%	0.1	0.3	0.4
Total	**9.0**	**19.0**	**25.8**		**3.8**	**8.1**	**10.9**

Notes:

1. Includes Cercina Sud
2. Proved Reserves are truncated at the current license expiry dates; Probable and Possible Reserves assume the license will be extended under the same fiscal conditions as long as commercial production remains possible.
3. Gross Field Reserves are 100% of the volumes expected to be recovered from the asset under the intended development plan.
4. Reserves Net to OMV's Interest are the working interest fraction of the Gross Field Reserves, less royalty.
5. Totals may not exactly equal the sum of the individual entries due to rounding.

Contingent Resources Summary

Contingent Resources attributed to two potential infill wells in Cercina are shown in Table 3. Further modeling work is required to bring to these opportunities to a higher level of confidence.

Table 3: Oil Contingent Resources as at 30th June, 2018 (MMBbl)

Concession	Gross Field			OMV Interest	Net to OMV's Interest		
	1C	2C	3C		1C	2C	3C
Cercina	1.4	5.0	10.3	49%	0.6	2.1	4.4
Total	**1.4**	**5.0**	**10.3**		**0.6**	**2.1**	**4.4**

Notes:

1. Gross Field Contingent Resources are 100% of the volumes estimated to be recoverable from the project in the event that it goes ahead.
2. Contingent Resources Net to OMV's Interest are the working interest fraction of the gross field Contingent Resources, less royalty.
3. The volumes reported here are "unrisked" in the sense that no adjustment has been made for the risk that the project may not go ahead (i.e. no "Chance of Development" factor has been applied).
4. Contingent Resources should not be aggregated with Reserves because of the different levels of risk involved.

Net Present Value Summary

Reference post-tax Net Present Values (NPVs) have been attributed to each oil production case at the discount rates of 10.0%, as shown in Table 4 and Table 5.

Table 4: Post-Tax NPV (US$ MM) at 10% Discount Rate of Future Cash Flow from Reserves, Net to OMV's Interest, as at 30th June, 2018

Concession	Proved	Proved plus Probable	Proved plus Probable plus Possible
Cercina/Cercina Sud	1.9	38.0	50.7
El Hajeb/Guebiba	22.6	40.6	61.1
Gremda/Al Ain	-	11.6	16.0
Rhemoura	-0.8	1.8	3.6
Total	**23.7**	**92.0**	**131.4**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the assets.
2. All cash flows are discounted on a mid-period basis to 30th June, 2018.
3. The reference NPVs reported here do not represent an opinion as to the market value of a property nor any interest therein.

Table 5: Unrisked Post-Tax NPV (US$ MM) at 10% Discount Rate of Potential Future Cash Flow from Contingent Resources, Net to OMV's Interest, as at 30th June, 2018

Concession	1C	2C	3C
Cercina/Cercina Sud	4.9	22.7	39.5

Notes:

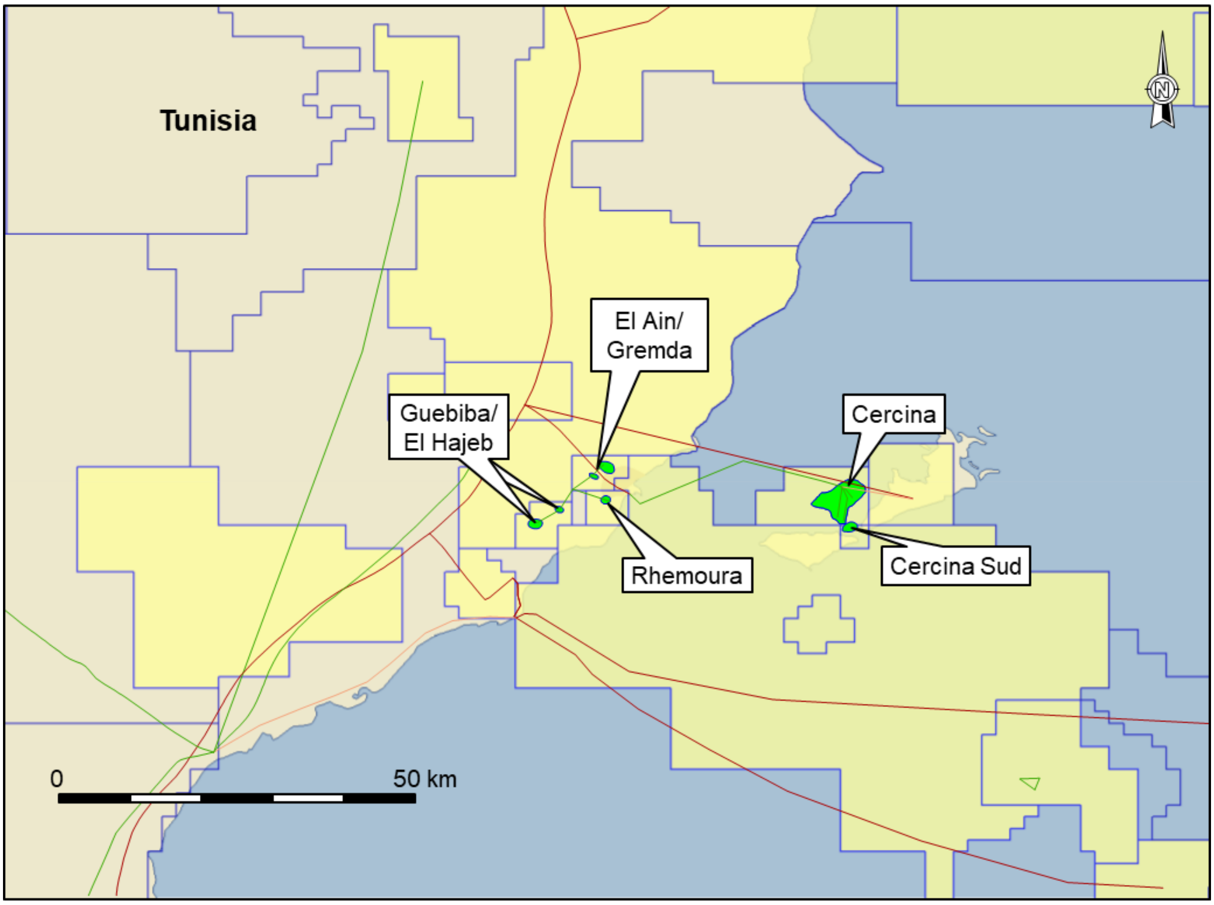
1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. All cash flows are discounted on a mid-period basis to 30th June, 2018.
3. The NPVs reported here are "unrisked" in the sense that no adjustment has been made for the risk that the developments may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor, as defined under PRMS, has been applied).
4. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

Discussion

1 Background

The TPS assets are located onshore and in shallow water offshore in close proximity to the town of Sfax on the western coast of Tunisia (Figure 1). The onshore concessions include Rhemoura, El Ain/Gremda and El Hajeb/Guebiba. The two offshore concessions are Cercina and Cercina Sud.

Figure 1: TPS Assets Location

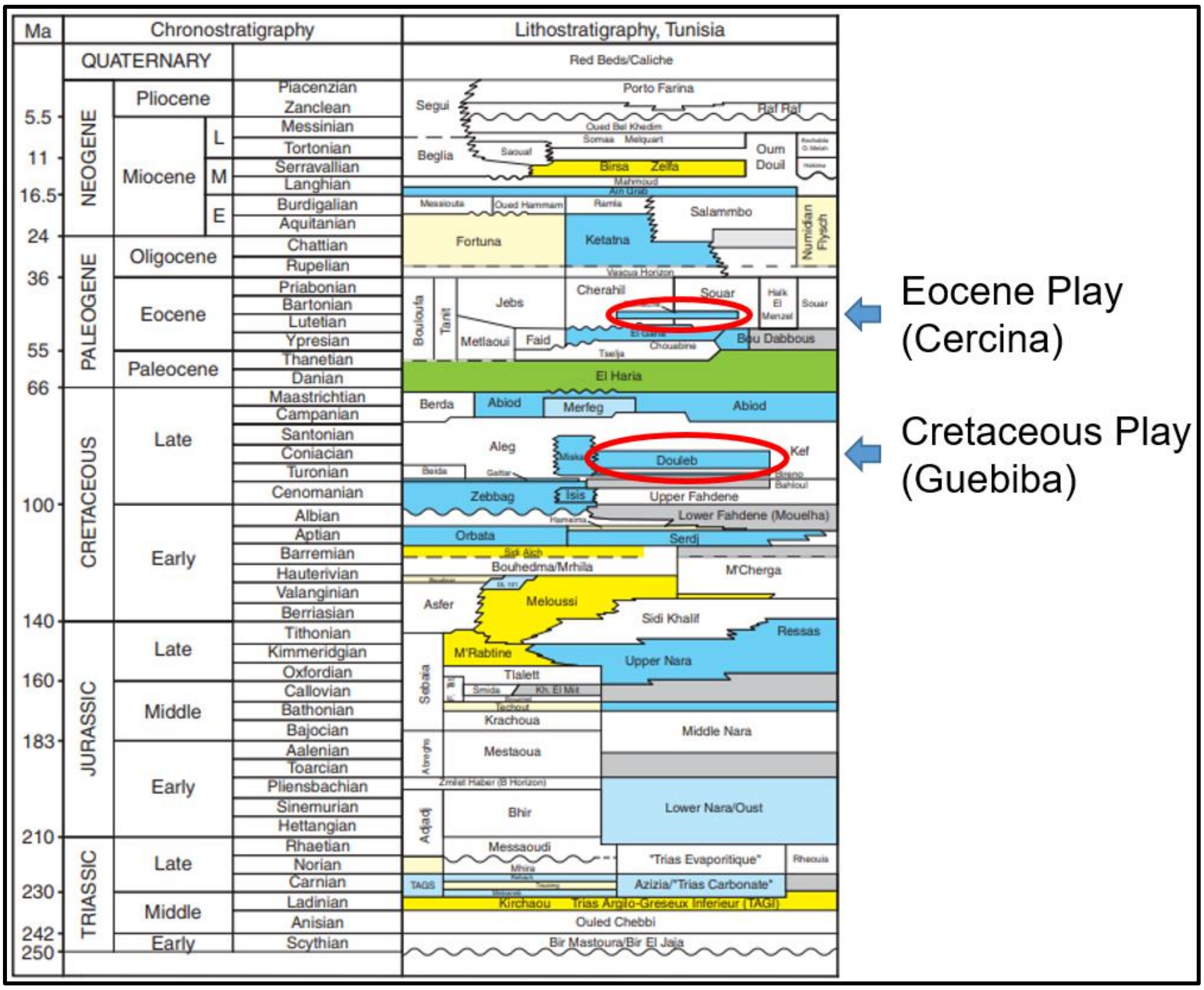


Source: Petroview

1.1 Geological Overview

The TPS assets lie in the Pelagian sedimentary basin, immediately to the south of the Atlas Mountain Trend and include carbonate reservoir units of Cretaceous and Eocene age (Figure 2).

Figure 2: Stratigraphic Column for Tunisia



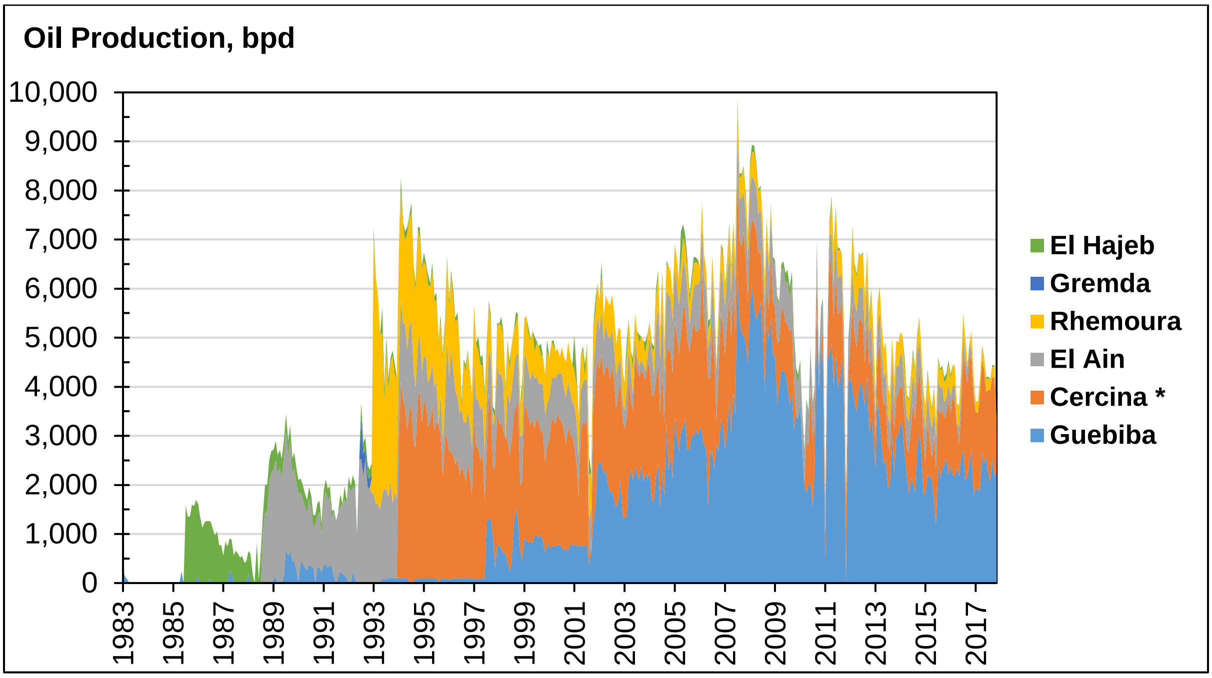
Source: USGS Klett, 2001

2D seismic is available for Rhemora, Cercina Sud, and Gremda/El Ain. Other fields are covered by good quality 3D seismic. Structural work performed by OMV suggests that reservoirs are highly compartmentalised. The primary reservoirs are the Cretaceous Douleb and Bireno (present in most of the onshore fields) and the Eocene Reineche (present in Cercina). The reservoirs are generally of a good quality with porosity and permeability ranges of 18-23% and 17-100 md respectively.

1.2 History

Production began onshore in the late 1980's and offshore in 1994. The initial production method was through natural depletion drive as most fields benefit from having various degrees of aquifer support. Water injection began in 2005 with a dumpflood into the Douleb reservoir in Guebiba. The two largest fields by cumulative oil production are Guebiba and Cercina. Gross (100%) production from the assets is shown in Figure 3.

Figure 3: TPS Fields Production Performance



* Includes Cercina Sud

The current well stock comprises 48 development wells that have been active in the field over the historical period. Around 65% of those were completed in the Guebiba and Cercina fields, the total well counts for TPS fields are shown in Table 6.

Table 6: Well Stock and Production Data, TPS Fields

TPS	Producers Well Count			Cumulative Production			Average Rates in 2018 1)		
Field	Active wells	Inactive wells	Total wells	Oil MMBbl	Gas Bcf	Water MMBbl	Oil bopd	Gas Mscfd	Water bwpd
Cercina	7	12	19	15.9	6.7	23.0	1,708	681.0	4,521
Guebiba	4	8	12	19.3	2.4	9.5	2,206	84.5	2,816
El Hajeb 2)	2	9	11	2.1	0.8	8.3	31	-	1,474
Rhemoura	1	4	5	6.6	3.1	12.4	208	0.2	1,218
El Ain	0	6	6	10.1	7.9	20.7	-	-	-
Total	**14**	**39**	**53**	**54.0**	**20.8**	**73.9**	**4,153**	**765.7**	**10,029**

Source: OMV Production Database, as of 30th June 2018

Notes:

1. First 6 months of 2018.
2. Gas production for El Hajeb is not reported.

The initial reservoir pressure increases from 2,389 psi in the shallowest Lower Reineche reservoir at Cercina to 2,830 psi for the deepest Douleb zone at Guebiba. The reservoir temperature increases from around 80°C up to 135°C (Table 7).

Table 7: TPS Fields PVT Properties

Field	Reservoir	Depth mTVDss	T ini ºC	P ini psia	P sat psi	Bo rb/stb	GOR scf/stb	Viscosity cp	S.G. oil ºAPI
Cercina	Lower Reineche	1,450	80	2,389	1,175	1.13	176	2.9	28
Guebiba	Douleb	2,850	135	4,177	500	1.12	76	0.7	34
	Bireno	2,850	137	4,081	622	1.12	89	0.6	34
El Hajeb	El Gueria	2,120	107	3,271	675	1.14	110	1.8	29
Rhemoura	Bireno	2,700	135	3,953	1,575	1.34	389	0.6	34
El Ain	Bireno	2,610	101	3,855	2,880	1.5	704	0.4	39

The produced oil is a light crude with gravity varying from 28 to 39 ^{0}API. Oil is under-saturated in all formations without any gas caps. Solution gas-oil ratio (SGOR) ranges between 76 and 704 scf/stb with the highest value at El Ain. In-situ oil viscosity is low – in the range of 0.4 to 2.9 cp – and correlates with API.

The TPS facilities and infrastructure network is optimized to handle sour and light oil, gas and produced water. The facilities currently have capacity to process an average oil production of 6,000 bpd, 12, 000 bpd of water and 1.8 MMscfd of gas. The fields are linked to 4 processing facilities: Cercina Platform, the Tank Battery, Guebiba Pump Station and Rhemoura. The processed crude is then transported to the La Skhira oil storage and export terminal.

2 Cercina

The Cercina field is located in the Gulf of Gabes, 25 km offshore from the city of Sfax. It lies just off the northwestern side of the Kerkennah Islands in water depths ranging from 2 to 5 m.

2.1 Introduction

The Cercina oilfield was discovered by the British Gas well Kerkennah - North (KKN-1) in 1991. KKN-1, subsequently renamed to CER01, successfully tested the Tertiary Lower Reineche Formation. Eleven (11) wells were drilled in 1991-1993, with an initial production rate of around 3,500 bopd, with three further wells (CER13/CERSTH1A/CER15) drilled in 2002-03. Wells commingle production from both the Upper and the Lower Reineche layers in the western part of the field, but the Upper Reineche pinches out on the eastern side of the field. Both Upper and Lower Reneich formations are thin and friable nummulitic carbonate with high permeability streaks.

2.2 Geology

The structure of the Cercina field but also the wider area was formed by varying compressional and extensional tectonic events. The observed compressional structures like anticlines, synclines, domal features, and local lows, all of them with comparatively low relief, are repeatedly found in the Cercina-Chergui area. They were formed by Alpine orogenic movements in Late Eocene to Oligocene times. During the Late Miocene extensional movements took place and had a significant impact on the general structure. The anticlinal and domal structures were modified by wench and reverse faults providing combined traps in which the hydrocarbons accumulated.

The area is dominated by NW-SE and, to a minor degree, by NE-SW striking normal faults with the NE-SW fault trend seemingly older. Fault throw is reportedly moderate and reaches a maximum of 80 m. However, the faults may offset the relatively thin Reineche intervals that reach individual thicknesses of maximum 18 m. Especially for the NE-SW trending faults a general sealing capacity has been interpreted by the operator leading to a complex compartmentalization of the field.

The Reineche Member of Lutetian-Bartonian (Eocene) age is the main reservoir. It is subdivided into:

- Lower Reineche Argillaceous Limestone unit (generally tight and considered to be non-reservoir);
- Lower Reineche (forms the main reservoir) has a thickness of 10 to 12 m, average porosity between 17% and 21% and average permeability between 0.01 and 60 mD. The reservoir appears to be fractured which enhances production considerably in the two best wells of the field (CER02 and CER03);
- Middle Reineche (tight, non-reservoir); and
- Upper Reineche limestones are subdivided into several units displaying in general poorer reservoir properties. It pinches out towards the NE of Cercina where the thickness reduces from 15 m in CER11 to 1 m in CER05. This pinch out may reflect a phase of erosion which is consistent with the presence of a broad regional high (Kerkennah Arch) northeast of the Cercina Field.

The field was sourced by the Bou Dabbous formation of lower Eocene age containing kerogen type I&II with a TOC of up to 8%. Sealing formation is provided by the lower Eocene Souar mudstone. Migration occurred laterally into adjacent juxtaposed reservoirs and vertically along faults and fractures.

2.3 Seismic Interpretation and Static Model

A 3D shallow seismic acquisition survey (132 km²) was recorded by CGG Veritas in 2007 and was processed during 2007-2008 with the objective to maximize the resolution and to enable detailed structural and stratigraphic interpretation. The interpretation resulted in the first robust static model in 2009 and an update in 2011.

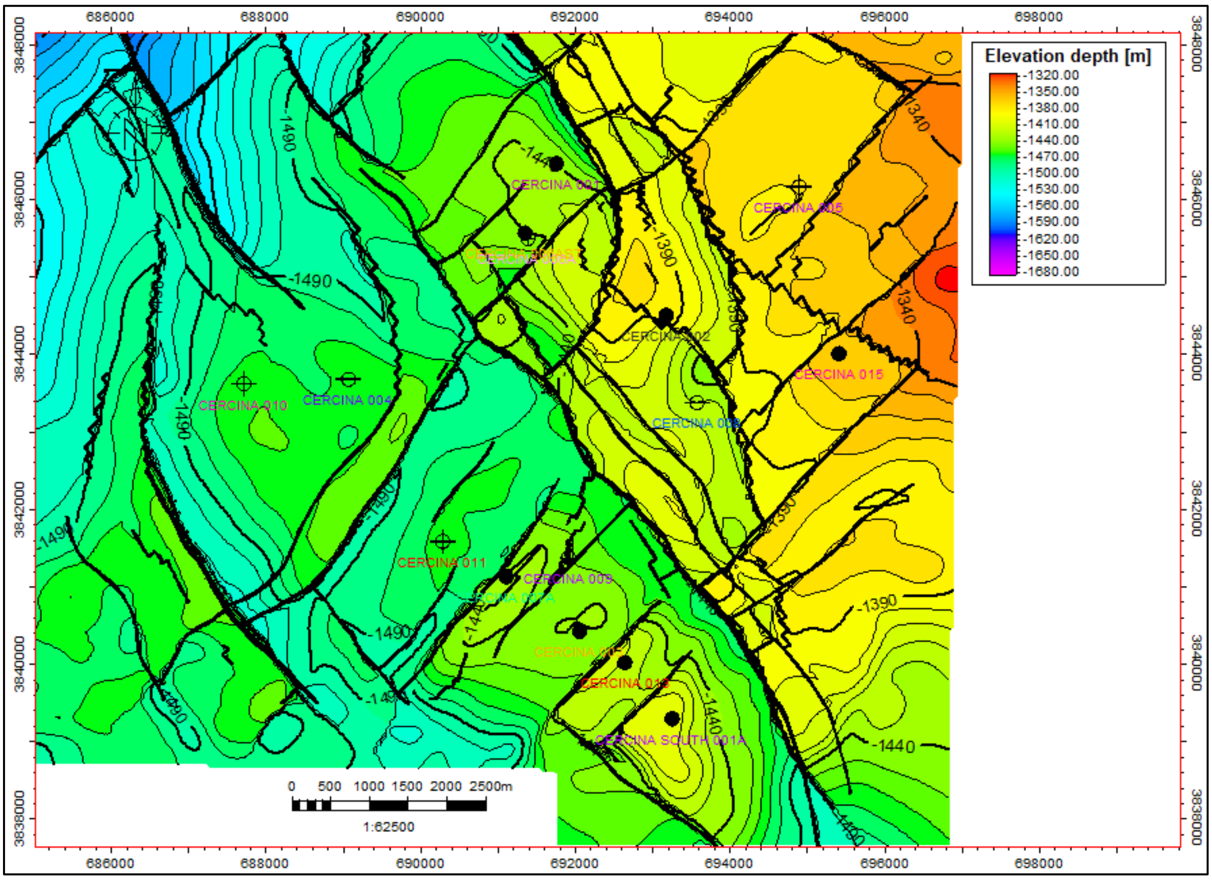
In 2015, a new structural and seismic study was performed by the operator including a seismic attribute analysis and an inversion feasibility study. An updated velocity model improved the top Lower Reineche structural depth map. Seismic attributes were generated for structural analysis: variance, polar dip plus Ant Track tracking. They were used to confirm the existing fault pattern. Waveform classification was carried out resulting in enhanced stratigraphic and reservoir architecture interpretation (limit of erosion and clinoforms). In addition, amplitude and impedance were analyzed in order to improve reservoir property distribution (Facies) in the static model.

The seismic and static Petrel projects containing the latest interpretation and model were provided by OMV and screened by GCA for any obvious flaws. Based on the provided high quality reports and the comparison of past and present top reservoir depth structure maps, GCA concluded that the technical work was very reasonable and complied with good industry practice.

The seismic interpretation was not adjusted between the 2011 and 2015 interpretation campaigns indicating the robustness of seismic definition. The fault pattern was further enhanced by the application of the Ant-Track automated fault picking largely confirming the previous interpretation.

Cercina Field is compartmentalized with each compartment filled to various levels. No definitive OWC could be defined for the whole field. Various sets of contacts were estimated and used for static model runs. The ODT levels range from -1,369 mTVDss (CER15) to -1,453 mTVDss (CER01). The provided static model honors the contacts as encountered by wells in respective fault compartments. Fault surfaces are defined and used to divide the field into a total of 24 fault blocks (segments). In addition, 7 layers (zones) are defined. Each fault block was modelled honoring the respective well results (Figure 4). A north-south cross-section form the Cercina static model is shown in Figure 5.

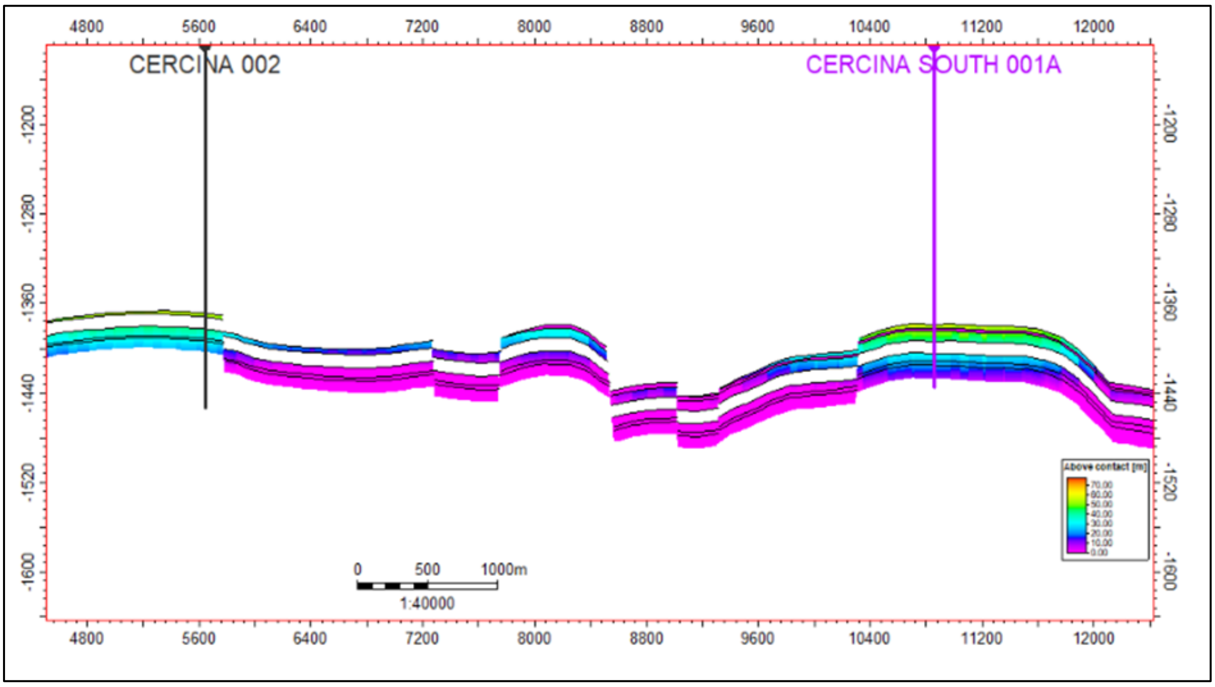
Figure 4: Lower Reineche Reservoir Top Structure Map, Cercina Field



Source: OMV Static Model

In order to populate the model with reservoir properties several facies models were generated: regional depositional trend, wave classification and amplitudes attributes. A third party (Apex) sedimentary study (2010), well reports, core photos and thin sections, conceptual models, wireline logs and seismic attributes are the main basis for input. Diagenetic and depositional control on reservoir quality were also considered. Overall, six porosity models have been generated, three using co-kriging with a facies transformation function and adjusted variogram plus three with pre-stack /post-stack seismic inversion.

Figure 5: Cercina OMV Static Model North to South Cross-Section



While the best porosity is seen in the Lower Reineche 1.2 and Lower Reineche 3 zones with values up to 38%, average porosity was estimated to be approximately 11% within reservoir quality rocks and 9% over the whole gross rock volume (GRV) including non-reservoir. Permeability is derived from core porosity-permeability relationships generated for each facies in the Apex study.

2.4 STOIIP Estimation

OMV provided a static model which relates to a base case overall STOIIP volume for the total field, which was confirmed by screening all other available and reported volumes by the operator (Table 8).

Table 8: Cercina Legacy STOIIP Estimates by OMV

Parameter	Units	2015 Porosity Amplitude	2015 Porosity Vp/Vs	Petrel Model June 2018	2015 Porosity-wave	2015 Porosity Shear Impendance
GRV	MMm^3	1,206.0	1,206.0	1,206.0	1,257.6	1,257.6
GRV	M(acre*ft)	978.0	978.0	978.0	1,019.6	1,016.6
NTG	%	100.0	100.0	100.0	100.0	100.0
Porosity	%	9.6	9.8	9.6	9.7	10.1
So	%	29.4	29.0	35.8	35.8	35.8
FVF	scf/rb	1.2	1.2	1.2	1.2	1.2
STOIIP	MMBbl	185.0	186.6	225.3	236.9	246.4

While STOIIP for the whole field may give an indication of the potential for further development in the future, the immediate field development plan focuses on the drilled segments only. GCA made its own estimates of STOIIP for these segments based on the OMV static model, as shown in Table 9. While the Low Case estimate is related to area of the block times average thickness estimates above a “low” OWC at -1,454 mTVDss, the High Case is based on area times average thickness above -1,467mTVDss for each segment. Average porosities and oil saturations were also varied. The Best Case is set to be the average of the Low and High cases.

Table 9: Cercina Static Model STOIIP Estimates by Individual Segment

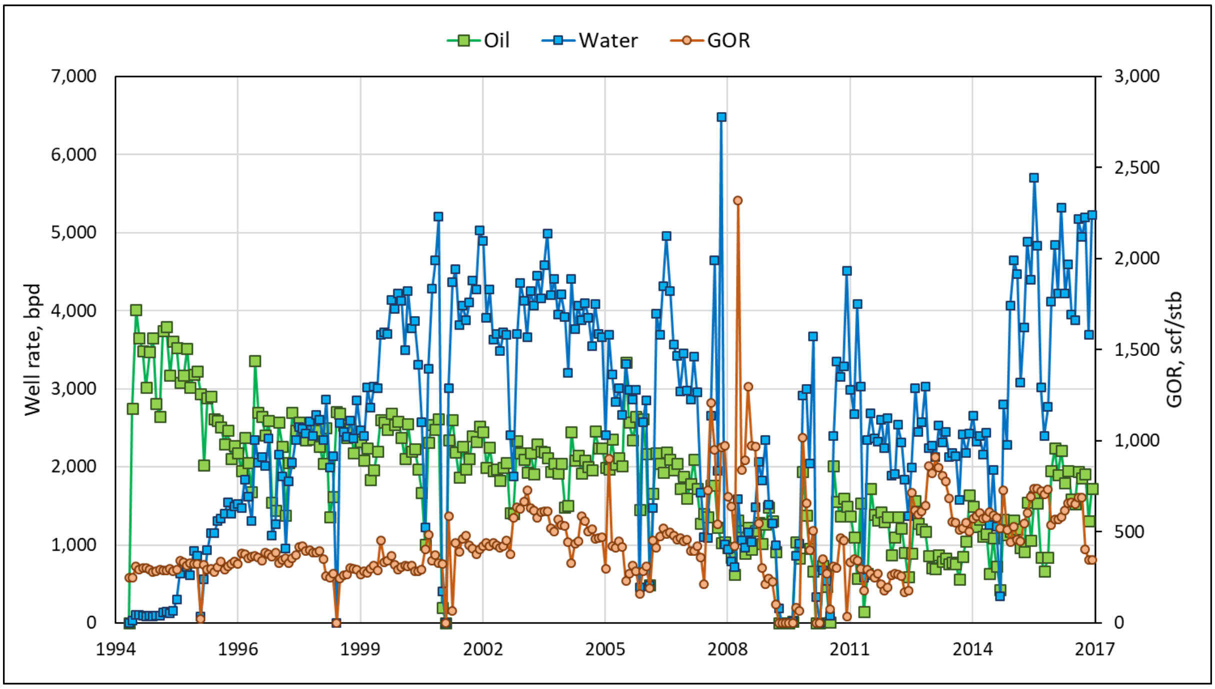
Static Model Segments*	STOIIP, MMBbl		
	Low	Best	High
Segment 7 (CER04, CER10)	8.1	22.8	37.4
Segment 8 (CER6ST, CER01)	12.2	14.4	16.6
Segment CER15	5.3	5.8	6.3
Segment 12 (CER02)	0.1	0.1	0.2
Segment 3 SE	5.3	5.8	6.4
Segment 12 (CER08)	5.0	5.5	5.6
Segment 9 W	12.5	13.7	14.9
Segment 10 (CER03, CER07, CER09)	2.5	6.5	10.5
Segment 15 (CER08)	10.2	11.2	12.2
Segment 16 (CER02)	18.7	20.5	22.4
Segment 17 N	6.6	7.0	7.4
Segment 18 (CER05)	0.2	0.2	0.2
Segment 1 Central	15.4	17.0	18.6
Segment (CER08 EXT1)	2.0	2.2	2.3
Segment (CER03,CER07, CER09)	0.0	1.5	2.9
Segment 3 (CER11)	0.0	0.0	0.0
Segment SE	12.8	13.6	14.4
Segment CERS1A	15.7	19.1	22.4
Segment CER13	10.3	12.2	14.0
Segment 7 (CER03, CER07, CER09)	10.0	12.6	15.3
Segment (CER09)	0.1	0.4	0.7
Segment 1	8.2	9.3	10.5
Segment 8	0.0	0.0	0.0
Total	**161.0**	**201.2**	**241.0**

* Nomenclature as per the OMV static model

2.5 Historical Performance

Wells at Cercina field produce from the Upper and Lower Reineche reservoirs. The Lower Reineche is volumetrically more significant and has better reservoir quality than the Upper Reineche, which pinches out on the eastern side of the field. Cercina historical production is shown in Figure 6. Most of the oil recovery comes from two wells – CER02 and CER03. These wells penetrated fractured zones and have produced 7.8 MMBbl and 4.8 MMBbl of oil respectively (79% of the total field production).

Figure 6: Cercina Historical Performance



Source: OMV Production Database

In 2015 OMV built a static model for Cercina, which was brought to dynamic simulation in 2017. OMV achieved a reasonable history match on the production rates. In contrast, the match on pressures for most wells is poor. OMV explained this by issues with production allocation: some of the wells are completed across both the Upper and Lower Reineche and such wells do not have any PLTs to perform a split of individual reservoirs contributions. To adjust flow between the various reservoir zones, OMV has used skin factors as high as +72.5. Given the history match uncertainties and production allocation issues, GCA did not use the dynamic modelling results to estimate the future field performance.

2.6 Development Plans

GCA reviewed future drilling opportunities that OMV included in the work program. Locations for three new wells are shown in Figure 7. Only well CER18 will be placed in an undrilled reservoir compartment; other two wells represent replacements of existing wells with casing integrity problems.

GCA estimated future performance of the active and planned production wells using DCA and the results of material balance modelling performed by OMV. Estimated ultimate recovery (EUR) by reservoir compartment are tabulated in Table 10.

Figure 7: Lower Reineche Pressure Map with Proposed Wells

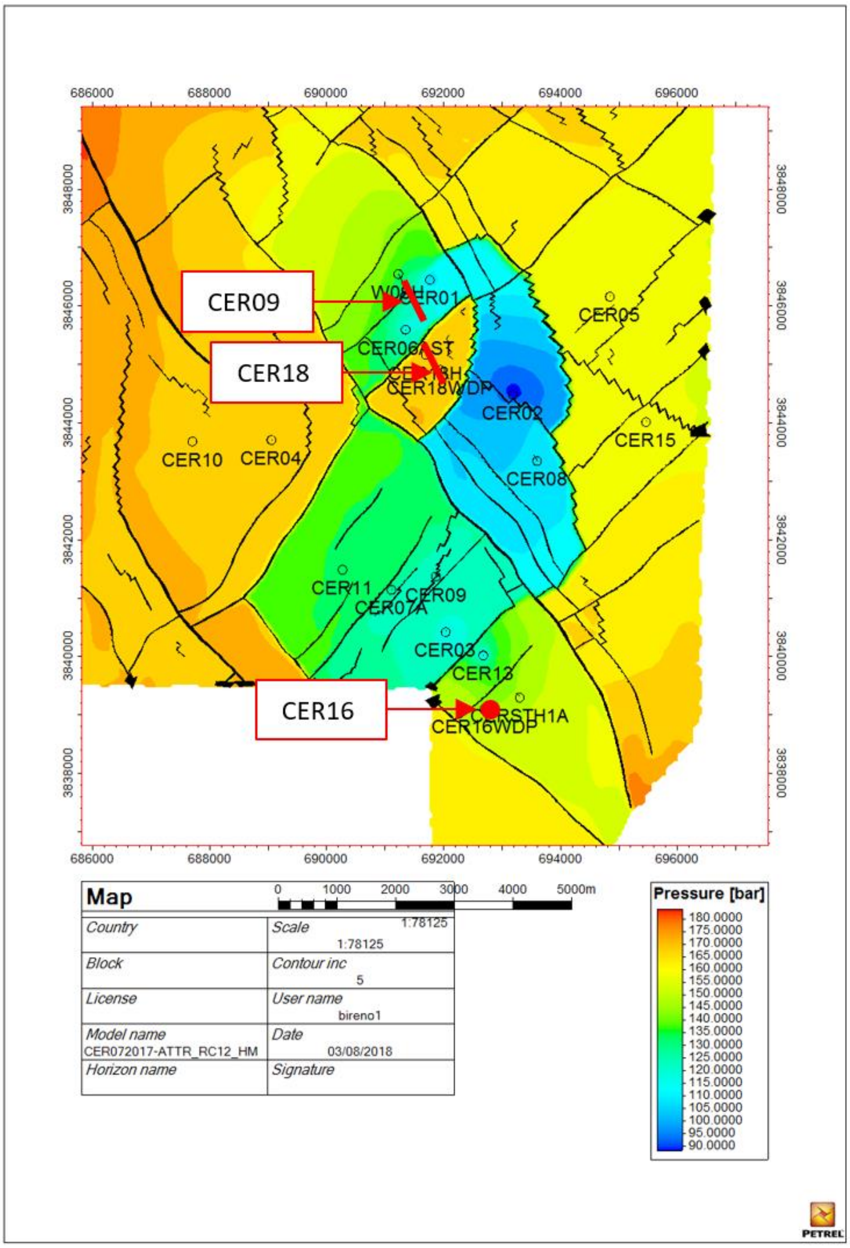


Table 10: Oil Recovery by Reservoir Compartment

Segment	Low Case		Best Case		High Case	
	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl
Segment CER01-06AST	12.23	2.16	14.42	2.29	16.62	3.28
Segment CER02	28.86	9.63	31.70	9.94	34.56	10.20
Segment CER03	18.31	5.82	22.34	5.99	26.37	6.12
Segment CER13	10.34	0.87	12.15	0.96	13.96	1.08
Segment CERSTH1A	15.74	2.72	19.09	3.78	22.43	4.13
SegmentCER15	5.26	0.05	5.78	0.25	6.30	0.44
Total	**90.74**	**21.25**	**105.48**	**23.20**	**120.24**	**25.26**

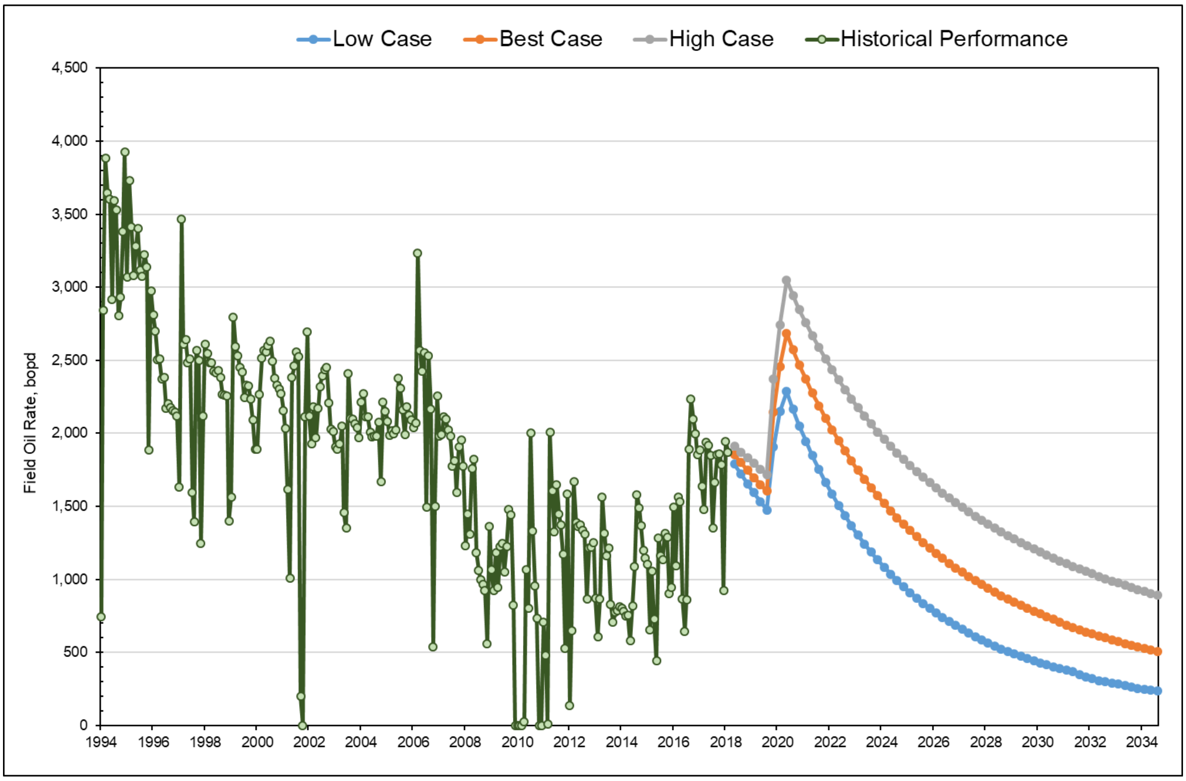
Notes:

1. EUR represents an estimate of technically recoverable volumes with no consideration of economics, and includes volumes already produced; it does not equate to Reserves.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

2.7 Reserves

Reserves were assigned to seven active producers and to one workover in well CER15. GCA also included planned producers CER09 and CER16 in the reserves profiles. Well CER18 was not included as its target reservoir segment has not been penetrated by any of the wells. Cercina production profiles are shown in Figure 8.

Figure 8: Cercina Oil Production Forecast



2.8 Contingent Resources

Following OMV's preliminary material balance modelling work, Contingent Resources were assigned to new wells in Segment 7 (CER04, CER10), where potentially unswept oil volumes exist. Further modeling work is required to bring to these opportunities to a higher level of confidence.

No other Contingent Resources are assigned at this time.

3 Guebiba

The Guebiba Field is located onshore approximately 18 km to the west of Sfax city, in the eastern part of the Gulf of Gabes basin.

3.1 Introduction

The Guebiba Field was discovered by Houston Oil and Minerals in 1981. Tenneco, British Gas and Preussag have since held the field through takeovers and asset disposals. Production started in August, 1983, however at a low level. A 3D seismic survey covering 57 km^2 was acquired in April, 2000.

3.2 Geology

The structure of the Guebiba Field was formed by a combination of older compressional and younger extensional movements. These movements created a mild anticlinal structure which thereafter was limited by extensional faulting and compartmentalized by smaller faults. The fault limiting the domal structure is a predominantly NNW-SSE trending fault system with mostly parallel fault geometry. There are several truncations between faults and substantial throws of the boundary faults. These major faults show some elements of mild strike-slip movement. The throw varies from 430 m to 540 m (Western Boundary Fault) and 270 m to 460 m (Eastern Boundary Fault), while the normal faults within the field area are substantially smaller with throw between less than 10 m and 40 m. The comparatively large throw is reached by the fault that limits the highest area of the field (Guebiba-10a) to the west.

The combination of the faulting with a strongly layered reservoir leads to a very complex three dimensional reservoir model.

Two reservoirs are forming the Guebiba accumulation.

- The Douleb Member consists of a fractured oolithic grainstone to wackestone with pelloidal and fossil debris of Turonian to Coniacian age. Oolithic and oo-bioclastic facies offer the best reservoir potential with intergranular and rare vuggy porosity of up to 25%. The formation exhibits permeability of up to 170 mD (Gue-2 well). Average thickness of net reservoir in the Guebiba field is 10-12 m. Initial water saturation averages 26%. The Douleb was cored in, Gue-3, Gre-1, Gre-2
- The Bireno fractured limestone of Turonian age consisting of wackestone to packstones, intercalated bioclastic rudstones, with some presence of stylolites and in the lower part, some dolomites and tight anhydrite beds. Porosity types include intercrystalline matrix microporosity, microvuggy to vuggy porosity, intergranular and intraparticle porosity. Some open fractures contribute to the pore space.

Hydrocarbons originate mainly from the Cretaceous Bahloul Formation source rocks. This is a carbonate formation of Cenomanian age and is underlying the reservoirs of the Guebiba

Field. The Bahloul is a type II kerogen source rock with TOC of 4-6% by weight. To a minor extent, source rocks of the Eocene Bou Dabbous Formation may have contributed.

The top seal for the Douleb reservoir is provided by tight shales and shaly limestones of the Aleg Formation. The top seal for the Bireno reservoir is provided by the Aleg Inferior (part of the Aleg Formation) and shales and shaly limestones of the Upper Peritidal Facies of the Bireno. Furthermore, tight shaly dolomites and limestones and thin anhydrite layers provide effective intraformational seals within the Bireno reservoir.

Migration pathways for the expelled hydrocarbons were provided by the regional fault system, fractures and permeable layers. The OWC in the Douleb reservoir was not penetrated by the existing wells. OMV uses a single OWC for both reservoirs, which was set at -2,901 mTVDss.

3.3 Seismic Interpretation and Static Model

The Guebiba 3D seismic (58 km^2) was acquired in 2000 by CGG Veritas and the El Hajeb 3D (35 km^2) was acquired in 2004. The two surveys were merged and reprocessed in 2005 by Spectrum with particular focus on optimisation of structural features (especially fault delineation). Spectrum achieved some significant improvements to the structural imaging and fault definition using refraction statics and PSTM processing.

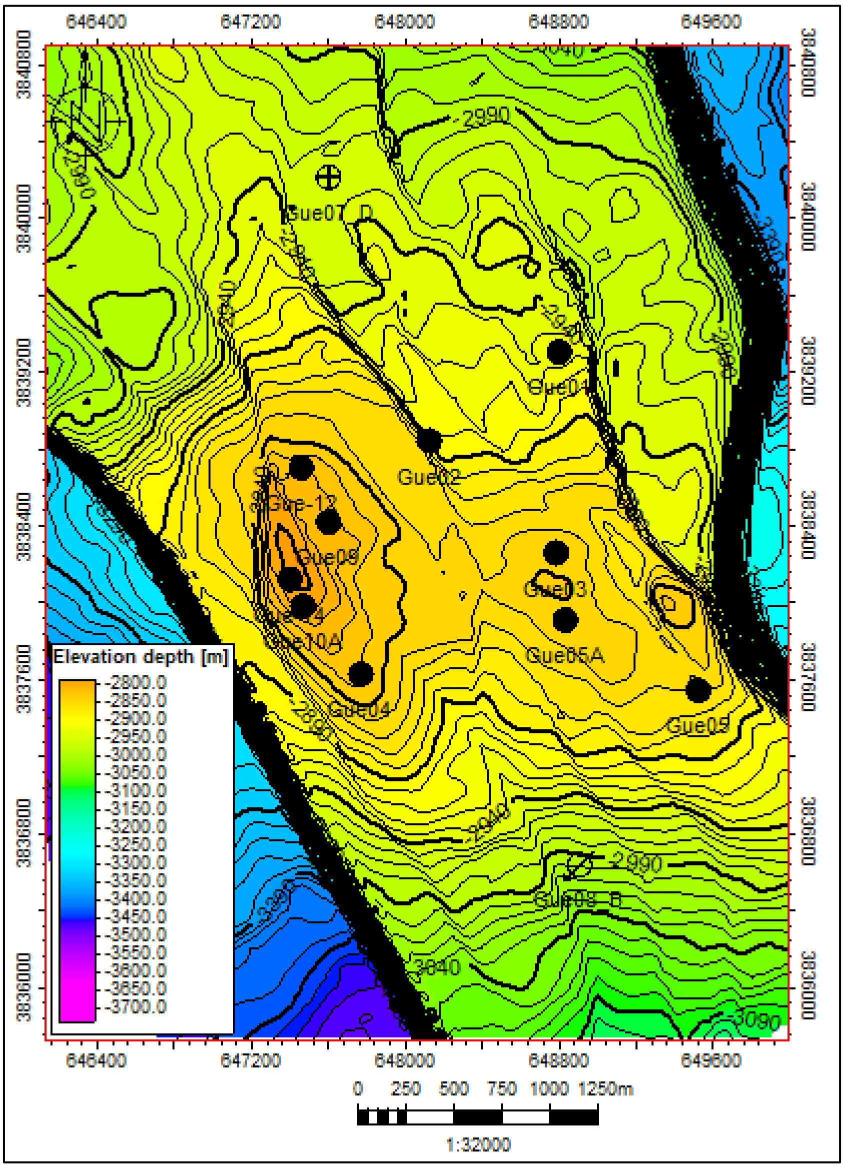
A first interpretation of the reprocessed seismic was carried out during the first quarter of 2006, followed by a re-interpretation with incorporated new well data in 2007. The static model was built in 2015 after drilling wells GUE12 and GUE14. This static model is underlying the latest production profiles and was made available by OMV.

Structural uncertainties were recognised and two different scenarios proposed by the Operator based on different time depth conversion scenarios and fault interpretation. It was assumed that juxtaposition of different sediments displaying different velocities could have led to local pull-ups below the main faults. These could have been mis-interpreted as minor fault–limited horst features. Top reservoir structure maps for Bireno and Douleb are shown in Figure 9 and Figure 10 respectively.

The seismic interpretation was audited by GCA and the above-mentioned findings by the Operator are found to be reasonable. Overall the main seismic reflectors picked are of prominent character and the structure defined as a prominent faulted high is well defined. While towards the NE and SW clear fault cuts are limiting the accumulation, the structural dip towards the NW and SE has some uncertainty related to time/depth conversion. Towards the SE, the structure is better defined by wells, but the NW limit is more uncertain. The effect of local pull-up below the main bounding faults is visible. This will have some effect on the local internal structuration of the field, but it is unlikely that the overall in place volumes would be significantly affected.

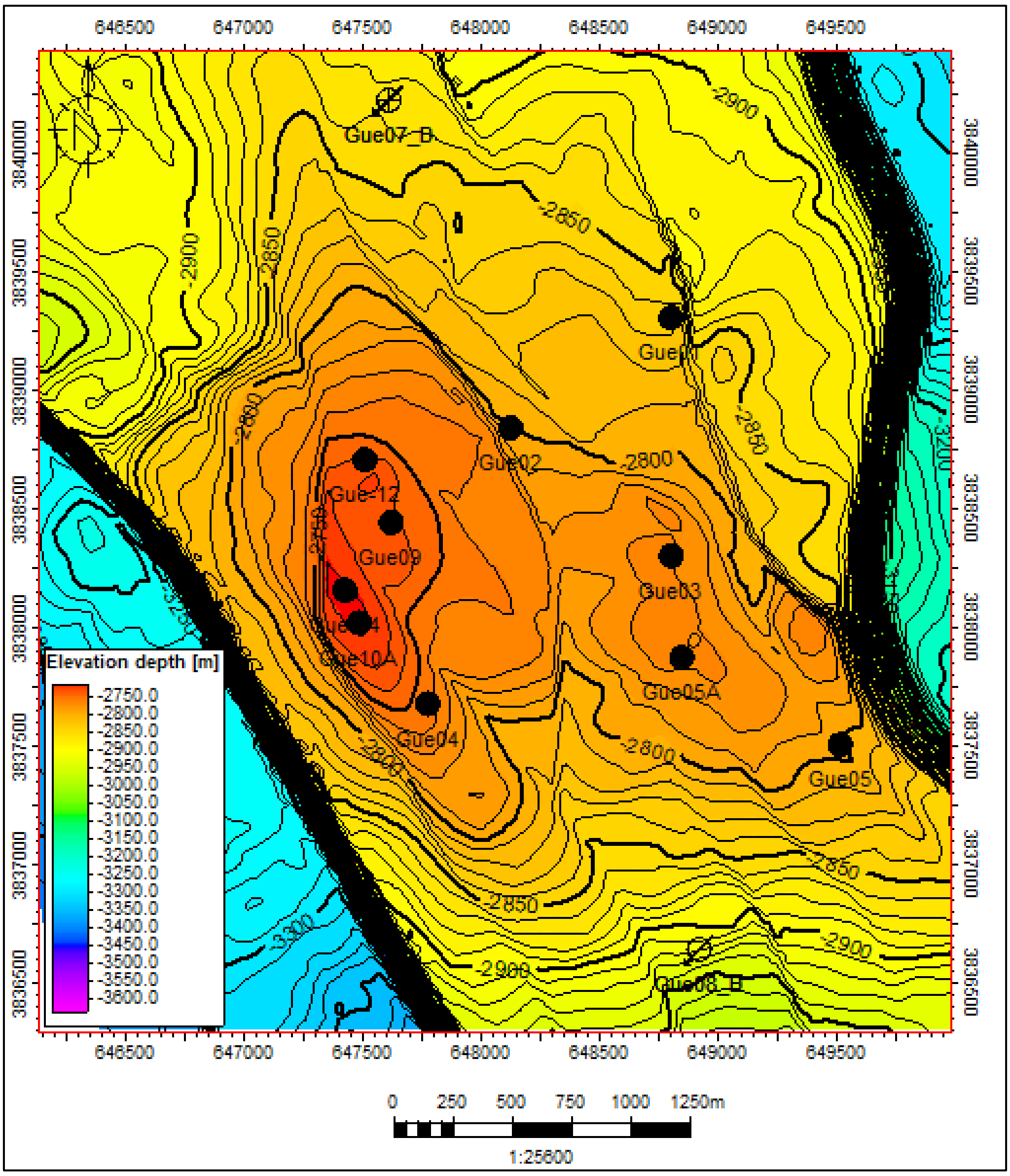
While the upper Douleb reservoir member is a thin continuous reservoir layer averaging approximately 11 m in thickness, the deeper Bireno reservoir is thicker than the hydrocarbon column. This reservoir is more sensitive to any time/depth conversion uncertainty. Figure 11 shows cross-sections through the Guebiba Field highlighting the distribution of porosity and hydrocarbon saturation.

Figure 9: Bireno Reservoir Top Structure Map, Guebiba Field



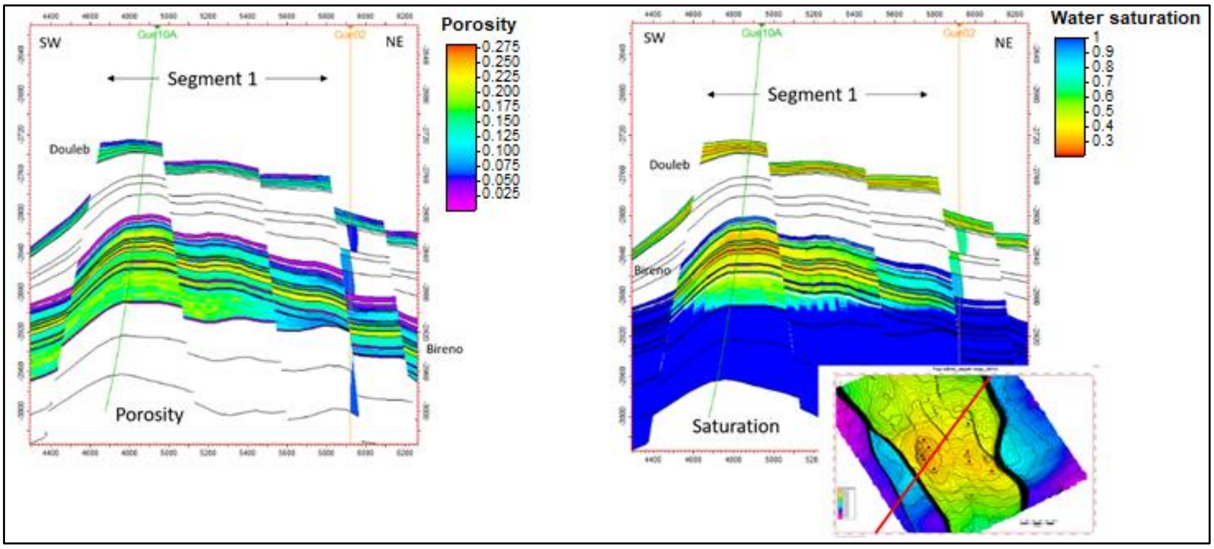
Source: OMV Static Model

Figure 10: Douleb Reservoir Top Structure Map, Guebiba Field



Source: OMV Static Model

Figure 11: Cross-section Through Guebiba Field Showing Porosity and Saturation Properties



Source: OMV Static Model

After the static model audit was performed, GCA concluded that it complies with good industry practice.

3.4 STOIIP Estimation

GCA defined the Low Case using a shallower OWC at -2,872 mTVDss based on the ODT in well GUE12. The High Case is derived using a deeper contact of -2,901 and the Best Case was taken as a mid-point between the two. Reservoir properties and top structure surfaces were also varied across GCA cases. Estimates were performed by modifying the OMV static model (Table 11).

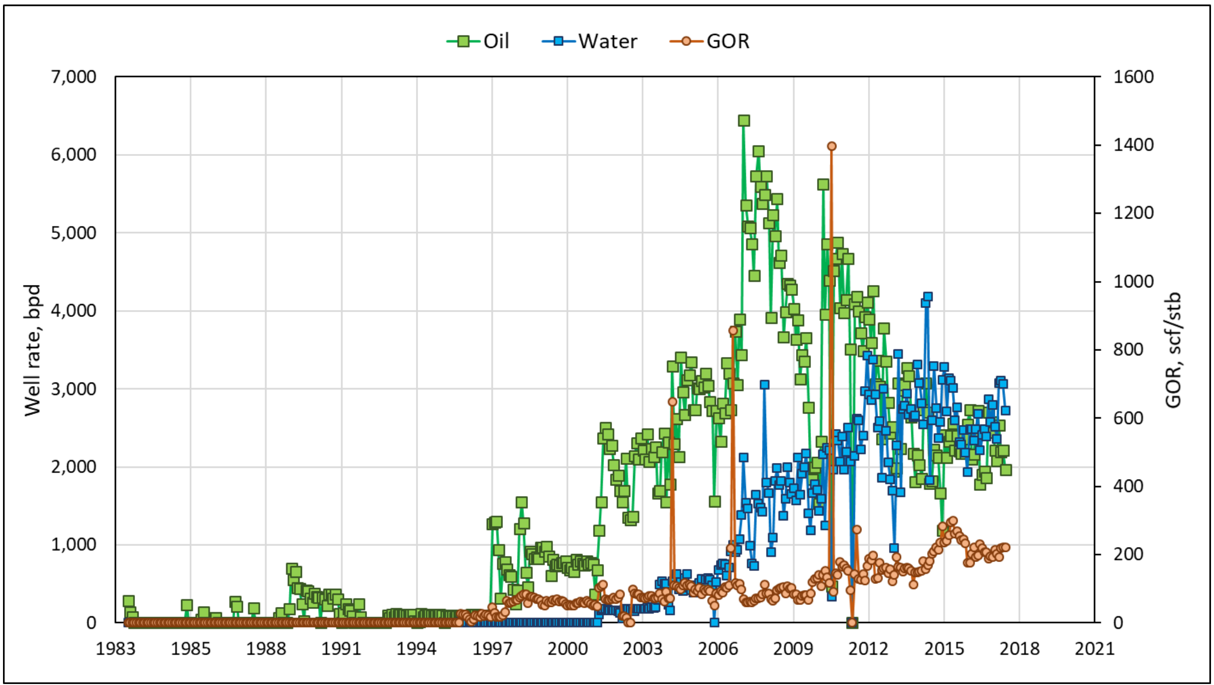
Table 11: Guebiba STOIIP Estimates (MMBbl)

Reservoir	Low	Best	High
Douleb	19.2	24.3	29.4
Bireno	22.2	38.7	55.2
Total	**41.5**	**63.0**	**84.6**

3.5 Historical Performance

Geubiba field comprises two reservoir zones that are currently under development. The Douleb reservoir is of a good reservoir quality with permeability reaching as high as 170 mD. The Bireno reservoir is highly faulted and has non-reservoir anhydrite intercalations that split it into multi-layered system. Water injection was introduced in the Douleb reservoir after its pressure declined down to 600 psi. Injector CER08 demonstrated good communications with producers and helped to improve the reservoir pressure and sweep efficiency. The Guebiba field performance is shown in Figure 12.

Figure 12: Guebiba Historical Performance



OMV used the Guebiba performance history to build material balance models. GCA considers that the history match achieved in the models for both reservoirs is reasonable and provides a solid guidance for the connected fluid in-place volumes.

The dynamically derived volumes for the Bireno reservoir and the field as a whole exceed those estimated in the static model. If the range of STOIIP from the static model is used, the recovery factor in the Bireno reservoirs would be exceptionally high by comparison with recoveries seen at analogue fields. Given the Guebiba long-term production history, GCA has used STOIIP estimates from the detailed material balance studies by OMV (Table 12).

3.6 Development Plans

Further development plans include drilling a side-track of GUE10A along with performing workovers (WO) to reactivate currently suspended wells. GCA reviewed the substantial amount of work performed by OMV and partners for de-risking the GUE10A side-track and considers the proposed well location to be reasonable as it will be completed in a known Bireno reservoir compartment that remains underdeveloped. OMV also presented a study on introducing water injection in the Bireno reservoir. For this purpose well GUE07 will be converted to an injector. The study uses Douleb reservoir as an analogue, where 1,000 bopd production increase in producer GUE02 was seen after water injection started.

GCA evaluated performance of the active and planned producers using DCA. The range of benefits due to water injection in Bireno was estimated using OMV dynamic model. Resulting EURs by reservoir are tabulated in Table 12.

Table 12: Guebiba STOIIP and Oil Recovery by Reservoir

Reservoir	Low Case		Best Case		High Case	
	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl
Douleb	18.0	8.6	21.2	9.2	25.2	9.7
Bireno	54.5	16.8	57.1	19.2	61.0	21.6
Total	**72.5**	**25.5**	**78.3**	**28.3**	**86.2**	**31.3**

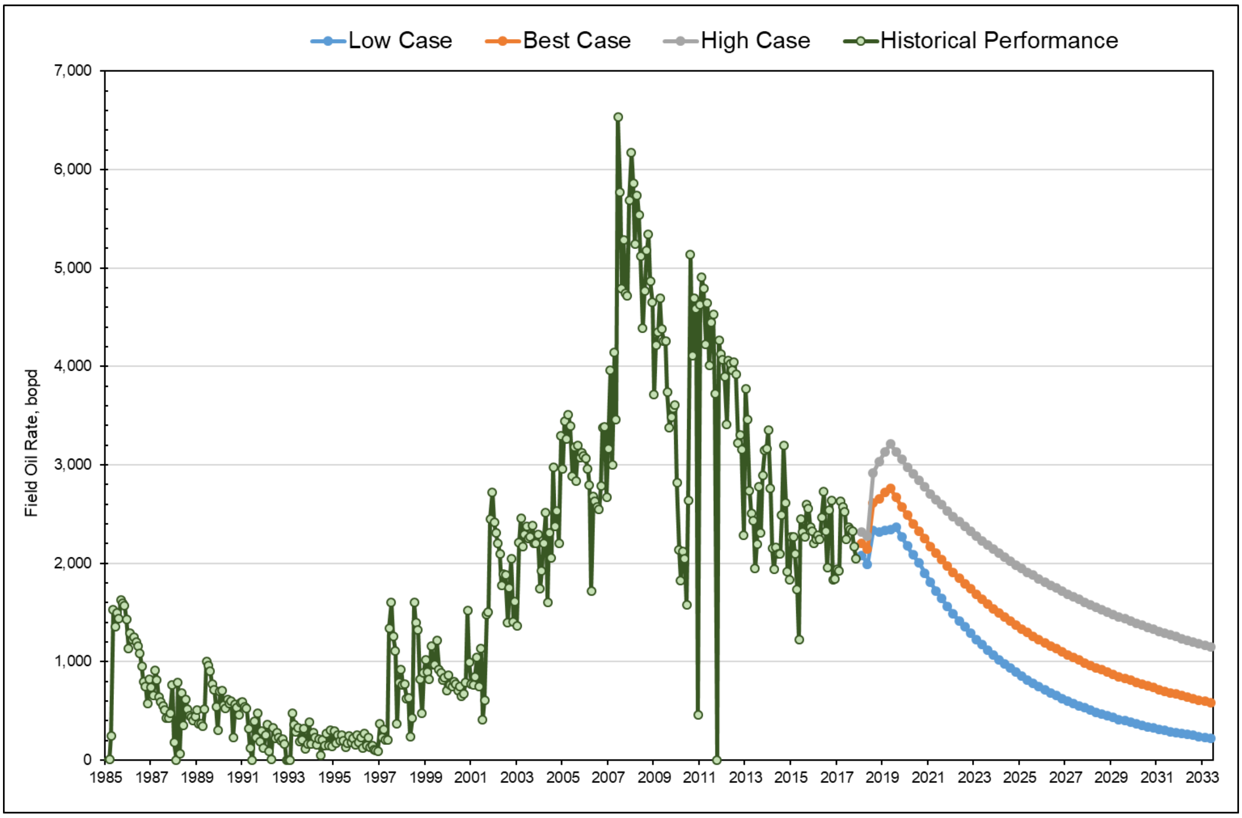
Notes:

1. EUR represents an estimate of technically recoverable volumes with no consideration of economics, and includes volumes already produced; it does not equate to Reserves.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

3.7 Reserves

Reserves were assigned to the active wells as well as the new producer (GUE10A side-track). Benefits from four workovers and water injection in Bireno were also included in the Reserves (Figure 13).

Figure 13: Guebiba Oil Production Forecast



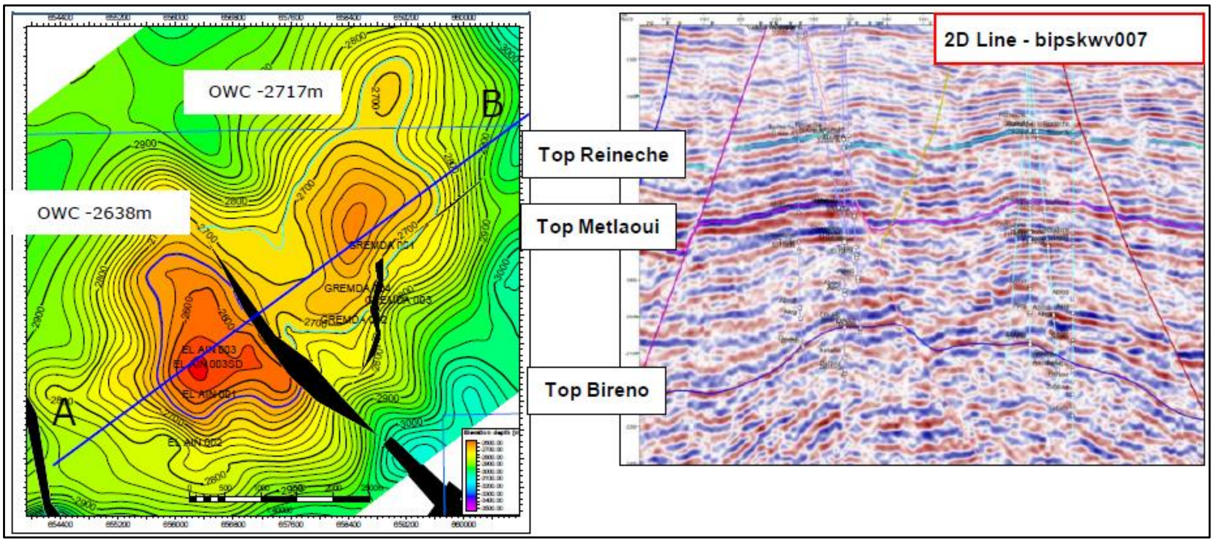
3.8 Contingent Resources

No Contingent Resources are assigned at this time.

4 El Ain, Gremda, Rhemoura

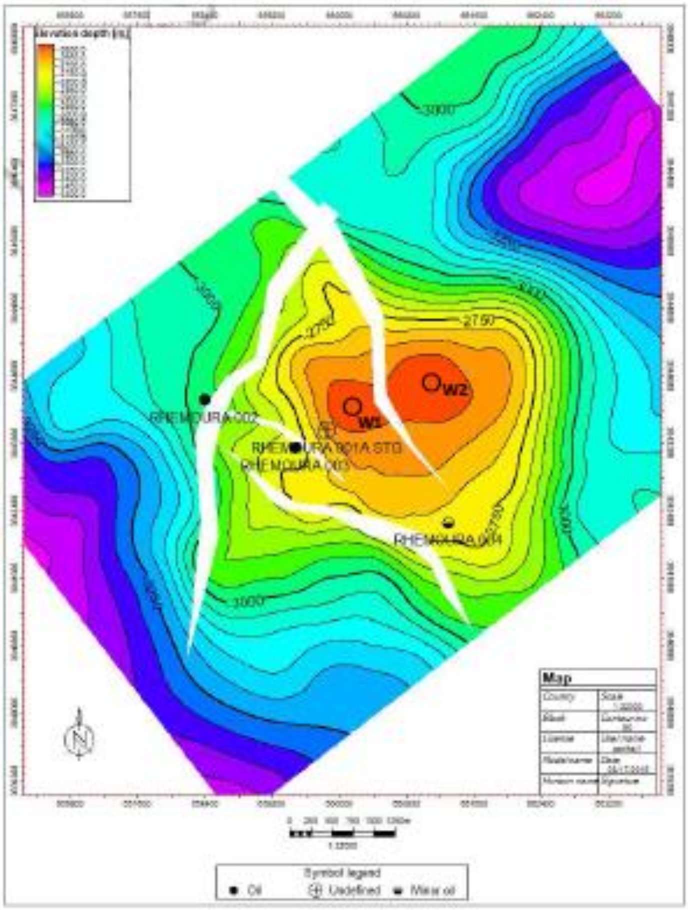
El Ain, Gremda and Rhemoura are onshore fields geologically very similar to Guebiba with Bireno being the main reservoir. Fault and horizon interpretation was carried out using 2D seismic lines. The structures are faulted and fault bounded NW-SE anticlines compartmentalised by normal faults with throw of about 10 m. Gremda is separated from the El Ain structure by a sealing NW-SE trending normal fault. The Bireno top reservoir structure map for El Ain and Gremda is shown in Figure 14. Rhemoura field is characterised by a complex tectonic history, the latest structural interpretation by OMV shows an upside towards NE of the structure (Figure 15).

Figure 14: Bireno Reservoir Top Structure Map and Seismic Section, El Ain and Gremda Fields



Source: OMV

Figure 15: Bireno Reservoir Top Structure Map, Rhemoura Field

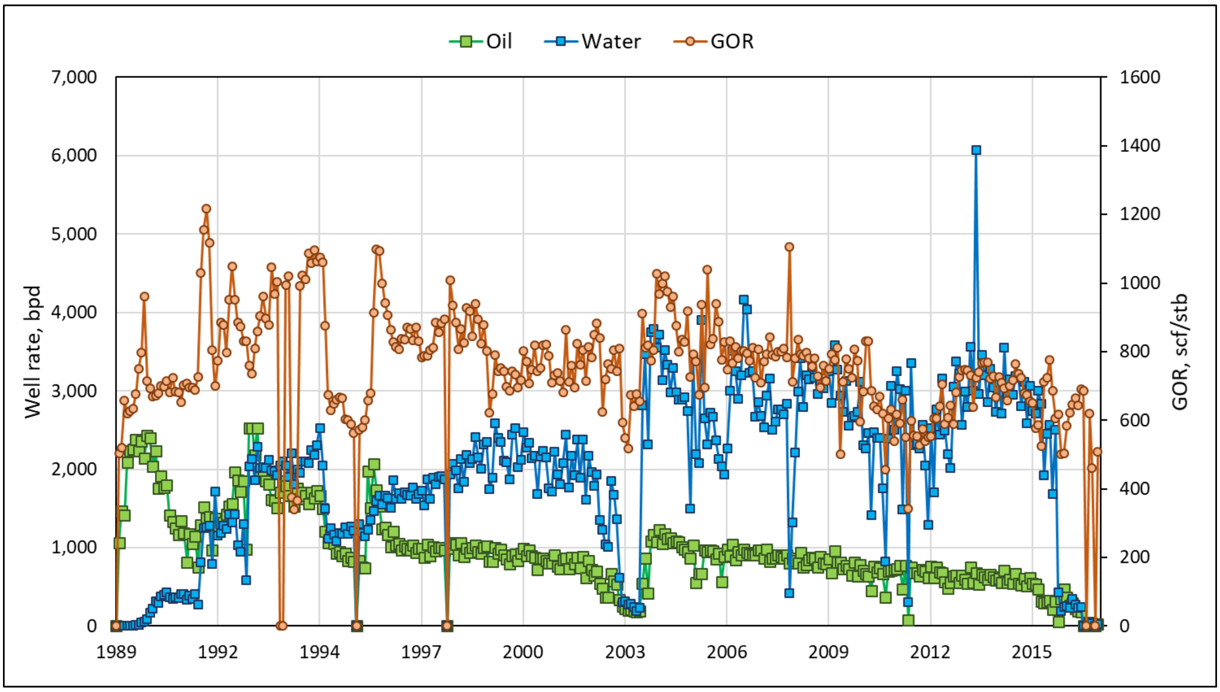


Source: OMV

4.1 Historical Performance

Production from El Ain started in 1989 (Figure 16) and reached a peak of 2,500 bopd by 1990. The Bireno reservoir properties are good with reservoir permeability over 100 md and average porosity of 21%. The field also benefits from the aquifer support that comes from SW. There are 6 well penetrations at El Ain. The two main producers are ELAIN02 and ELAIN03SD; these wells have recovered 2.2 MMBbl and 7.2 MMBbl of oil respectively (93% of total field recovery to date). The field is currently shut in as the producers have casing integrity problems.

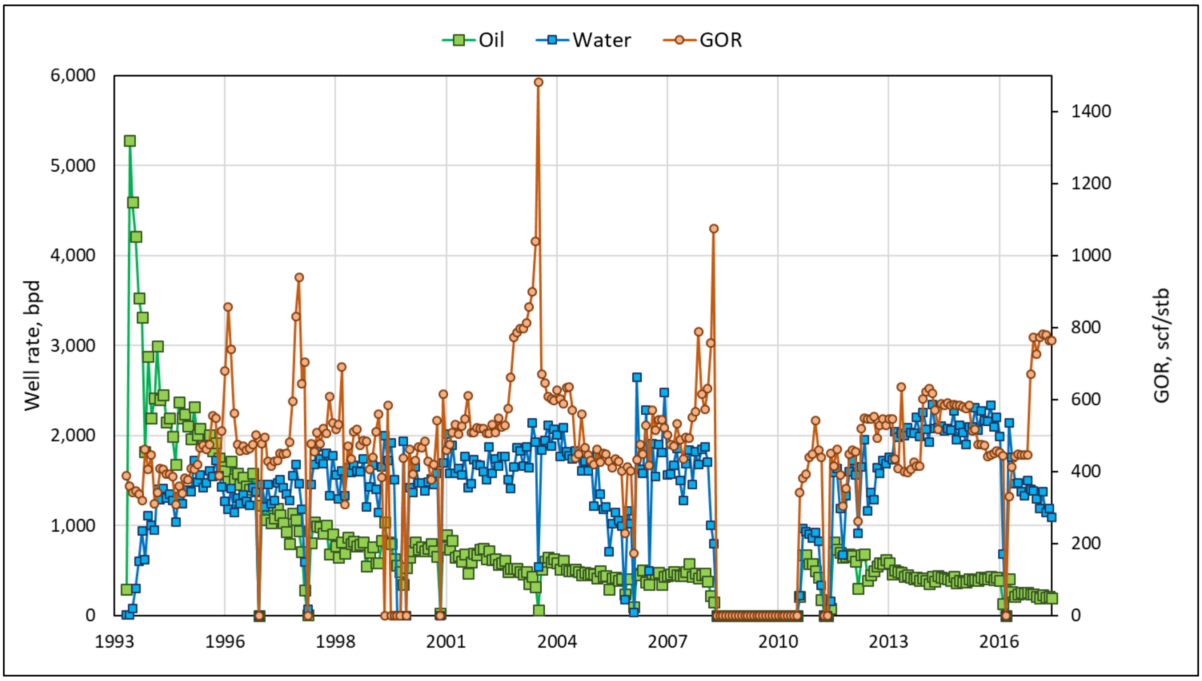
Figure 16: El Ain Historical Production



Production from Gremda started in 1992, but the field was abandoned after experiencing steep decline, with a cumulative oil production of only 61 MBbl.

Rhemoura is producing since 1993 (Figure 17). Pressure data confirms strong aquifer support. The Bireno reservoir at Rhemoura has average matrix permeability of 15 md and fracture permeability up to 180 md. Porosity ranges from 15% to 19%. The field has 5 well penetrations in total with one active producer (RHE01ASTG) equipped with an ESP.

Figure 17: Rhemoura Historical Production



Strong aquifer drive, in conjunction with the low oil viscosity, has resulted in high oil recovery under primary depletion for both El Ain and Rhemoura. Both fields have long production history so performance methods for estimating connected and remaining recoverable volumes can be used with an acceptable degree of confidence. OMV has built material balance models to estimate a range of connected STOIIP for El Ain and Rhemoura that GCA has reviewed and accepted as reasonable.

4.2 Development Plans

OMV's plan for El Ain is to workover two shut-in producers and select for them a suitable lifting concept. OMV has demonstrated that there is a commitment from TPS shareholders to perform the workovers early in 2019. There are no further activities planned for Rhemoura apart from keeping the single producing well active. GCA used DCA to forecast performance for the active well and for two El Ain wells (Table 13).

Table 13: STOIIP and Oil Recovery, El Ain and Rhemoura Fields

Field	Low Case		Best Case		High Case	
	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl
El Ain	35.0	11.6	37.5	12.2	40.0	12.9
Rhemoura	22.5	7.2	25.0	7.4	27.5	7.6
Total	**57.5**	**18.7**	**62.5**	**19.5**	**67.5**	**20.5**

Notes:

1. EUR represents an estimate of technically recoverable volumes with no consideration of economics, and includes volumes already produced; it does not equate to Reserves.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

4.3 Reserves

Reserves were assigned to one active well at Rhemora as well as two workovers at El Ain.

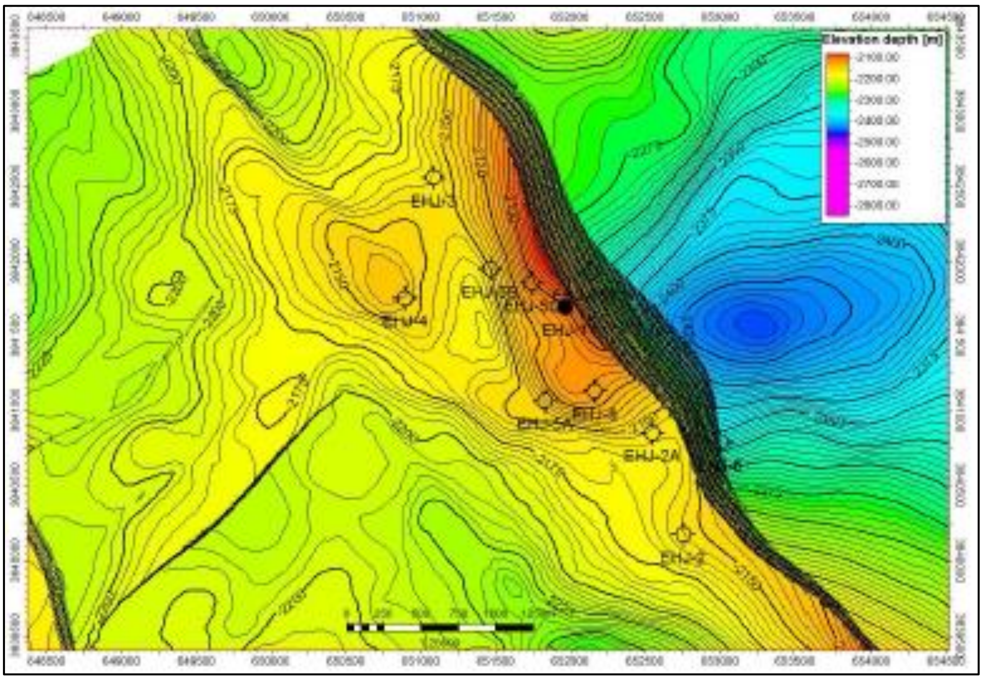
4.4 Contingent Resources

No Contingent Resources are assigned at this time.

5 El Hajeb

Located onshore close to Guebiba, the El Hajeb field was discovered in 1982. The main productive reservoir is the Eocene age El Gueria limestone. The main source rock is the Bou Dabbous formation. The El Hajeb structure is a NW-SE trending structure with a length of 6 km and a maximum width of 1.4 km, bounded by a major normal fault to the east (Figure 18). Since the first discovery well EHJ-1, subsequent appraisal has been unsuccessful. From 1982 to 2005, six additional wells have been drilled and three sidetracked, all targeting the El Gueria limestone as primary objective. All were tested dry. The El Gueria reservoir has porosity in the range of 15-25% and permeability up to 1.2 Darcy. During the appraisal campaign in 2005, well EHJ07ST tested oil in the Souar A Formation. The Souar A lies right above the El Gueria and has porosity of 13-15% and average permeability of 30 mD. GCA used available maps and well data to estimate STOIIP for the productive reservoirs at El Hajeb.

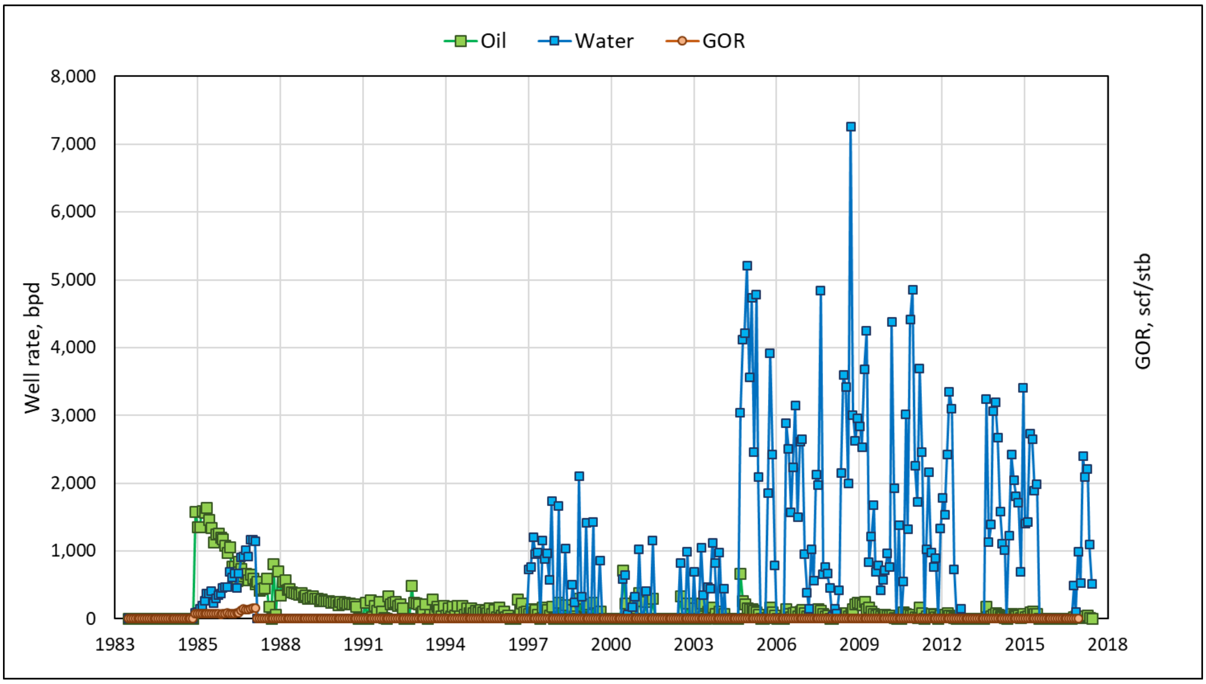
Figure 18: El Gueria Top Reservoir Structure Map, El Hajeb Field



5.1 Historical Performance

In December 1985, well EHJ01 came on-stream and the water-cut increased rapidly (Figure 19). Given the well high productivity and the compatibility of produced water with the Douleb reservoir formation water at Guebiba, EHJ01 became an excellent injection source for the waterflood in Guebiba. In total the ELH01 has produced 2.05 MMBbl of oil from the El Gueria reservoir. The EHJ07ST well has been was producing intermittently at high water cut and has recovered 0.05 MMBbl of oil from the Souar A reservoir.

Figure 19: El Hajeb Historical Production



5.2 Development Plans

The development plan for the El Hajeb field includes production from the two active producers - ELH01 and EHJ07ST. There is a study by OMV on upside potential that includes the Bireno and Souar A reservoirs, but further exploration and appraisal drilling has not yet been approved by the TPS shareholders. GCA used DCA to generate production forecasts for the two active producers (Table 14).

Table 14: El Hajeb STOIIP and Oil Recovery

Field	Low Case		Best Case		High Case	
	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl	STOIIP, MMBbl	EUR, MMBbl
El Guria	3.9	2.14	6.3	2.18	9.7	2.22
Sour A	0.38	0.07	0.38	0.10	0.38	0.14
Total	**57.5**	**18.7**	**62.5**	**19.5**	**67.5**	**20.5**

Notes:

1. EUR represents an estimate of technically recoverable volumes with no consideration of economics, and includes volumes already produced; it does not equate to Reserves.
2. Totals may not exactly equal the sum of the individual entries due to rounding.

5.3 Reserves

Reserves were assigned for the two active producers at El Hajeb.

5.4 Contingent Resources

No Contingent Resources are assigned at this time.

6 TPS Facilities

TPS operates five (5) fields. Rhemora and El Ain fields are located in highly populated areas of the town of Sfax, Guebiba and El Hajeb are in amidst olive groves and Cercina is a shallow offshore field. Two oils of different quality are produced from the TPS fields. Oil from El Ain is light (39 deg API) and sold as Zarzaitine blend, while the other fields produce a slightly heavier (31-33 deg API) crude. These two types are delivered to CFTP (Compagnie Franco Tunisienne des Petroles) and transferred to TRPASA (Compagnie Des Transports Par pipe-lines au Sahara), but stored separately. Crudes from El Ain, Rhemoura and the Bireno reservoir at Guebiba are sour, with hydrogen sulphide concentrations of several thousands of ppm. The TPS facilities are designed to handle this. A schematic map of the TPS facilities location is shown in Figure 20.

Figure 20: TPS Facilities Location

Source: OMV

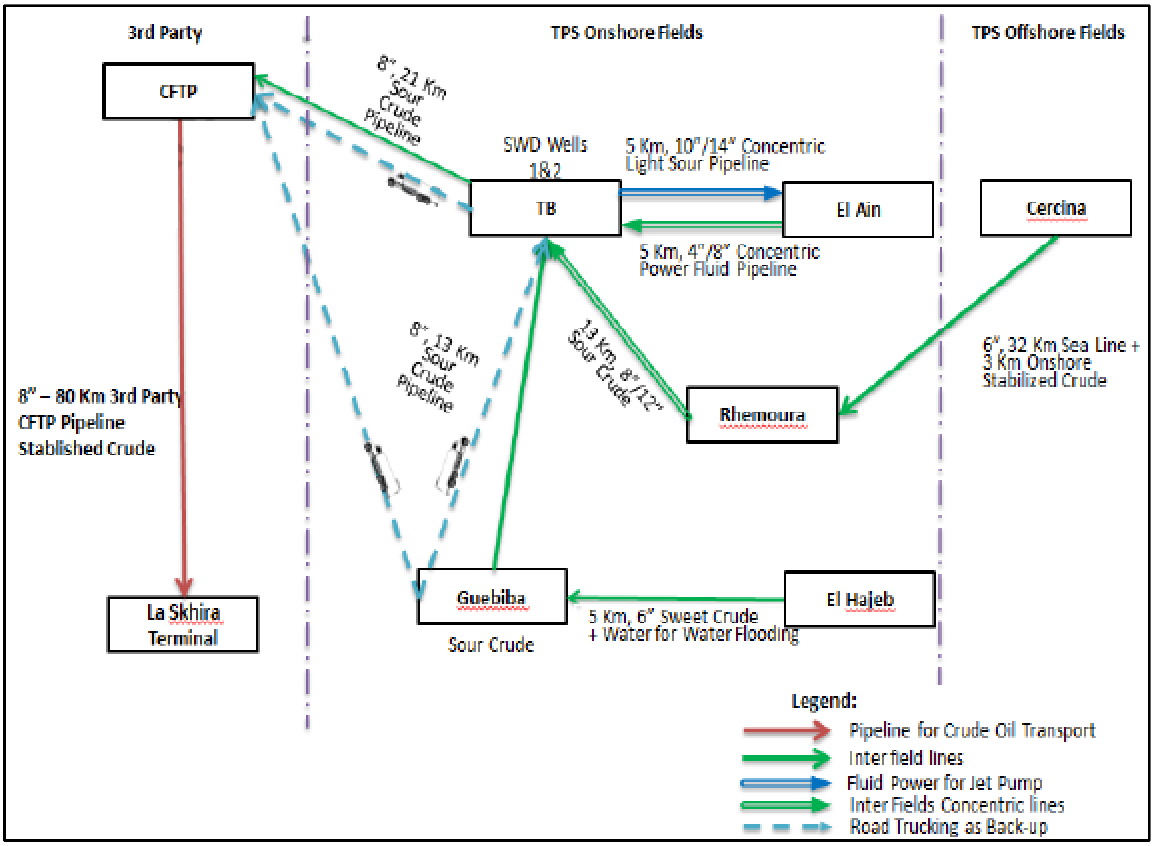
The Cercina field is located offshore near Kerkennah Islands (7 km from shore) in a water depth of 3-5m. Cercina has currently seven oil producers, all activated with ESPs. All Cercina wells have surface wellheads and each wellhead is located on a small single-wellhead platform. The Delta platform hosts the main processing equipment such as separator skids, flare scrubbers, interconnecting piping, flaring facilities and the control room. The platform has space constraints due to its shape and existing installed equipment. Wells are linked through 4" and 2" flowlines to the Delta platform. Produced fluids are pumped to the Rhemoura site via 6", 35 km oil/water pipeline (32 km offshore, 3 km onshore). Cercina and Rhemoura fluids are comingled at the Rhemoura facilities and transported to the Tank Battery through an 8"x12" concentric pipeline (14 km). The Cercina platform is powered by three generators which provide power for running the ESPs and other utilities (e.g. lighting, compressors).

The Guebiba station is located amidst olive groves, 15 km south west of Sfax. The station processes fluids from Guebiba and the nearby El Hajeb field. It has four first stage separators, two dedicated for wells producing sour oil from the Bireno reservoir, one for wells producing from the Douleb reservoir and one for El Hajeb wells. TPS recently added a second stage separation unit.

Fluids from all the TPS fields are gathered at the Tank Battery, where final processing takes place for Cercina, Rhemoura and El Ain produced volumes. Water is disposed of at the Tank Battery using two dedicated water disposal wells. Gas is partially used for power generation, with any remainder flared. After processing, the sour crude is transported via pipelines to the CFTP facility and La Skhira export terminal. El Ain crude is trucked to the CFTP facility. A schematic of the TPS oil transport network is shown in Figure 21.

The CFTP facility is owned by a third-party company and is located at Sidi El Itayem (25 km NW of Sfax). It provides services for crude transport to La Skhira terminal. CFTP has truck loading/offloading stations for light and heavy crude, storage tanks and the export line to La Skhira. There is a 2,000 Bbl storage tank at the CFTP site that is dedicated to TPS crude. Light crude from El Ain is blended with other crudes at CFTP.

Figure 21: TPS Crude Oil Transport Network



6.1 Site Visit

A site visit was undertaken by a Senior Advisor from GCA in July, 2018. One day was spent visiting the onshore sites and a second day visiting the offshore facilities at Cercina.

GCA's visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. The site visits were limited in duration (6-7 hours in total actually at the facilities) and no testing of any kind was carried out. Each visit provided a snapshot of the overall facilities, pipelines and well sites, but it should be recognized that such short visits can only provide an overview of the condition of the facilities and the state of operations. GCA does not warrant they are in compliance with any applicable regulations in terms of standards, rating, health, safety, and environment.

GCA's overall impression was that the facilities appeared generally to be in good condition and fit for purpose relating to the current operations. All of the plants have been in operation for over twenty years but none show any more signs of wear and tear that is consistent with its age – a good sign of a well-run maintenance regime. No risk to continued operation due to mechanical conditions was obviously apparent, although ongoing maintenance remains important to the longevity of the facilities.

Adequate attention appears to be paid to the softer, yet very important, operational aspects of Health, Safety, Security and Environmental consideration, pointing to a well-run operation. Although no formal survey was undertaken, it appears that the TPS personnel have a suitable level of experience.

No obvious safety hazards were noted and there were no complaints from the staff about lack of safety measures. Photos from the Site Visit are shown in Appendix II.

7 Economic Assessment

GCA has conducted an economic limit test (ELT) for each case to assess Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves. The economic limit (or economic cut-off) is defined as the production rate beyond which the net operating cash flows are negative; this is the point in time that defines the end of the project's economic life. Additionally, GCA has calculated the Reserves and NPVs Net to OMV's Working Interest (WI) in each Concession, which requires deduction of the royalty payable in each case.

These assessments are based upon GCA's understanding of the fiscal and contractual terms governing the asset, and the various economic and commercial assumptions described herein.

The Effective Date of the evaluation is 30th June, 2018.

7.1 Contract and Fiscal Terms

The relevant elements of the Tunisian fiscal regime for petroleum operations as they currently stand are summarised below and are assumed to remain constant for the period of evaluation.

7.1.1 Domestic Supply Obligation (DMO)

20% of all oil produced within the Concessions is sold in the domestic market at a 10% discount to the realised export prices.

7.1.2 Royalty

Royalty is payable on pre DMO revenues and generally ranges between 2% and 15%.

The royalty rates on oil production for Cercina/Cercina Sud, Gremda/Al Ain and Rhemoura Concessions are based on their respective R-Factors (see Table 15). The R-Factor is defined as a ratio of cumulative net revenue to total cumulative expenditure. Estimates of cumulative net revenue and total cumulative expenditure for each concession as at 30th June, 2018 were provided by OMV.

The royalty on oil production applicable to El Hajeb/Guebiba Concession is flat 15% and not dependent on R-Factor.

Table 15: Royalty Based on R Factor for Cercina/Cercina Sud, Gremda/Al Ain and Rhemoura Concessions

Oil	
R Factor	Royalty (%)
< 0.5	2.0
0.5 – 0.8	5.0
0.8 – 1.1	7.0
1.1 – 1.5	10.0
1.5 – 2.0	12.0
2.0 – 2.5	14.0
> 2.5	15.0

7.1.3 Corporate Income Tax (CIT)

The CIT rates for Cercina/Cercina Sud, Gremda/Al Ain and Rhemoura are based on the same R-Factors as those used to calculate Royalty, and are shown in Table 16. The CIT rate paid for El Hajeb/Guebiba Concession is flat 60% and not dependent on R-Factor. No tax losses have been assumed to be carried forward.

Table 16: CIT Based on R Factor for Cercina/Cercina Sud Gremda/Al Ain and Rhemoura Concessions

Oil		Gas	
R Factor	CIT Rate (%)	R Factor	CIT Rate (%)
< 1.5	50.0	< 2.5	50.0
1.5 – 2.0	55.0	2.5 – 3.0	55.0
2.0 – 2.5	60.0	3.0 – 3.5	60.0
2.5 – 3.0	65.0	> 3.5	65.0
3.0 – 3.5	70.0	-	-
> 3.5	75.0	-	-

7.1.4 Export Tax Duty

An export tax of 1.5% is payable on the revenue (excluding Royalty) from oil sales in the international market for each Concession. However, this payment is considered as advance and can be claimed against CIT payment.

7.2 Costs

Two main sources of the TPS costs data are monthly reports and annual management reports. GCA has reviewed such reports in order to validate the estimates of capital and operating expenditures (CAPEX and OPEX) provided by OMV.

TPS recently spent significant CAPEX on various facilities projects including crude transport pipeline from the Tank Battery to CTPF, extra separation capacity and turbines for flared gas valorisation at Guebiba, barge construction for Cecina offshore activities, and electrical substations at the Tank Battery. The main elements of the future CAPEX are associated with well work:

- US$7 MM on Guebiba 10A sidetrack;
- US$16 MM per new well in Cercina; and
- US$2 MM per major workover and recompletion in El Ain.

OPEX is mainly related to workover activity to maintain ongoing production with annual ESP replacements. Future OPEX was estimated by OMV based on the actual spent by TPS over the last several years. Annual OPEX per concession is listed below:

- US$7 MM in Cercina;
- US$16 MM in El Hajeb/Guebiba;
- US$2 MM in Rhemoura; and
- US$1.25 MM in Gremda/El Ain.

Given the extensive history and well documented track record of expenditure data, the OMV cost estimates were considered reasonable by GCA. For the purposes of the ELTs, Net Reserves and NPV calculations, costs have been escalated at 2% p.a. from 2019 onwards.

7.3 Oil Prices

GCA's 3Q 2018 Brent Crude oil price scenario, shown in Table 17, has been used as the reference oil price.

Table 17: Reference Brent Crude Oil Price Scenario

Year	Price (US$/Bbl)
2018 (remaining)	78.84
2019	75.08
2020	70.19
2021	70.00
2022+	+2.0% p.a.

Oil from Gremda/Al Ain Concession is sold as Zarzaitine blend while oil from all other Concessions is sold as Rhemoura Blend. Based on the historic data of realised sale price shared by OMV, discounts to Brent of US$0.39/Bbl and US$3.05/Bbl has been assumed for Zarzaitine Blend and Rhemoura Blend respectively.

7.4 Results

The results of the ELTs are summarized in Table 18.

Table 18: Economic Cut-Offs

(a) Reserves Cases

Concession	Proved	Proved + Probable	Proved + Probable + Possible
Cercina 1)	2023	2034	2034
El Hajeb/Guebiba	2029	2033	2033
Gremda/El Ain	-	2033	2033
Rhemoura	2022	2033	2033

(b) Contingent Resources Cases

Concession	1C	2C	3C
Cercina	2034	2034	2034

Notes:

1. Includes Cercina Sud.
2. Proved case cut-offs for Cercina and Rhemoura correspond to license expiry rather than an economic limit.

Resulting Reserves, Contingent Resources and NPV at 10% discount rate are shown in Tables 2-5 in the Executive Summary. In addition, Table 19 shows the sensitivity of NPV to discount rate.

Table 19: Post-Tax NPV (US$ MM) of Future Cash Flow from Reserves, Net to OMV's Interest, at various Discount Rates, as at 30th June, 2018

Concession	Proved			Proved plus Probable			Proved plus Probable plus Possible		
	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%
Cercina/Cercina Sud	2.2	1.9	1.6	40.9	38	35.3	55.8	50.7	46.2
El Hajeb/Guebiba	22.9	22.6	22.1	43.2	40.6	38.1	67.4	61.1	55.8
Gremda/Al Ain	-	-	-	12.9	11.6	10.5	18.1	16	14.2
Rhemoura	-0.9	-0.8	-0.7	1.8	1.8	1.8	3.9	3.6	3.3
Total	**24.2**	**23.7**	**23.0**	**98.8**	**92.0**	**85.7**	**145.2**	**131.4**	**119.5**

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. All cash flows are discounted on a mid-period basis to 30th June, 2018.
3. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

Additionally, NPVs have been calculated for the Contingent Resources in the Cercina/Cercina Sud Concession and are shown in Table 20 below.

Table 20: Unrisked Post-Tax NPV (US$ MM) of Potential Future Cash Flow from Contingent Resources, Net to OMV's Interest, at various Discount Rates, as at 30th June, 2018

Concession	1C			2C			3C		
	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%	7.5%	10.0%	12.5%
Cercina/Cercina Sud	6.1	4.9	3.9	27.3	22.7	19.0	49.4	39.5	31.7

Notes:

1. The NPVs are calculated from discounted cash flows incorporating the fiscal terms governing the asset.
2. All cash flows are discounted on a mid-period basis to 30th June, 2018.
3. The NPVs reported here are "unrisked" in the sense that no adjustment has been made for the risk that the developments may not go ahead in the form envisaged or may not go ahead at all (i.e. no "Chance of Development" factor, as defined under PRMS, has been applied).
4. The NPVs reported here do not represent an opinion as to the market value of a property or any interest therein.

Basis of Opinion

This document reflects GCA's informed professional judgment based on accepted standards of professional investigation and, as applicable, the data and information provided by Panoro and/or obtained from other sources (e.g. public domain), the limited scope of engagement, and the time permitted to conduct the evaluation.

In line with those accepted standards, this document does not in any way constitute or make a guarantee or prediction of results, and no warranty is implied or expressed that actual outcome will conform to the outcomes presented herein. GCA has not independently verified any information provided by Panoro and/or obtained from other sources, and has accepted the accuracy and completeness of these data. GCA has no reason to believe that any material facts have been withheld from it, but does not warrant that its inquiries have revealed all of the matters that a more extensive examination might otherwise disclose.

The opinions expressed herein are subject to and fully qualified by the generally accepted uncertainties associated with the interpretation of geoscience and engineering data and do not reflect the totality of circumstances, scenarios and information that could potentially affect decisions made by the report's recipients and/or actual results. The opinions and statements contained in this report are made in good faith and in the belief that such opinions and statements are representative of prevailing physical and economic circumstances.

This assessment has been conducted within the context of GCA's understanding of the effects of petroleum legislation and other regulations that currently apply to these properties. However, GCA is not in a position to attest to property title or rights, conditions of these rights (including environmental and abandonment obligations), or any necessary licenses and consents (including planning permission, financial interest relationships or encumbrances thereon for any part of the appraised properties).

GCA has undertaken a site visit to TPS facilities. GCA's visit was undertaken to examine the facilities and operations, and to assess their condition and state of operability. GCA does not warrant they are in compliance with any applicable regulations in terms of standards, rating, health, safety, and environment.

Reserves and Resources Definitions

In the preparation of this report, GCA has used definitions contained within the updated version of the Petroleum Resources Management System (PRMS) published by the Society of Petroleum Engineers, the World Petroleum Council, the American Association of Petroleum Geologists, the Society of Petroleum Evaluation Engineers, the Society of Exploration Geophysicists, the Society of Petrophysicists and Well Log Analysts, and the European Association of Geoscientists and Engineers in June, 2018. An abbreviated form of the PRMS definitions and guidelines is given in Appendix III.

Reserves are those quantities of petroleum that are anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial and remaining (as of the evaluation date) based on the development project(s) applied. All categories of Reserve volumes quoted herein have been determined within the context of an economic limit test assessment (pre-tax and exclusive of accumulated depreciation amounts).

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies.

Contingent Resource volumes reported herein are un-risked in terms of economic uncertainty and commerciality. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

There are numerous uncertainties inherent in estimating reserves and resources, and in projecting future production, development expenditures, operating expenses and cash flows. Oil and gas reserve engineering and resource assessment must be recognized as a subjective process of estimating subsurface accumulations of oil and gas that cannot be measured in an exact way. Estimates of oil and gas reserves or resources prepared by other parties may differ, perhaps materially, from those contained within this report. The accuracy of any reserve estimate is a function of the quality of the available data and of engineering and geological interpretation. Results of drilling, testing and production that post-date the preparation of the estimates may justify revisions, some or all of which may be material. Accordingly, reserve estimates are often different from the quantities of oil and gas that are ultimately recovered, and the timing and cost of those volumes that are recovered may vary from that assumed.

Oil and condensate volumes appearing in this report have been quoted in millions (10^6) of barrels at stock tank conditions (MMBbl). Natural gas volumes have been quoted in billions (10^9) of standard cubic feet (Bscf) and are volumes of sales gas, after an allocation has been made for fuel and process shrinkage losses. Standard conditions are defined as 14.7 psia and 60°F.

GCA's review and audit involved reviewing pertinent facts, interpretations and assumptions made by Panoro or others in preparing estimates of reserves and resources. GCA performed procedures necessary to enable it to render an opinion on the appropriateness of the methodologies employed, adequacy and quality of the data relied on, depth and thoroughness of the reserves and resources estimation process, classification and categorization of reserves and resources appropriate to the relevant definitions used, and reasonableness of the estimates.

Qualifications

GCA is an independent international energy advisory group of more than 50 years' standing, whose expertise includes petroleum reservoir evaluation and economic analysis.

In performing this study, GCA is not aware that any conflict of interest has existed. As an independent consultancy, GCA is providing impartial technical, commercial, and strategic advice within the energy sector. GCA's remuneration was not in any way contingent on the contents of this report.

In the preparation of this document, GCA has maintained, and continues to maintain, a strict independent consultant-client relationship with Panoro. Furthermore, the management and employees of GCA have no interest in any of the assets evaluated or related with the analysis performed, as part of this report.

Staff members who prepared this report hold appropriate professional and educational qualifications and have the necessary levels of experience and expertise to perform the work.

The team was led by Mr Anton Eskov, a Senior Reservoir Engineering with 13 years of industry experience.

The report has been reviewed by Dr John Barker, Technical Director, Reservoir Engineering, who has 33 years of industry experience. He holds an M.A. in Mathematics from the University of Cambridge and a Ph.D. in Applied Mathematics from the California Institute of Technology. He is a member of the Society of Petroleum Engineers and of the Society of Petroleum Evaluation Engineers.

Yours sincerely,

Gaffney, Cline & Associates

Project Manager
Anton Eskov, Petroleum Engineer

John Barker

Reviewed by
John Barker, Regional Director – Reservoir Engineering

Gaffney, Cline & Associates

Appendix I
Glossary of Standard Terms

GLOSSARY

Standard Oil Industry Terms and Abbreviations

ABEX	Abandonment expenditure
API	American Petroleum Institute
°API	Degrees API (a measure of oil density)
AVO	Amplitude versus offset
B	Billion (10^9)
Bbl	Barrels
/Bbl	Per barrel
BBbl	Billion barrels
bcpd	Barrels of condensate per day
BHP	Bottom hole pressure
blpd	Barrels of liquid per day
Bm^3	Billion cubic metres
bopd	Barrels oil per day
bpd	Barrels per day
Bscf or Bcf	Billion standard cubic feet
Bscfd or Bcfd	Billion standard cubic feet per day
BS&W	Bottom sediment and water
BTU	British thermal units
bwpd	Barrels of water per day
°C	Degrees Celsius
CAPEX	Capital expenditure
cf	Standard cubic feet
cfd	Standard cubic feet per day
cm	Centimetres
cP	Centipoise (a measure of viscosity)
CSG	Coal seam gas
CT	Corporation tax
DCQ	Daily contract quantity
Dev	Developed
DST	Drill stem test
E&A	Exploration & appraisal
E&P	Exploration and production
EBIT	Earnings before interest and tax
EBITDA	Earnings before interest, tax, depreciation and amortisation
EI	Entitlement interest
ELT	Economic limit test
EOR	Enhanced oil recovery
ESP	Electrical submersible pump
EUR	Estimated ultimate recovery
€ / EUR	Euro
°F	Degrees Fahrenheit
FDP	Field development plan

FSO	Floating storage and offloading vessel
ft	Foot/feet
g	Gram
g/cc	Grams per cubic centimetre
G&A	General and administrative costs
GBP	Pounds Sterling
GCoS	Geological chance of success
GDT	Gas down to
GIIP	Gas initially in place
GOC	Gas oil contact
GOR	Gas oil ratio
GRV	Gross rock volume
GWC	Gas water contact
HCIIP	Hydrocarbons initially in place
HDT	Hydrocarbons down to
HSE	Health, Safety and Environment
HUT	Hydrocarbons up to
H_2S	Hydrogen sulphide
IOR	Improved oil recovery
IRR	Internal rate of return
J	Joule (Metric measurement of energy; 1 kilojoule = 0.9478 BTU)
KB	Kelly bushing
kJ	Kilojoules (one thousand Joules)
km	Kilometres
km^2	Square kilometres
kPa	Kilopascal (one thousands Pascals)
kW	Kilowatt
kWh	Kilowatt hour
LKG	Lowest known gas
LKH	Lowest known hydrocarbons
LKO	Lowest known oil
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
LTI	Lost time injury
LWD	Logging while drilling
m	Metres
M	Thousand
m^3	Cubic metres
MBbl	Thousands of barrels
Mbopd	Thousands of barrels of oil per day
Mcf or Mscf	Thousand standard cubic feet
MCM	Management committee meeting
m^3d	Cubic metres per day
mD	Millidarcies (a measure of rock permeability)
MD	Measured depth
MDT	Modular dynamic tester (a wireline logging tool)

Mean	Arithmetic average of a set of numbers
Median	Middle value in a set of values
mg/l	milligrams per litre
MJ	Megajoules (one million Joules)
Mm^3	Thousand cubic metres
Mm^3d	Thousand cubic metres per day
MM	Million
MMBbl	Millions of barrels
MMBTU	Millions of British Thermal Units
MMcf or MMscf	Million standard cubic feet
Mode	Value that exists most frequently in a set of values = most likely
Mcfd or Mscfd	Thousand standard cubic feet per day
MMcfd or MMscfd	Million standard cubic feet per day
MW	Megawatt
MWD	Measuring while drilling
MWh	Megawatt hour
mya	Million years ago
n/a	Not applicable
NGL	Natural gas liquids
N_2	Nitrogen
NOK	Norwegian krone
NPV	Net Present Value
NPV10	Net Present Value at 10% annual discount rate
NTG	Net to gross ratio
OBM	Oil based mud
OCM	Operating committee meeting
ODT	Oil down to
OPEX	Operating expenditure
OWC	Oil water contact
p.a.	Per annum
Pa	Pascal (metric measurement of pressure)
P&A	Plugged and abandoned
PD	Proved developed
PDP	Proved developed producing
%	Percentage
PI	Productivity index
ppm	Parts per million
PRMS	Petroleum Resources Management System
PSC / PSA	Production sharing contract / Production sharing agreement
PSDM	Post stack depth migration
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
PUD	Proved undeveloped
PVT	Pressure volume temperature
P10	Value with a 10% probability of being exceeded

P50	Value with a 50% probability of being exceeded
P90	Value with a 90% probability of being exceeded
RF	Recovery factor
RFT	Repeat formation tester (a wireline logging tool)
RT	Rotary table
R_w	Resistivity of water
SCAL	Special core analysis
scf	Standard cubic feet
scfd	Standard cubic feet per day
S_o	Oil saturation
SPE	Society of Petroleum Engineers
SPEE	Society of Petroleum Evaluation Engineers
SRP	Sucker rod pump
ss	Subsea
ST	Side track
stb	Stock tank barrel
STOIIP	Stock tank oil initially in place
S_w	Water saturation
t	Tonnes
TD	Total depth
te	Tonnes equivalent
THP	Tubing head pressure
TJ	Terajoules (10^{12} Joules)
Tscf or Tcf	Trillion standard cubic feet
TCM	Technical committee meeting
TVD	True vertical depth
TVDss	True vertical depth subsea
Undev	Undeveloped
USGS	United States Geological Survey
US$	United States Dollar
VAT	Value added tax
VSP	Vertical seismic profiling
WC	Water cut
WI	Working interest
WPC	World Petroleum Council
WTI	West Texas Intermediate
wt%	Weight percent
WUT	Water up to
1C	Low estimate of Contingent Resources
2C	Best estimate of Contingent Resource
3C	High estimate of Contingent Resources
2D	Two dimensional
3D	Three dimensional
4D	Four dimensional (time lapse)
1H13	First half (6 months) of 2013 (example of date)
1P	Proved Reserves

2P	Proved plus Probable Reserves
3P	Proved plus Probable plus Possible Reserves
2Q14	Second quarter (3 months) of 2014 (example of date)

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Appendix II
TPS Facilities Photographs

Panoro Energy Limited
5th November, 2018

Figure AII.1: Cercina 3 Wellhead

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Figure AII.2: Cerina HSE Borad

Figure AII.3: Cercina Manifold Platform

Figure AII.4: Cercina Platform

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Figure AII.5: El Ain 01 Wellhead

Figure AII.6: Flares at Tank Battery

Figure AII.7: Flaring at Geubiba

Figure AII.8: Gubiba 2nd Stage Separators

Figure AII.9: Gubiba Processing Area

Figure AII.10: Gubiba Well Flowlines

Figure AII.11: Pig Receiver El Ain

Figure AII.12: Pig Receiver

Figure AII.13: Rhem01 Well Site

Figure AII.14: Tank Battery Personnel Board

Figure AII.15: Thyna Barge

Figure AII.16: TPS HSSE

Figure AII.17: Water Disposal Well SWDW#1

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Appendix III
Abbreviated Form of SPE PRMS

Society of Petroleum Engineers, World Petroleum Council,
American Association of Petroleum Geologists, Society of Petroleum Evaluation Engineers,
Society of Exploration Geophysicists, Society of Petrophysicists and Well Log Analysts,
and European Association of Geoscientists & Engineers

Petroleum Resources Management System

Definitions and Guidelines ([1])

(Revised June 2018)

Table 1—Recoverable Resources Classes and Sub-Classes

Class/Sub-Class	Definition	Guidelines
Reserves	Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions.	Reserves must satisfy four criteria: discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability (see Section 2.1.2, Determination of Commerciality). This includes the requirement that there is evidence of firm intention to proceed with development within a reasonable time-frame. A reasonable time-frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While five years is recommended as a benchmark, a longer time-frame could be applied where, for example, development of an economic project is deferred at the option of the producer for, among other things, market-related reasons or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented. To be included in the Reserves class, there must be a high confidence in the commercial maturity and economic producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.
On Production	The development project is currently producing or capable of producing and selling petroleum to market.	The key criterion is that the project is receiving income from sales, rather than that the approved development project is necessarily complete. Includes Developed Producing Reserves. The project decision gate is the decision to initiate or continue economic production from the project.

[1] These Definitions and Guidelines are extracted from the full Petroleum Resources Management System (revised June 2018) document.

Class/Sub-Class	Definition	Guideline s
Approved for Development	All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is ready to begin or is under way.	At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies, such as outstanding regulatory approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project decision gate is the decision to start investing capital in the construction of production facilities and/or drilling development wells.
Justified for Development	Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time of reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained.	To move to this level of project maturity, and hence have Reserves associated with it, the development project must be commercially viable at the time of reporting (see Section 2.1.2, Determination of Commerciality) and the specific circumstances of the project. All participating entities have agreed and there is evidence of a committed project (firm intention to proceed with development within a reasonable time-frame}) There must be no known contingencies that could preclude the development from proceeding (see Reserves class). The project decision gate is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.
Contingent Resources	Those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations by application of development projects, but which are not currently considered to be commercially recoverable owing to one or more contingencies.	Contingent Resources may include, for example, projects for which there are currently no viable markets, where commercial recovery is dependent on technology under development, where evaluation of the accumulation is insufficient to clearly assess commerciality, where the development plan is not yet approved, or where regulatory or social acceptance issues may exist. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by the economic status.
Development Pending	A discovered accumulation where project activities are ongoing to justify commercial development in the foreseeable future.	The project is seen to have reasonable potential for eventual commercial development, to the extent that further data acquisition (e.g., drilling, seismic data) and/or evaluations are currently ongoing with a view to confirming that the project is commercially viable and providing the basis for selection of an appropriate development plan. The critical contingencies have been identified and are reasonably expected to be resolved within a reasonable time-frame. Note that disappointing appraisal/evaluation results could lead to a reclassification of the project to On Hold or Not Viable status. The project decision gate is the decision to undertake further data acquisition and/or studies designed to move the project to a level of technical and commercial maturity at which a decision can be made to proceed with development and production.

Class/Sub-Class	Definition	Guidelines
Development on Hold	A discovered accumulation where project activities are on hold and/or where justification as a commercial development may be subject to significant delay.	The project is seen to have potential for commercial development. Development may be subject to a significant time delay. Note that a change in circumstances, such that there is no longer a probable chance that a critical contingency can be removed in the foreseeable future, could lead to a reclassification of the project to Not Viable status. The project decision gate is the decision to either proceed with additional evaluation designed to clarify the potential for eventual commercial development or to temporarily suspend or delay further activities pending resolution of external contingencies.
Development Unclarified	A discovered accumulation where project activities are under evaluation and where justification as a commercial development is unknown based on available information.	The project is seen to have potential for eventual commercial development, but further appraisal/evaluation activities are ongoing to clarify the potential for eventual commercial development. This sub-class requires active appraisal or evaluation and should not be maintained without a plan for future evaluation. The sub-class should reflect the actions required to move a project toward commercial maturity and economic production.
Development Not Viable	A discovered accumulation for which there are no current plans to develop or to acquire additional data at the time because of limited production potential.	The project is not seen to have potential for eventual commercial development at the time of reporting, but the theoretically recoverable quantities are recorded so that the potential opportunity will be recognized in the event of a major change in technology or commercial conditions. The project decision gate is the decision not to undertake further data acquisition or studies on the project for the foreseeable future.
Prospective Resources	Those quantities of petroleum that are estimated, as of a given date, to be potentially recoverable from undiscovered accumulations.	Potential accumulations are evaluated according to the chance of geologic discovery and, assuming a discovery, the estimated quantities that would be recoverable under defined development projects. It is recognized that the development programs will be of significantly less detail and depend more heavily on analog developments in the earlier phases of exploration.
Prospect	A project associated with a potential accumulation that is sufficiently well defined to represent a viable drilling target.	Project activities are focused on assessing the chance of geologic discovery and, assuming discovery, the range of potential recoverable quantities under a commercial development program.
Lead	A project associated with a potential accumulation that is currently poorly defined and requires more data acquisition and/or evaluation to be classified as a Prospect.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to confirm whether or not the Lead can be matured into a Prospect. Such evaluation includes the assessment of the chance of geologic discovery and, assuming discovery, the range of potential recovery under feasible development scenarios.
Play	A project associated with a prospective trend of potential prospects, but that requires more data acquisition and/or evaluation to define specific Leads or Prospects.	Project activities are focused on acquiring additional data and/or undertaking further evaluation designed to define specific Leads or Prospects for more detailed analysis of their chance of geologic discovery and, assuming discovery, the range of potential recovery under hypothetical development scenarios.

Table 2—Reserves Status Definitions and Guidelines

Status	Definition	**Guidelines**
Developed Reserves	Expected quantities to be recovered from existing wells and facilities.	Reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor compared to the cost of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-producing.
Developed Producing Reserves	Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.	Improved recovery Reserves are considered producing only after the improved recovery project is in operation.
Developed Non-Producing Reserves	Shut-in and behind-pipe Reserves.	Shut-in Reserves are expected to be recovered from (1) completion intervals that are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.
Undeveloped Reserves	Quantities expected to be recovered through future significant investments.	Undeveloped Reserves are to be produced (1) from new wells on undrilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g., when compared to the cost of drilling a new well) is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

Table 3—Reserves Category Definitions and Guidelines

Category	Definition	**Guidelines**
Proved Reserves	Those quantities of petroleum that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable from a given date forward from known reservoirs and under defined economic conditions, operating methods, and government regulations.	If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability (P90) that the quantities actually recovered will equal or exceed the estimate. The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the LKH as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved. Reserves in undeveloped locations may be classified as Proved provided that: A. The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be commercially mature and economically productive. B. Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with drilled Proved locations. For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.
Probable Reserves	Those additional Reserves that analysis of geoscience and engineering data indicates are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.	It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate. Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria. Probable estimates also include incremental recoveries associated with project recovery efficiencies beyond that assumed for Proved.

Category	Definition	**Guidelines**
Possible Reserves	Those additional reserves that analysis of geoscience and engineering data indicates are less likely to be recoverable than Probable Reserves.	The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high-estimate scenario. When probabilistic methods are used, there should be at least a 10% probability (P10) that the actual quantities recovered will equal or exceed the 3P estimate. Possible Reserves may be assigned to areas of a reservoir adjacent to Probable where data control and interpretations of available data are progressively less certain. Frequently, this may be in areas where geoscience and engineering data are unable to clearly define the area and vertical reservoir limits of economic production from the reservoir by a defined, commercially mature project. Possible estimates also include incremental quantities associated with project recovery efficiencies beyond that assumed for Probable.
Probable and Possible Reserves	See above for separate criteria for Probable Reserves and Possible Reserves.	The 2P and 3P estimates may be based on reasonable alternative technical interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects. In conventional accumulations, Probable and/or Possible Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable or Possible Reserves may be assigned to areas that are structurally higher than the Proved area. Possible (and in some cases, Probable) Reserves may be assigned to areas that are structurally lower than the adjacent Proved or 2P area. Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing faults until this reservoir is penetrated and evaluated as commercially mature and economically productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from a known accumulation by non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources. In conventional accumulations, where drilling has defined a highest known oil elevation and there exists the potential for an associated gas cap, Proved Reserves of oil should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable and Possible oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Figure 1.1—RESOURCES CLASSIFICATION FRAMEWORK

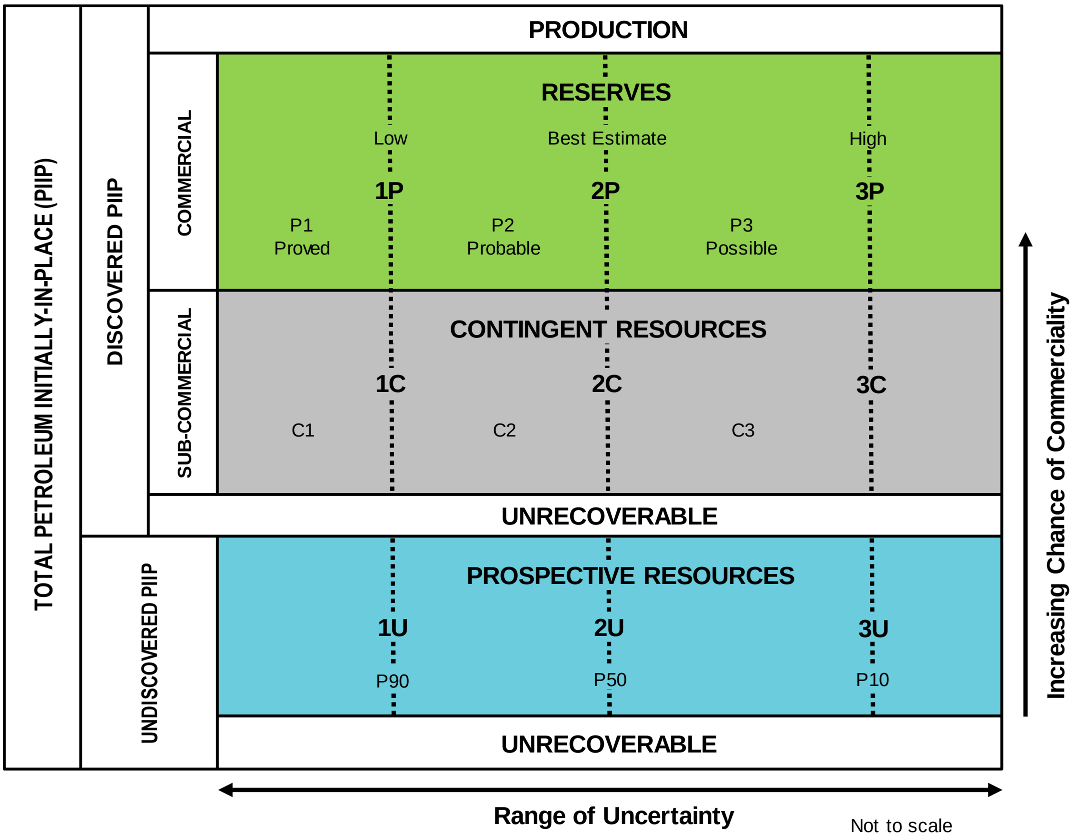
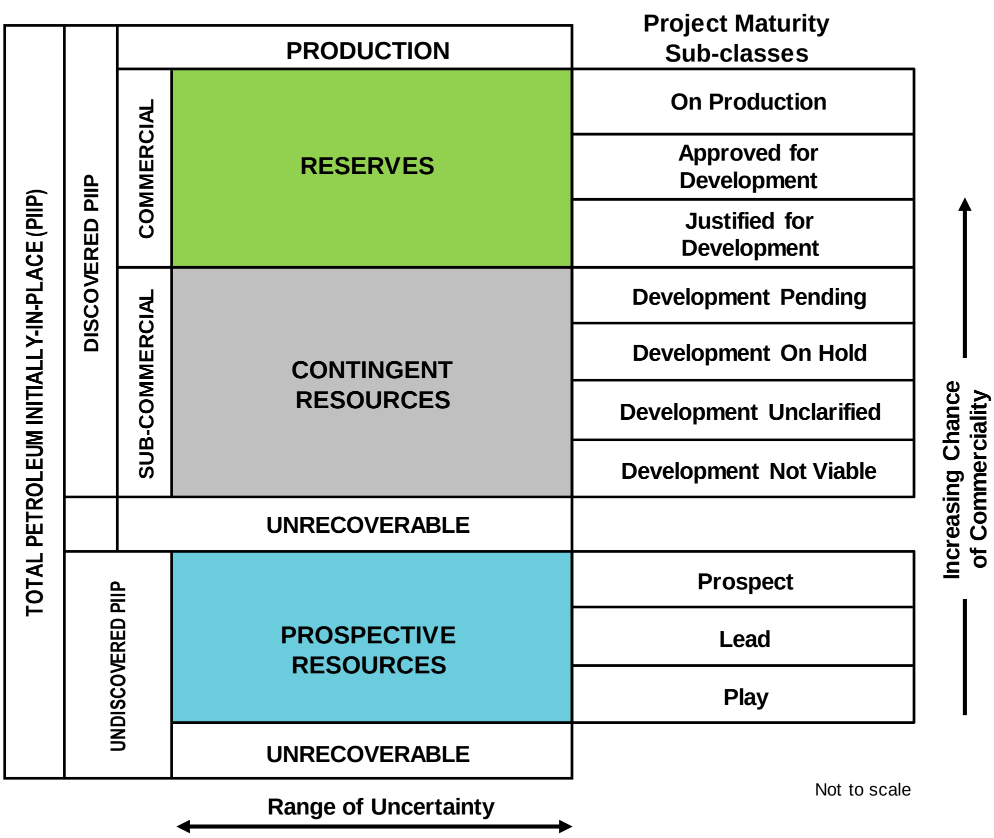


Figure 2.1—SUB-CLASSES BASED ON PROJECT MATURITY



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